Queensland Competition Authority

Draft determination

Regulated retail electricity prices for 2018–19

February 2018

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We wish to acknowledge the contribution of the following staff to this report:

Courtney Chester, Thomas Gardiner, Adam Liddy, Wei Fang Lim and Leigh Spencer

SUBMISSIONS

Closing date for submissions: 9 April 2018

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (QCA). Therefore submissions are invited from interested parties concerning its assessment of regulated retail electricity prices for 2018–19. The QCA will take account of all submissions received within the stated timeframes.

Submissions, comments or inquiries regarding this paper should be directed to:

Queensland Competition Authority
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Tel (07) 3222 0555
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www.qca.org.au/submissions

Confidentiality

In the interests of transparency and to promote informed discussion and consultation, the QCA intends to make all submissions publicly available. However, if a person making a submission believes that information in the submission is confidential, that person should claim confidentiality in respect of the document (or the relevant part of the document) at the time the submission is given to the QCA and state the basis for the confidentiality claim.

The assessment of confidentiality claims will be made by the QCA in accordance with the *Queensland Competition Authority Act 1997*, including an assessment of whether disclosure of the information would damage the person's commercial activities and considerations of the public interest.

Claims for confidentiality should be clearly noted on the front page of the submission. The relevant sections of the submission should also be marked as confidential, so that the remainder of the document can be made publicly available. It would also be appreciated if two versions of the submission (i.e. a complete version and another excising confidential information) could be provided.

A confidentiality claim template is available on request. We encourage stakeholders to use this template when making confidentiality claims. The confidentiality claim template provides guidance on the type of information that would assist our assessment of claims for confidentiality.

Public access to submissions

Subject to any confidentiality constraints, submissions will be available for public inspection at the Brisbane office, or on the website at www.qca.org.au. If you experience any difficulty gaining access to documents please contact us on (07) 3222 0555.

Contents

EXECUTIVE SUMMARY

The Queensland Competition Authority (QCA) has made its draft determination on the regulated retail electricity prices (notified prices) that will apply in regional Queensland from 1 July 2018 to 30 June 2019. In general, notified prices are paid by customers who have not entered into a negotiated or market contract with their retailer. The QCA has been delegated the role of setting notified prices by the Minister for Natural Resources, Mines and Energy (the Minister), and is required to set prices in accordance with that delegation and the *Electricity Act 1994* (the Electricity Act).

It is important to note that the QCA's draft determination will not affect customer bills. The prices discussed in our draft determination are indicative only. To illustrate the hypothetical impacts of these draft notified prices, we provide comparisons of the annual amount typical customers would have paid under 2017–18 notified prices, and the annual amount they would potentially pay under the draft 2018–19 notified prices.

The draft determination forecasts a fall in notified prices for typical customers. This is largely due to reductions in network costs. While there are also forecast reductions in wholesale energy costs, these are expected to be largely offset by increases in the costs of the Large-scale Renewable Energy Target (LRET).

The QCA appreciates the valuable contributions that stakeholders have made to our price determination process, especially those who made submissions to our interim consultation paper (ICP). While we have not referred to all arguments or submissions in the draft determination, we have carefully considered the issues raised in each submission.

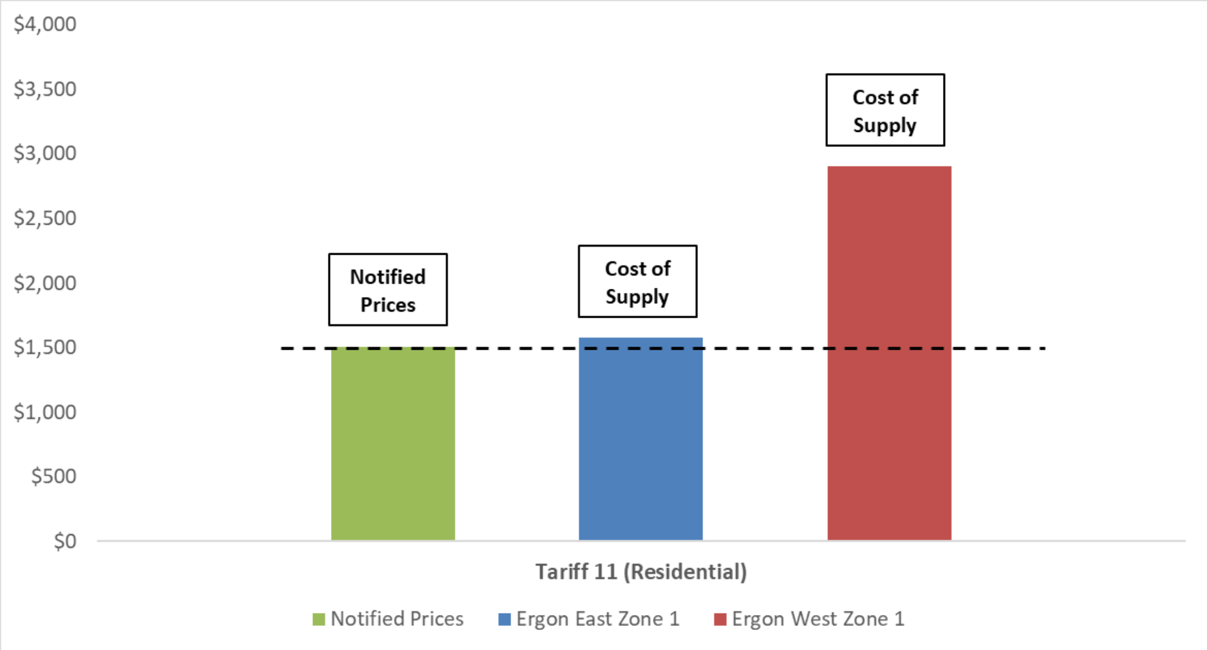
What is the QCA's proposed approach to setting notified prices?

The QCA's proposed approach to setting 2018–19 notified prices is largely consistent with the approach it took in the 2017–18 price determination. Under this approach notified prices are calculated using a network cost plus energy and retail costs (N+R) approach. We also propose to set price levels consistent with the Queensland Government's Uniform Tariff Policy (UTP)—residential and small business customer tariffs are based on the costs of supplying electricity in south east Queensland[1], and large business customer tariffs are based on the lowest costs of supply in regional Queensland.[2]

This UTP approach would result in regional residential, small business and some large business customers paying electricity prices that are generally lower than the costs of supplying these customers. The Queensland Government expects to pay Ergon Retail over $440 million in 2017–18 to subsidise regional electricity customers in 2017–18.

[1] The Energex distribution area.
[2] Ergon Distribution's east pricing zone, transmission region one.

Figure 1 Notified electricity prices for typical residential customers, and actual costs of supply for regional Queensland (incl. GST)



Note: The cost of supply excludes any standing offer adjustment. Ergon East Zone 1 refers to Ergon Distribution's east pricing zone, transmission region 1. Ergon West Zone 1 refers to Ergon Distribution's west pricing zone, transmission region 1.

In broad terms, the N+R methodology produces estimates of efficient south east Queensland price levels for residential and small business customers on market contracts. To be consistent with the UTP, the QCA needs to set notified prices for small customers in regional Queensland that broadly reflect the expected level of standing offer prices in south east Queensland (see Chapter 2). To achieve this, we would need to add an amount (referred to as the standing offer adjustment) to the estimated efficient costs of supply to account for the expected price differential between lowest offers and standing offers in south east Queensland. However, the cover letter to the 2018–19 delegation requires us to consider maintaining the standing offer adjustment at its current level (i.e. 5 per cent). We have proposed to adopt the latter position—that is, to maintain the standing offer adjustment at five per cent (see Chapter 6).

Consistent with our approach in previous price determinations, we have included an allowance for headroom in notified prices for large business customers only. The use of a headroom allowance is a generally accepted approach aimed at stimulating competition and customer engagement in emerging competitive markets. Given that competition in the large business customer segment in regional Queensland has the potential to develop further, particularly in areas where notified prices more closely reflect the actual costs of supply, we consider that including an allowance for headroom will support competition by encouraging customers to engage in the market and seek out better offers.

What impact would the QCA's price determination have on customer bills?

Figures 2–4 compare the annual amount typical customers[3] would have paid under 2017–18 notified prices with the annual amount they would pay under the draft 2018–19 notified prices. Customers will also incur metering charges in addition to the amounts shown in these figures. Customers' metering charges will vary depending on a range of factors, including the type of meter they have installed, the

[3] The typical customer for a given retail tariff is the median or middle customer in terms of consumption out of all customers on that tariff in regional Queensland. The typical customer consumption data is provided by Ergon Retail. More information appears in Appendix H.

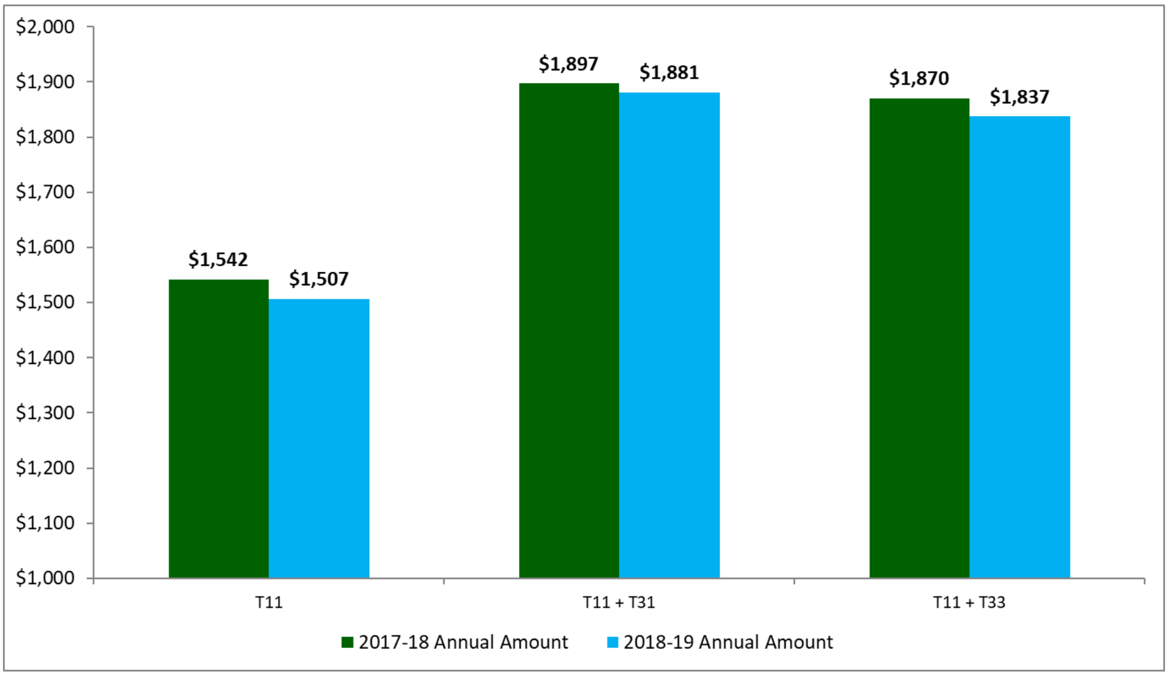
number of different tariffs they use and whether they have a solar photovoltaic (PV) system. As these charges vary from customer to customer, they have not been included in the customer impact analysis.

Residential customers

The main retail tariff for residential customers is tariff 11. Many customers on tariff 11 are also on one of the controlled load tariffs (tariffs 31 and 33).[4]

A typical residential customer on tariff 11 is forecast to pay $35 (2.3 per cent) less for their electricity usage and service fee in 2018–19. For a typical customer on a combination of tariffs 11 and 31 or tariffs 11 and 33, the decrease will be $16 (or 0.8 per cent) and $33 (or 1.7 per cent). However, the impact on each individual will vary according to their consumption.

Figure 2 Draft impact of the change in notified prices on typical residential customers (incl. GST), 2018–19



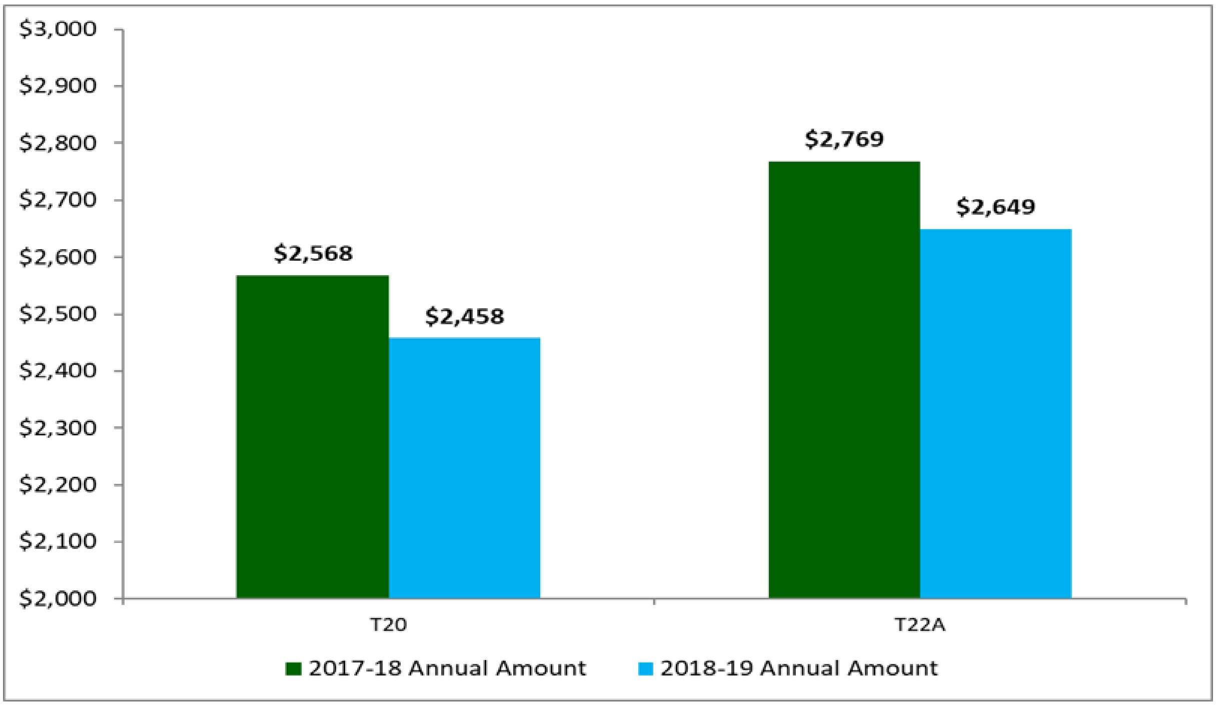
Note: Annual amounts have been rounded to the closest dollar.

Small business customers

A typical small business customer on tariff 20 is forecast to pay $110 (4.3 per cent) less for their electricity usage and service fee in 2018–19. A typical small business customer on tariff 22A is forecast to pay $120 (4.3 per cent) less for their electricity usage and service fee in 2018–19. However, the impact on each individual business will vary according to their consumption and, if the customer is on tariff 22A, the pattern of their consumption.

[4] Controlled load tariffs may be used for appliances such as water heaters and pool pumps. These tariffs are cheaper than tariff 11, as customers are only guaranteed supply for a set number of hours (tariff 31 guarantees supply for 8 hours per day and tariff 33 guarantees supply for 18 hours per day).

Figure 3 Draft impact of the change in notified prices on typical small business customers (incl. GST), 2018–19

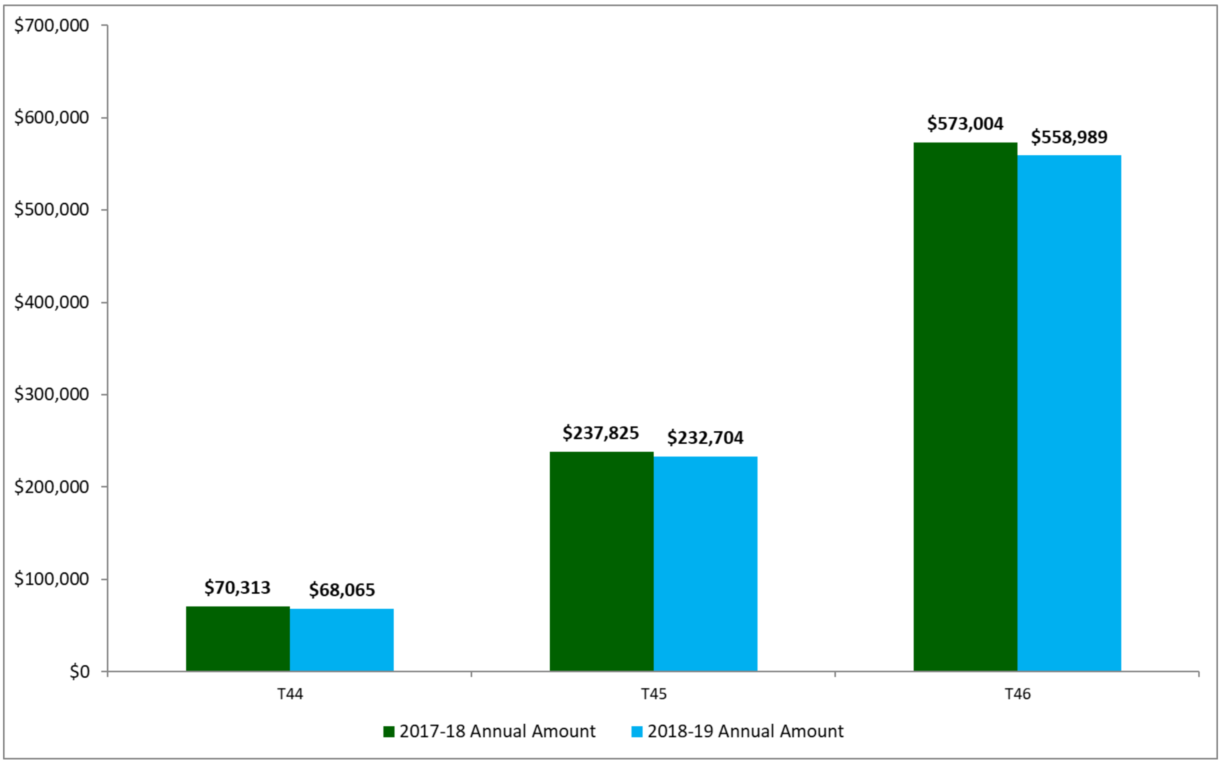


Note: Annual amounts have been rounded to the closest dollar.

Large business customers

A typical large business customer on one of tariffs 44, 45 or 46 is forecast to pay between 2.2 per cent and 3.2 per cent less for their electricity usage and service fee in 2018–19. However, it is important to note that bill impacts for individual customers will vary depending on their level and pattern of consumption.

Figure 4 Draft impact of the change in notified prices on typical large business customers (incl. GST), 2018–19



Note: Annual amounts have been rounded to the closest dollar.

What is the QCA's proposed approach to transitional and obsolete tariffs?

Some business customers, including farmers and irrigators, are supplied under legacy retail tariffs. These transitional and obsolete tariffs have been made available for several years to allow customers to transition their businesses to standard business tariffs. The delegation requires that the QCA consider maintaining these arrangements.

The prices of these tariffs cannot be determined under the standard methodology, as there is no network tariff on which to base network costs. The QCA proposes to maintain transitional and obsolete tariffs at their 2017–18 price levels. Given that standard business tariffs are forecast to decrease, we consider increasing transitional prices, or applying escalation factors, is unnecessary, as the reduction in standard business tariffs will act to somewhat reduce the difference between transitional and standard business tariffs in dollar terms. This approach is consistent with our 2015–16 price determination, where standard business tariffs also decreased.

Given the transitional period for most transitional and obsolete tariffs expires in 2020, we encourage customers on these tariffs to contact their retailer for advice on the most appropriate tariffs for their business and the best way to adapt to standard business tariffs.

Metering charges

The majority of electricity customers pay metering charges that reflect the capital cost and operation of their meter. Previously, these charges were passed through by retailers and were not part of notified prices. However, as a result of changes made under the 'Power of Choice' reforms[5], these charges will form part of notified prices in 2018–19.

Residential and small business customers

Under the Power of Choice reforms, advanced digital meters[6] must be installed when residential and small business customers need a new meter, or where the customer requests one to be installed. These meters, frequently referred to as 'smart' meters, record electricity usage data, and in some cases demand data, every 30 minutes. Typically, these meters can also be read, disconnected, reconnected and reconfigured remotely. Over time, these meters will replace existing 'accumulation' meters[7] for all residential and small business customers. Most large business customers already have meters[8] with similar functionality.

The QCA proposes to base charges for both meter types on costs in south east Queensland, in line with the government's UTP; and to base metering charges for accumulation meters on regulated charges set by the Australian Energy Regulator (AER).[9] Charges for advanced digital meters are not regulated, and as these charges are commercially sensitive, no public sources of information are available on which to base notified prices. As a result, the QCA proposes to base metering charges for advanced digital meters on annual cost data obtained from retailers under section 90A of the Electricity Act.

Table 1 shows the total draft charges for the most common residential and small business tariffs for each meter type. The full list of charges are available in Appendix F.

Table 1 Draft residential and small business metering charges

Tariff(s)	*Accumulation meter charge c/day/meter*	*Advanced digital meter charge c/day/meter*
Tariff 11, 20	9.481	27.590
Tariff 11, 20 with tariff 31 or 33	12.325	30.749

Large business customers

Metering charges for large business customers are not regulated, and as these charges are commercially sensitive, no public sources of information are available on which to base notified prices. As a result, the QCA proposes to base metering charges for advanced digital meters on annual cost data obtained from retailers under section 90A of the Electricity Act.

Table 2 shows draft charges for large business customers.

[5] AEMC, 'Expanding competition in metering and related services', at http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv.

[6] Type 4 and 4A meters.

[7] Type 5 and 6 meters.

[8] Type 1–4 meters.

[9] As these charges were not available at the time of making this draft determination, the QCA has used draft charges supplied by distributors.

Table 2 Draft large business customer metering charges

Customer classification	***Meter charge c/day/meter***
Standard asset customer	141.078
Connection asset customer	328.542
Individually calculated customer	506.502

THE ROLE OF THE QCA – TASK, TIMING AND CONTACTS

The Queensland Competition Authority (QCA) is an independent statutory body that promotes competition as the basis for enhancing efficiency and growth in the Queensland economy.

The QCA's primary role with respect to electricity pricing is to set regulated retail electricity prices in accordance with the requirements of the delegation from the Minister for Natural Resources, Mines and Energy (Appendix A) and the *Electricity Act 1994* (the Electricity Act).

Key dates

Review of regulated retail electricity prices for 2018–19: timetable

Release of the draft determination	By 28 February 2018
Workshops on draft determination	15–27 March 2018
Submissions on draft determination due	9 April 2018
Release of final determination	By 31 May 2018

Registration of interest

http://www.qca.org.au/Contact-us

Contacts

Enquiries regarding this project should be directed to:

ATTN: Leigh Spencer or Adam Liddy
Tel (07) 3222 0555
www.qca.org.au/Contact-us

1 INTRODUCTION

The Queensland Competition Authority (QCA) has received a delegation from the Minister for Natural Resources, Mines and Energy (the Minister) to determine regulated retail electricity prices (notified prices). The delegation specifies that the notified prices we determine will apply to small standard retail contract[10] customers and large standard contract[11] customers in the Ergon Energy Corporation Limited (Ergon Distribution) distribution area from 1 July 2018 to 30 June 2019.[12]

1.1 The review process

Interim consultation paper

On 22 December 2017, we released an interim consultation paper (ICP) advising interested parties of the commencement of our review. We received 16 submissions in response (see Appendix B). The ICP and submissions are available on the QCA's website.[13]

Draft determination

This draft determination contains our draft regulated retail tariffs and prices for 2018–19 (see Chapter 8). In making this draft determination, we have taken into account the requirements of the Electricity Act and the 2018–19 delegation; matters raised in stakeholder submissions; ACIL Allen's draft report on the estimated energy costs; and our own analysis.

As part of our consultation program on the draft determination, we are planning to hold workshops in March 2018 in Bundaberg, Cairns, Cloncurry, Emerald, Mackay, Mount Isa, Rockhampton, Toowoomba, Townsville, Brisbane, and other locations, depending on the level of stakeholder interest. Stakeholders can register their interest for a workshop on our website.[14]

Submissions in response to this draft determination are due by 9 April 2018. Details on how to make a submission are at the front of this paper.

We appreciate the contribution of stakeholders who make submissions on our review. While we may not necessarily reference all arguments or submissions in our determinations, we carefully consider each submission. Any issues that have been raised, but are outside the scope of our review, are discussed in Appendix C. All documents relating to this review are available on our website.[15]

[10] See Schedule 1 of the National Energy Retail Rules.

[11] Large business customers supplied by Ergon Retail are classified as large standard contract customers. Large business customers supplied by other retailers in regional Queensland are classified as large 'market' customers.

[12] See Appendix A for a copy of the delegation.

[13] http://www.qca.org.au/Electricity/Regional-consumers/Reg-Electricity-Prices/In-Progress/Regulated-Electricity-Prices-2018-19

[14] http://www.qca.org.au/workshops.

[15] http://www.qca.org.au/Electricity/Regional-consumers/Reg-Electricity-Prices/In-Progress/Regulated-Electricity-Prices-2018-19

We note that two stakeholders, Queensland Farmers' Federation (QFF)[16] and Canegrowers, expressed disappointment with the 'inappropriately short time frames'[17] to provide responses to the ICP. Stakeholders were given 14 business days within which to respond to the ICP, and we acknowledge that half of those days fell during many businesses' end-of-year shutdown period. However, the delegation to the QCA was significantly delayed, compared to most previous years, due to a state election being held late in 2017 and an extended period during which Government was in 'caretaker mode' (until 12 December 2017).

Given these circumstances, we consider that the consultation period provided on the ICP was unavoidable. However, to assist stakeholders respond to the draft determination, the QCA has scheduled a slightly longer period than in most previous years for stakeholders to provide submissions on the draft determination.

Final determination

We are required to publish a report on our final determination and gazette notified prices no later than 31 May 2018.

1.2 Access to notified prices

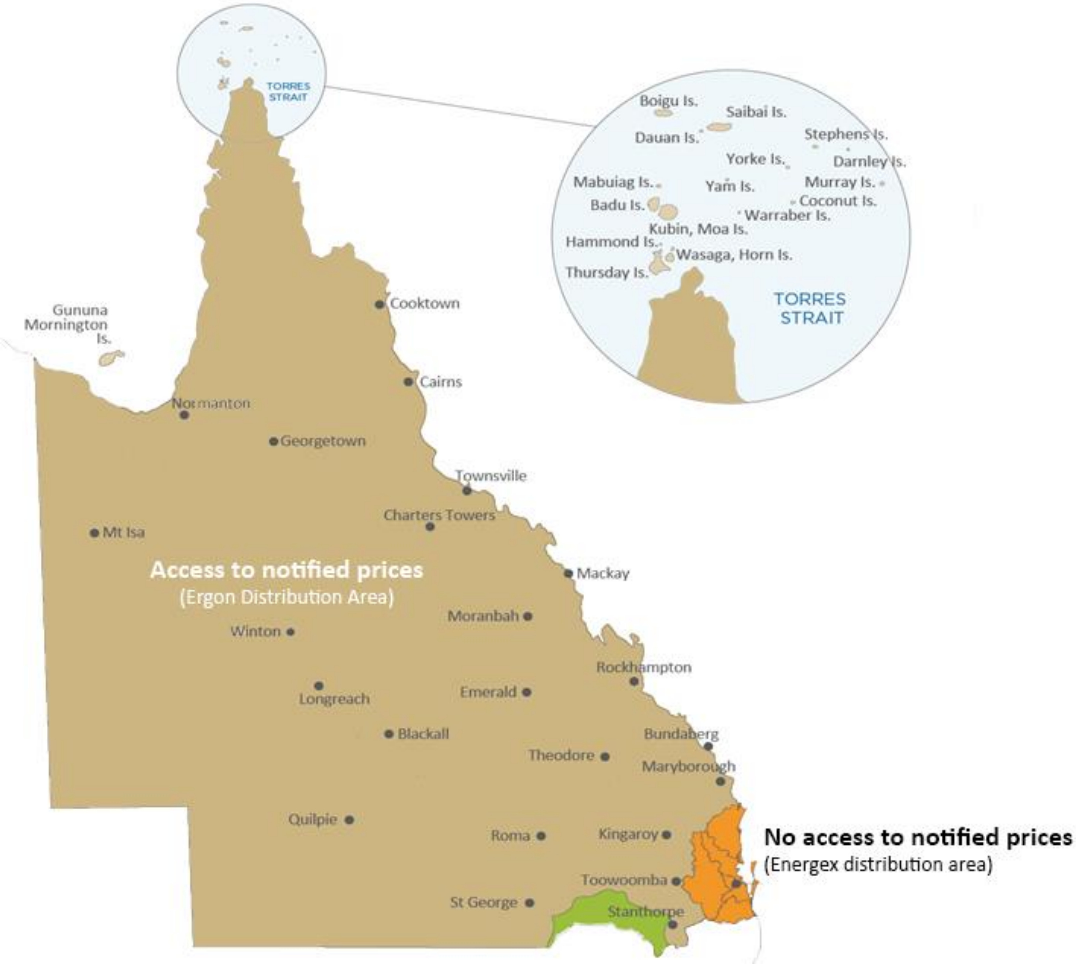
Notified prices are only available to residential, small business and standard contract large business customers who are not located in the Energex distribution area (south east Queensland).[18]

[16] QFF, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 15 January 2018.

[17] Canegrowers, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 19 January 2018, p. 1.

[18] Customers in Essential Energy's distribution area in southern Queensland do not *currently* have access to notified prices, but Origin Energy receives a subsidy to ensure that standard contract customers in that distribution area pay no more than similar customers that have access to notified prices. However, the Minister's delegation for 2018-19 states that the QCA is to decide the prices that a retail entity may charge standard contract customers other than those in the Energex distribution area, where retail price regulation was removed on 1 July 2016.

Figure 5 Access to notified prices



1.3 Legislative framework—the Electricity Act

We must determine notified prices in accordance with our obligations under the Electricity Act. While that Act does not specify criteria or principles to be applied in making a price determination, it directs us to have regard to the following matters:

(a) the actual costs of making, producing or supplying the goods or services

(b) the effect of the price determination on competition in the Queensland retail electricity market

(c) any matter we are required by delegation to consider.[19]

In addition, the Electricity Act also provides that we may have regard to any other matter we consider relevant.

One matter we consider to be relevant is the objects of the Electricity Act, and we intend to have regard to those. The objects of the Electricity Act are to:

[19] Section 90(5)(a) of the Electricity Act.

(a) set a framework for all electricity industry participants that promotes efficient, economical and environmentally sound supply and use

(b) regulate the electricity industry and electricity use

(c) establish a competitive electricity market in line with the national electricity industry reform process

(d) ensure that the interests of customers are protected

(e) take into account national competition policy requirements.[20]

1.4 Matters we are required to consider by the Minister's delegation

The delegation requires us to consider the matters outlined below when determining notified prices for 2018–19. The delegation also requires us to consider that notified prices do not apply to customers in the Energex distribution area, as discussed above.

The Uniform Tariff Policy

Consistent with previous price determinations, we are required to consider the Queensland Government's Uniform Tariff Policy (UTP). The UTP provides that,

> wherever possible, standard contract customers of the same class should pay no more for their electricity, regardless of their geographic location.[21]

The covering letter to the delegation further specifies that, for the purpose of setting notified prices, the Queensland Government's UTP is an important consideration.[22]

The Government considers that under the UTP, notified prices for residential and small business customers in regional Queensland should broadly reflect the expected prices for similar customers on standing offers in south east Queensland. It also considers that notified prices for large business customers in regional Queensland should be based on the costs of supply in the Ergon Distribution east zone, transmission region one, rather than the actual costs of supply. This area is one of the lowest cost areas of the network, and also has the highest number of large and very large customers.

As the actual costs of supplying residential, small business and some large business customers in regional Queensland are generally higher than notified prices[23], the application of the UTP will benefit these customers.

The difference between the costs of supply in south east Queensland and regional Queensland is largely due to the higher network costs associated with supplying electricity over long distances to a low-density customer base. These additional costs are significant, with the Queensland Government expecting to pay a subsidy of $441.1 million in 2017–18 to give effect to the UTP.

'N+R' cost build-up methodology

Consistent with the approach in previous price determinations, we must consider using the Network (N) plus Retail (R) cost build-up methodology when determining notified prices for

[20] Section 3 of the Electricity Act.
[21] Clause 5(b) of the delegation (Appendix A).
[22] A copy of the Minister's covering letter is provided in Appendix A.
[23] The differences in the costs of supply are largely due to the higher network costs associated with supplying electricity over long distances to a low-density customer base.

2018–19. Under this methodology, the N costs (network costs) are generally treated as a pass-through and the R costs (energy and retail costs) are determined by the QCA.

The network cost (N) component

When calculating the N component for each regulated retail tariff, the delegation requires that the QCA consider continuing the general approach it has applied in previous price determinations. This means using the Energex network charges and tariff structures when we determine non-time-of-use retail tariffs[24] for residential and small business customers (tariffs 11, 20, 31, 33, 41 and 91[25]).

When we determine time-of-use[26] and time-of-use demand retail tariffs[27] for residential and small business customers (tariffs 12A, 14, 22A and 24), we must consider basing the N component on the price level of network charges to be levied by Energex and the network tariff structures of Ergon Distribution.

For large business customers, we must consider basing the N component on the Ergon Distribution network charges and tariff structures. We adopted this approach in previous price determinations.

Transitional arrangements

We are required to consider maintaining the transitional arrangements for tariffs classed as transitional or obsolete (for example, farming and irrigation tariffs). We are also required to consider allowing all customers in Ergon Distribution's distribution area to access tariffs designated as transitional in 2013–14.

Tariff trial

The 2018–19 delegation requires us to consider offering a voluntary trial tariff, based on the structure of any new cost-reflective residential network tariff submitted to the AER in Ergon Energy's 2018–19 Pricing Proposal. The delegation indicated that Ergon Energy would adjust rates to align with the UTP and long-run marginal cost pricing principles.

This is the first time we have been required to consider this issue.

Adjustments to the charges for standard contract customers

We are required to consider two adjustments to the charges for standard contract customers:

(a) allowing retailers to charge standard contract customers for amounts that are not included in the regulated retail tariff, in accordance with a program or scheme for the purchase of electricity from renewable or environmentally friendly sources

(b) allowing Ergon Energy Queensland Pty Ltd (Ergon Retail) to issue annual rewards to eligible customers that opt-in by agreeing to a series of requirements, consistent with Ergon Retail's Easy Pay Rewards scheme.

[24] Non-time-of-use tariffs are retail tariffs with usage charge rates that do not vary with the time and/or level of consumption.

[25] Tariff 91 applies to unmetered supplies (except street lighting).

[26] Time-of-use tariffs are retail tariffs with usage charge rates that vary with the time of consumption.

[27] Time-of-use demand tariffs are retail tariffs with usage and demand charge rates that vary with the time of consumption and/or demand.

This is the first time we have been required to consider these adjustments. The details of these government policies are outlined in the delegation and discussed in Chapter 6.[28]

[28] The 2018–19 delegation is included at Appendix A.

2 PRICING FRAMEWORK

The objects of the Electricity Act and the matters we are required to consider under the Electricity Act indicate that cost-reflective prices, and the promotion of retail competition are important guiding principles in making a price determination. Cost reflectivity is important for efficiency and equity reasons. The 2017–18 price determination was also designed to support retail competition in the large business customer segment in regional Queensland.

Under the Minister's delegation, we are also required to consider the UTP. The application of the UTP in previous price determinations has resulted in most notified prices being based on costs of supply which are below the actual costs of supply (see section 1.4).

Given that there is a degree of conflict between the matters we are required to consider under the Electricity Act and those we are required to consider under the Minister's delegation, we have considered a broad range of pricing approaches for 2018–19, particularly for the residential and small business customers (small customers) in Ergon Distribution's distribution area.

Our draft decision is to base notified prices for residential and small business customers in regional Queensland on the expected costs of supply in south east Queensland, plus a standing offer adjustment, and to continue to base notified prices for large business customers in regional Queensland on the lowest costs of supply in regional Queensland, which is Ergon Distribution's east pricing zone, transmission region one.

2.1 Residential and small business customers

In order to take into account the requirements of the Electricity Act and the UTP, we have considered a range of pricing approaches to setting the pricing framework for determining notified prices for small customers.

Cost build-up approach

The Minister's delegation requires us to consider an N+R cost build-up methodology when determining notified prices for 2018–19. Under this methodology, the N costs (network costs) are generally treated as a pass-through and the R costs (energy and retail costs) are determined by the QCA.

QCA position

Our draft decision is to continue estimating the costs of supply for each retail tariff using an N+R cost build-up approach, where we treat the N (network cost) component as a pass-through, and determine the R (energy and retail cost) component. This is consistent with the Minister's delegation and previous determinations.

Cost base

We also need to consider the appropriate costs of supply on which to base the notified prices for small customers. Three approaches have been considered.

We could maintain the approach we took in the 2017–18 price determination and base the notified prices on the costs of supply in south east Queensland (that is, costs in Energex's distribution area). As the costs of supply in south east Queensland are generally lower than those in regional Queensland, adopting this approach would result in customers continuing to pay prices that do not reflect their actual costs of supply. This would in turn potentially encourage inefficient investment and consumption, and require the ongoing subsidisation of electricity prices by taxpayers.[29] However, this approach may be considered appropriate as it would be consistent with the Queensland Government's definition of the UTP for 2018–19.

Another possible approach would be to base the notified prices for small customers on the lowest costs of supply in regional Queensland (that is, the costs in Ergon Distribution's east pricing zone, transmission region one). We have used this approach in setting notified prices for large business customers in regional Queensland since 2012.[30] Adopting this approach for small customers would improve the cost reflectivity of the notified prices, relative to setting prices based on the costs of supply in south east Queensland. It would also reduce the amount that taxpayers would pay to subsidise electricity prices in regional Queensland. However, it would be inconsistent with the Queensland Government's definition of the UTP for 2018–19, and may result in substantial price increases for customers. For example, based on estimates for 2017–18, the costs of supplying residential customers in Ergon Distribution's east pricing zone, transmission region one are 8.0 per cent higher than the costs of supplying customers of the same class in south east Queensland.[31]

A third approach would be to set the notified prices in each of the pricing regions in Ergon Distribution's distribution area at cost-reflective levels. This approach would promote retail competition and remove the need to subsidise regional electricity prices. However, it would be inconsistent with the UTP, as some small standard retail contract customers would, based on their geographic location, pay more for their electricity than small standard retail contract customers of the same class in other areas of Queensland. Cost-reflective prices would also result in substantial price increases, particularly for customers in western Queensland and those supplied by isolated systems. For example, based on estimates for 2017–18, the costs of supplying residential customers in Ergon Distribution's west pricing zone, transmission region one are 103 per cent higher than the costs of supplying customers of the same class in south east Queensland.[32]

Canegrowers Isis, Energy Queensland, the Queensland Council of Social Service (QCOSS) and the Queensland Consumers' Association supported the approach of basing the notified prices on the costs of supply in south east Queensland. The Chamber of Commerce and Industry Queensland (CCIQ) supported the principle of not penalising regional customers based on their geographic location, but did not view the current size of the subsidy as sustainable in the long term.[33] Cloncurry Shire Council was of the view that notified prices should incorporate Ergon east zone costs, to create a slight buffer to actual costs in south east Queensland and reduce the overall cost of the CSO to the State Government.[34]

QCA position

Our draft decision is to continue basing notified prices for residential and small business customers on the costs of supply in south east Queensland. We consider this decision

[29] The cost of this subsidy was expected to be $441.1 million in 2017–18 (as mentioned in section 1.4).

[30] We started using this approach for large business customers in regional Queensland when retail price regulation for large business customers in south east Queensland was discontinued.

[31] The cost estimates are based on a typical tariff 11 customer.

[32] The cost estimates are based on a typical tariff 11 customer.

[33] CCIQ, Submission to the QCA interim consultation paper, *Regulated Retail Electricity Prices for 2018–19*, 16 January 2018, p. 1.

[34] Cloncurry Shire Council, Submission to the QCA interim consultation paper, *Cloncurry Shire Council submission on electricity prices*, 15 January 2018, p. 1.

appropriate because it is consistent with the Queensland Government's UTP and it avoids the potentially large price increases associated with the other approaches.

Benchmark price level

To establish an appropriate benchmark price level for setting notified prices based on the costs of supply in south east Queensland, we have considered the Queensland Government's definition of the UTP, which is that notified prices for small customers in regional Queensland should broadly reflect the expected prices for small customers on standing offers in south east Queensland.[35] We have also considered the Queensland Government's view that the favourable terms and conditions associated with a standing offer be represented by a standing offer adjustment, set to the level in the QCA's 2017–18 regional pricing determination.

Customers on standing offers are supplied on the standard retail contract under the National Energy Customer Framework (NECF).[36] This contract contains standard terms and conditions. Customers who do not, or cannot, opt for a market contract are supplied by a standing offer by default.

A retailer can also offer market contracts that have different terms and conditions to standard retail contracts (for example, discounts on the bill if the customer pays early or pays by direct debit). While prices under market contracts are generally lower than standing offer prices, their terms and conditions often mean they offer less protections to customers.

In response to the ICP, CCIQ argued that:

> Due to recent directions by the Federal Government to retailers to move consumers onto market offers, or 'cheaper deals' to battle rising electricity prices, it would be inequitable to base notified prices on the standing offers in Queensland as a larger portion of consumers are on market offers. CCIQ advocates for the QCA to determine the median between the standing offer and average market offer to determine the notified price.[37]

Both QCOSS and the Queensland Consumers' Association were of the view that standing offer prices do not provide an accurate reflection of the costs of supply. The Queensland Consumers' Association argued that the QCA should only use the efficient costs of supply in south east Queensland when determining notified prices[38], while QCOSS suggested that the QCA consider other approaches for setting notified prices.[39]

QCA position

The QCA agrees with stakeholders' views that the standing offer price does not provide an accurate reflection of the costs of supply. However, the QCA regards the more favourable terms and conditions associated with standing offers compared to market offers as something that provides some level of value to customers. As a result, our draft decision is to determine notified prices for small customers in regional Queensland based on the expected costs of supply in south east Queensland, plus a standing offer adjustment to account for the more

[35] Covering letter to the delegation (Appendix A).

[36] See Schedule 1, National Energy Retail Rules.

[37] CCIQ, Submission to the QCA interim consultation paper, *Regulated Retail Electricity Prices for 2018–19*, 16 January 2018, p. 2.

[38] Queensland Consumers' Association, Submission to the QCA interim consultation paper, *Regulated Retail Electricity Prices 2018–19*, 15 January 2018, p. 2.

[39] QCOSS, Submission to the QCA interim consultation paper, *Regulated Retail Electricity Prices for 2018–19*, 18 January 2018, p. 2.

favourable terms and conditions associated with standing offers. We consider the standing offer adjustment in further detail in Chapter 6.

2.2 Large business customers

As noted above, in previous price determinations we have based notified prices for large business customers on the costs of supply in the lowest-cost area of regional Queensland (Ergon Distribution's east pricing zone, transmission region one). This approach has encouraged competition in the large business customer market in the east pricing zone, transmission region one. It is also consistent with the Queensland Government's definition of the UTP for 2017–18. However, this approach would not reflect the actual costs of supply in all regions, and would still require the Queensland Government to subsidise electricity prices.

Another approach would be to set fully cost-reflective notified prices. This would encourage competition in regional Queensland outside of the east pricing zone, transmission region one, and promote long-term efficient use of electricity services in regional Queensland in the large business customer market. However, it would introduce significant price increases for customers, especially customers in western Queensland and those supplied by isolated systems. We also consider this approach inconsistent with the Queensland Government's UTP for 2018–19.

Cloncurry Shire Council and Energy Queensland supported basing notified prices for large business customers on the costs of supply in Ergon Distribution's east pricing zone, transmission region one.[40] Canegrowers Isis was of the view that,

> Large business customers in South-East Energex area should not have a competitive advantage over Ergon customers as this will negatively impact and effectively stifle regional development and regional growth.[41]

QCA position

Our draft decision is to continue basing the notified prices for large business customers in regional Queensland on the lowest costs of supply in regional Queensland, which is Ergon Distribution's east pricing zone, transmission region one. We also propose to continue estimating the costs of supply for each retail tariff in accordance with an N+R cost build-up approach. This is consistent with our approach to setting notified prices for residential and small business customers, as discussed above. We consider the effect of our decisions on competition in the large business customer market in more detail in Chapter 6.

[40] Cloncurry Shire Council, Submission to the QCA interim consultation paper, *Cloncurry Shire Council submission on electricity prices*, 12 January 2018, p. 2.

[41] Canegrowers Isis, Submission to the QCA interim consultation paper, *Regulated Retail Electricity Prices for 2018–19*, 15 January 2018, p. 2.

3 NETWORK COSTS

A retailer incurs network costs when supplying electricity to its customers. These costs are associated with transporting electricity through the transmission and distribution networks and account for between 30 and 40 per cent of the final cost of electricity for small customers.

Powerlink, Energex Distribution (Energex) and Ergon Distribution, being regulated monopoly businesses, all earn regulated revenues that are determined by the AER. In addition to recovering their own distribution network costs, Energex and Ergon Distribution pass Powerlink's transmission network costs on to customers in network charges approved by the AER.

This chapter sets out the QCA's draft decisions on the network charges used as the basis of notified prices for 2018–19. Our draft decisions are largely consistent with the 2017–18 price determination. In summary, we have decided to:

- *base the flat rate retail tariffs and controlled load retail tariffs (tariffs 11, 20, 31 and 33) for residential and small business customers on Energex network tariff structures and charges*
- *base the seasonal time-of-use retail tariffs for residential and small business customers (tariffs 12A and 22A) on Ergon Distribution network tariff structures and Energex price levels*
- *base the seasonal time-of-use demand retail tariffs for residential and small business customers (tariffs 14 and 24) on Ergon Distribution network tariff structures and Energex price levels*
- *base the low voltage demand and unmetered supply (excluding street lighting) retail tariffs (tariffs 41 and 91) on Energex network tariff structures and charges*
- *base all retail tariffs for large business customers on Ergon Distribution network tariff structures and charges*
- *introduce tariff 15, as a voluntary trial tariff, based on Energex network tariff structures and charges*
- *ensure that Queensland customers in Essential Energy's distribution area have access to notified prices.*

3.1 Introduction

A retailer incurs network costs when electricity is supplied to its customers. Network costs are the costs associated with transporting electricity through transmission and distribution networks.

Under the network plus retail (N+R) cost build-up approach that the QCA uses to set notified prices, the network cost component is treated as a pass-through. However, to determine the amount of the network cost to be passed through to retail customers, we need to decide:

(a) the level at which network charges should be set (Energex or Ergon Distribution levels)

(b) the network tariff structure on which the network cost component should be based (Energex or Ergon Distribution tariff structures).

Network tariff structures can include, for example, combinations of fixed, usage and demand charges. Consistent with our previous price determinations, the network cost components of regulated retail tariffs are based on the network tariff structures and pricing provided by Energex and Ergon Distribution (distributors).

Network tariff structures and charges are established by distributors and approved by the AER. As the timing of our price determination does not fully align with the AER's network pricing review process, distributors have provided us with draft network prices.

Consequently, it is important to note that the draft network prices provided to the QCA are preliminary in nature and subject to change, as distributors will likely update their draft network prices prior to finalisation and submission to the AER in March 2018.

The network cost components for the final determination will be based on the network pricing submitted to the AER. In the event that the final network tariffs approved by the AER differ from those submitted by the distributors, the QCA will consider using a cost pass-through mechanism to adjust for any difference (see Chapter 6 for more information on this mechanism).

3.2 Network tariffs for residential, small business and unmetered supply customers

This section discusses the QCA's approach to setting network cost components of retail tariffs for residential, small business and unmetered supply customers, excluding street lighting customers (see section 1.3 for information on the network cost components for large and very large businesses, as well as street lighting retail tariffs).

For the 2018–19 price determination, the delegation requires that we consider:

- for residential and small business retail tariffs (tariffs 11, 20, 31, 33, 41 and 91, but not tariffs 12A, 14, 22A and 24), basing the network cost component on Energex network charges and tariff structures
- for residential and small business seasonal time-of-use retail tariffs (tariffs 12A and 22A) and time-of-use demand retail tariffs (tariffs 14 and 24), basing the network cost component on Energex network charges, but using the relevant Ergon Distribution network tariff structures.

Adopting the approach proposed in the delegation would be consistent with our approach in the 2017–18 determination. Under this approach, the network cost component of retail tariffs for small customers[42] would broadly reflect the costs of supplying small customers in south east Queensland, and would therefore be consistent with the UTP.[43]

3.2.1 Energex or Ergon Distribution network price levels

In determining the network cost components of small customer and unmetered supply[44] retail tariffs, the first issue the QCA must consider is the level at which network cost components should be set (Energex or Ergon Distribution price levels).

QCA position

As discussed in Chapter 2, the QCA's draft decision is to base notified prices for residential, small business and unmetered supply (excluding street lighting) customers on the cost of supply in south east Queensland. Consistent with this decision, we will set network cost components to

[42] Residential and small business customers.
[43] For more information on the Queensland Government's UTP, see Chapters 1 and 2.
[44] Unmetered supply retail tariff referred to in this chapter excludes street lighting–related services.

reflect Energex network price levels. Setting network cost components at Energex levels means that small customers in regional Queensland will generally pay the same for network services as small customers in south east Queensland.

3.2.2 Energex or Ergon Distribution network tariff structures

The second issue the QCA must consider is whether to adopt the network tariff structures of Energex or Ergon Distribution for small customer and unmetered supply retail tariffs.

Energex and Ergon Distribution offer a variety of network tariffs with different tariff structures for small customers, such as flat rate, time-of-use and time-of-use demand tariffs. Flat rate tariffs have a structure where the usage charge rates do not vary with the time and/or level of consumption. In contrast, time-of-use and time-of-use demand tariffs have a structure where the usage and demand charge rates vary with the time of use and/or demand.

Key differences between the Energex and Ergon Distribution network tariff structures for small customers include:

- the proportion of costs recovered through fixed charges
- the approach to usage charge rates (for example, flat usage rates versus three-part inclining block tariffs)
- the applicable time-of-use and demand charging periods (for example, different peak and off-peak periods)
- the methodology for calculating demand charges.

See Appendix D for further information on differences between the network tariff structures.

Flat rate and controlled load retail tariffs

The delegation directs us to consider adopting Energex network tariff structures for the residential and small business flat rate retail tariffs (tariffs 11 and 20) and controlled load tariffs (tariffs 31 and 33).

Canegrowers submitted that the application of the N+R framework in past determinations by the QCA is flawed. It said that '*…many of the costs in the Energex area do not apply in the Ergon area*'.[45] It considered energy costs to be an example of this, with Energex's 'peakier' load profile leading to higher prices than in Ergon Distribution's distribution area. Canegrowers also considered that previous decisions had loaded Ergon customers with costs that did not exist in Ergon Distribution's distribution area, in order to reduce the cost of the UTP to the government. It considered that this did not promote competition in the Queensland retail electricity market or set a framework for the electricity industry that would promote efficient, economical and environmentally sound supply and use. Canegrowers implied that notified prices for customers in Ergon Distribution's distribution area should align more with Ergon Distribution's network costs.

CCIQ also considered the N+R methodology applied in past determinations by the QCA to be flawed. It noted that the consumer profile in the Energex distribution area is vastly different to the profile in Ergon Distribution's distribution area and has a different demand and supply ratio as well. However, the CCIQ also acknowledged *'the efforts QCA undertakes to mitigate these*

[45] Canegrowers, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 19 January 2018, p. 1.

flaws where possible in the methodology calculations and the restraints due to the UTP'.[46] It encouraged the QCA to '*use a lowest cost model methodology to put downward pressure on regional electricity prices for all users*'.[47]

Energy Queensland recognised the requirement to calibrate network tariffs for notified prices to Energex's revenue metric under the UTP as contemplated for 2018–19, and supported the use of Energex's network tariff structures as the basis for flat rate tariffs for residential, small business and unmetered supply (excluding street lighting) customers.[48]

While there may be region-specific differences between the costs in Energex and Ergon Distribution's distribution areas, the 2018–19 delegation is specific in its intent for us to consider basing the N component of notified prices on the costs in the Energex distribution area. Adopting a completely cost-reflective approach to determining network costs, as proposed in Canegrowers' submission, would not achieve the objectives of the UTP or be consistent with the 2018–19 delegation.

We consider it appropriate to continue to base residential and small business flat rate retail tariffs and controlled load tariffs on Energex network tariff structures.

Time-of-use and time-of-use demand retail tariffs

For residential and small business seasonal time-of-use retail tariffs (tariffs 12A and 22A) and time-of-use demand retail tariffs (tariffs 14 and 24), we have been directed to consider adopting Ergon Distribution network tariff structures.

We consider that using Ergon Distribution network tariff structures for the seasonal time-of-use and time-of-use demand retail tariffs would be more cost-reflective than using Energex network tariff structures.

Furthermore, we consider that it is more important that the seasonal time-of-use and time-of-use demand retail tariffs reflect Ergon Distribution network tariff structures, as these retail tariffs send signals to customers about those network costs that retailers incur due to the time and/or level of electricity usage and demand.

As noted by the AER, time-of-use and demand tariffs are generally more cost-reflective than flat rate and inclining block tariffs.[49] The delegation[50] also points out that using Ergon Distribution network tariff structures for seasonal time-of-use and time-of-use demand retail tariffs would enhance the underlying network price signals and therefore encourage customers to reduce usage during peak periods on Ergon Distribution's network.

A number of stakeholders' comments above about flat rate and controlled load retail tariffs also apply to time-of-use and time-of-use demand retail tariffs.

Canegrowers Isis considered that Ergon's tariff structures would be more suitable, as it would encourage users to work towards cost reflectivity. It suggested that if Ergon's time-of-use network tariff structures are used as a basis for Energex's pricing, notified prices would deliver a

[46] CCIQ, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 16 January 2018, p. 2.
[47] CCIQ, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 16 January 2018, p. 2.
[48] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 January 2018.
[49] AER, *Tariff Structure Statement Proposal*: *Energex* & *Ergon Energy*, draft decision, August 2016.
[50] The 2018–19 delegation is included in Appendix A, p. 2.

viable solution for both regional irrigators and Ergon. Such a structure would accommodate different peak demand periods while sending the appropriate pricing signal via the tariff structure. Energy Queensland supported the use of Ergon Energy's network tariff structures for tariffs 12A, 14, 22A and 24.[51]

We propose to base residential and small business seasonal time-of-use and time-of-use demand retail tariffs on Ergon Distribution network tariff structures.

Trial tariff

The 2018–19 delegation raised a number of new matters for the QCA to consider. One of those is a voluntary trial tariff based on the structure of any new cost-reflective residential network tariff that is submitted by Ergon Energy to the AER in its 2018–19 pricing proposal.

The smart meter trial tariff Ergon has proposed, a residential lifestyle tariff (tariff 15 or T15), is based on Energex's draft network tariff 6400. Tariff 15 consists of three rates:

- a variable rate paid per kWh (2.954 cents/kWh, applied to total annual consumption)
- a monthly fixed charge (which varies depending on which peak summer window (PSW) consumption 'band' customers nominate) ($/month, see below)
- a 'top-up' rate ($3.600/kWh/summer month).

The top-up rate is applied on the maximum consumption above the daily PSW band limit within that month. The top-up rate is applied when customers consume beyond their PSW band limit (see below) on any day between November and March[52], or have selected the pay-as-you-go option (band 1). The top-up rate only applies to the month in which maximum consumption is higher than the PSW band limit.

Ergon Distribution considers the benefits of this tariff are that it will allow consumers to smooth and control the network element of their electricity bill. The cost of using the network is primarily linked to customer usage of the network between 4 pm and 9 pm in the summer season of November to March (i.e. the PSW).

The proposed bands are:

- Band 1: $24.270 per month (0 kWh cap on daily usage during the PSW included)
- Band 2: $31.090 per month (5 kWh cap on daily usage during the PSW included)
- Band 3: $37.910 per month (10 kWh cap on daily usage during the PSW included)
- Band 4: $44.730 per month (15 kWh cap on daily usage during the PSW included)
- Band 5: $55.550 per month (20 kWh cap on daily usage during the PSW included).

Tariff 15 reduces the variable rate (which applies to all usage, all the time, all year) and allows customers to effectively set their own network charge (which is fulfilling a similar purpose to the fixed charge in T11), by determining what their maximum demand will be during the peak summer window. It is then up to customers to manage their electricity usage within that band, or pay the top-up rate.

[51] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19,* 31 January 2018.

[52] For example, if your PSW band limit is 5 kWh, and on one day in December you consumed 6 kWh, you would pay an additional $7.713 in December.

As in previous situations, access to the T15 trial will most likely be at the discretion of Ergon Retail and Ergon Distribution. To participate in the trial, customers will require a smart meter, which may incur installation and ongoing operational costs.

Customer impact

The impact of T15 on customers, compared to T11, will depend on annual consumption, PSW consumption, whether consumers remain within their nominated band limit and their use of controlled load tariffs. Customers with low PSW consumption levels but high overall consumption will see the largest proportional reduction in their bill. Conversely, this style of tariff would be least attractive to customers with low total consumption but high, inelastic demand during the PSW.

An additional cost of T15 will be increased metering charges for customers who do not already have smart meters (see Chapter 5).

Another potential impact on possible benefits to customers is whether accessing T15 will change their ability to access controlled load tariffs (T31 and T33). We have not received information from Ergon Retail yet as to whether restrictions will be introduced or changes made to current policy. If customers are unable to continue to access controlled load tariffs, or if access to T31 and T33 is replaced by access to an (as yet unknown) alternative controlled load tariff, then the potential benefits (see Table 3 below) may not reflect customers' actual circumstances.

Table 3 shows the potential savings for customers on T15, compared to T11—if they stay within their nominated PSW consumption band limit. If PSW consumption exceeds the band limit, then customers could see less savings or even pay more than they would have paid on T11.

However, the analysis in Table 3 suggests that T15 has the potential to benefit customers, provided they:

- use controlled load tariffs (T31 and T33) as before
- understand the times the PSW applies
- can monitor and manage their consumption during the PSW
- have an idea of their total annual consumption.

Table 3 Possible benefits of T15, compared to T11 (% of T11 bill/year)

	Peak Summer Window consumption cap applied each day (kWh/PSW/per day)				
kWh/year	***2.5***	***5***	***10***	***15***	***20***
2,000	-12%	-17%	-27%	-37%	-47%
2,500	-7%	-12%	-20%	-29%	-38%
3,000	-3%	-7%	-15%	-23%	-31%
3,500	0%	-4%	-11%	-18%	-25%
4,000	2%	-1%	-8%	-14%	-20%
4,500	4%	1%	-5%	-11%	-16%
5,000	6%	3%	-2%	-8%	-13%
5,500	7%	5%	0%	-5%	-10%
6,000	8%	6%	1%	-3%	-8%
6,500	9%	7%	3%	-1%	-6%
7,000	10%	8%	4%	0%	-4%
7,500	11%	9%	5%	2%	-2%
8,000	12%	10%	7%	3%	-1%
8,500	13%	11%	8%	4%	1%
9,000	13%	12%	8%	5%	2%
9,500	14%	12%	9%	6%	3%
10,000	14%	13%	10%	7%	4%

a. Peak Summer Window (PSW) is between 4 pm and 9 pm in the summer season of November to March. Customers' maximum usage each month determines what monthly charge they incur between November and March.

b. Table 3 includes the metering charges proposed in Chapter 5.

Energy Queensland supported the introduction of new voluntary trial tariffs, and for those trial tariffs to be gazetted and included in notified prices. It was of the view that:

> in setting the notified prices for the cost reflective trial tariffs, the integrity of Ergon Energy's long run marginal cost (LRMC) signal should be preserved and not be based on Energex's LRMC. By calibrating the tariff elements used to recover the residual costs, compliance with the UTP obligation would be achieved at an overall tariff level. Such an approach would ensure that the integrity of Ergon Energy's economically efficient tariffs would be preserved while meeting the UTP requirement.[53]

The Queensland Consumers' Association also supported the introduction of new voluntary trial tariffs.[54]

[53] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 January 2017, p. 5.

[54] Queensland Consumers' Association, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 January 2017, p. 5.

QCOSS supported trials as an approach to the development of fair and equitable tariffs, but could not support the introduction of a particular voluntary trial tariff without knowing what the structure would be. It made several suggestions:

- To avoid bias, trials must include a broad cross-section of the community, rather than just early adopters.[55]
- Network businesses should share the results of trials so there is effective and efficient learning across Australia.
- Participants should not be worse off, and should be compensated for any detriment. This includes compensation for any new meter costs that may have to be paid upfront due to a tariff change.
- The trial should extend for at least a year to take seasonal effects into account.
- Trials should address consumer-specific criteria such as bill stability, and simplicity/ease of understanding.
- Ergon should consult on how its trial is to be designed, and on how it intends to recruit customers to participate in the trial.

QCOSS offered to assist Ergon in identifying and obtaining the relevant customer segments that should be included in a trial—for example, low-income, aged, disabled, Indigenous, and culturally and linguistically diverse communities.[56]

We note that QCOSS was unable to comment on the structure and level of T15, as the information was not available when the ICP was released. A number of QCOSS's suggestions relate to Ergon Retail's implementation of a trial tariff (as opposed to the structure or level).

Based on the information provided thus far, we do not oppose the trial of the proposed T15. The pace of change and increasing uncertainty in the Australian electricity sector over the past 12 months has highlighted that all market participants, including consumers, need to engage differently in electricity markets. The T15 trial will explore a different framework for recovering network costs, with an emphasis on managing peak demand. If successful, it could deliver network costs savings to all consumers in future network pricing proposals.

However, we caution consumers about the risk of 'trialling' any tariff without having a clear understanding of both how the cost components of the tariff work, and of consumers' individual exposure to increased costs. We note the risk of household consumption being above the PSW band limit they choose, and suggest that consumers inform themselves about their average and maximum consumption during the PSW, and think carefully about how flexible they can be when using electricity to make sure they stay within the limit of their PSW band, before committing to a trial.

[55] Early adopters are likely to be households who have a high level of understanding of the trial. They will be aware either that their energy use profile is flat and that the tariff will benefit them, or that they are able to make the required behaviour changes to reduce their peak demand on the network. The trial is unlikely to include consumers who have low income or are at risk of vulnerability. It is important that a trial includes a broad cross-section of the community to ensure that findings reflect the impact that may be felt across the community, particularly for those who are most at risk of experiencing vulnerability in the energy market.

[56] QCOSS, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 18 January 2017.

Unmetered supply (excluding street lighting) retail tariff

Consistent with the 2017–18 price determination, we propose to base retail tariff 91 (unmetered supply) on the relevant Energex network tariff structures.

Low voltage demand retail tariff

Tariff 41 is a low voltage demand retail tariff available to small business customers in regional Queensland. It has fixed, usage and demand charges and is based on an Energex network tariff (network tariff code: 8300). Ergon Distribution does not have an equivalent network tariff available for small customers.

While Energex designates network tariff 8300 as a large business customer network tariff, it is made available to small business customers on a voluntary basis. In the 2017–18 price determination, we decided to retain tariff 41, on the basis that small business customers in south east Queensland would have access to this Energex network tariff.

For the same reason, for 2018–19 we propose to retain tariff 41 and continue basing it on the relevant Energex network tariff structure.

QCA position

The QCA's draft decision is to use:

- Energex network tariff structures as the basis for setting the network cost components of flat rate, controlled load, unmetered supply and low voltage demand retail tariffs (tariffs 11, 20, 31, 33, 41 and 91)
- Ergon Distribution network tariff structures as the basis for setting the network cost components of seasonal time-of-use and time-of-use demand retail tariffs (tariffs 12A, 22A, 14 and 24).

We have also decided to include Ergon Retail's proposed trial tariff (T15) in notified prices for 2018–19, in order to facilitate customer trials.

3.2.3 Adjusting network charges towards Energex price levels while retaining Ergon Distribution tariff structures

As discussed, the QCA's draft decision is to use Ergon Distribution network tariff structures as the basis for setting seasonal time-of-use and time-of-use demand retail tariffs for residential and small business customers, while reducing the network cost components to Energex price levels.

Consistent with the 2017–18 price determination, the QCA has adopted different adjustment approaches for the four tariffs[57] to:

- prevent our adjustments resulting in adjusted network prices being set higher than the levels that may be approved by the AER
- preserve the relativities between different pricing components within a network tariff, to the greatest extent possible.

To adjust the network cost components towards Energex price levels, we propose using the same adjustment approach as in the 2017–18 determination. This involves adjusting:

[57] Tariffs 12A, 22A, 14 and 24.

- the residential seasonal time-of-use retail tariff (tariff 12A) by adopting Ergon Distribution usage cost components, and reducing the Ergon Distribution fixed cost component towards Energex price levels. As a result, the overall level of network cost components has been reduced to a level where regional residential customers will, on average, pay the same as they would on a residential flat rate tariff in south east Queensland.
- the small business seasonal time-of-use retail tariff (tariff 22A) by adopting the Energex fixed cost component, and reducing Ergon Distribution usage cost components towards Energex price levels. As a result, the overall level of network cost components has been reduced to a level where regional small business customers will, on average, pay the same as they would on a small business flat rate tariff in south east Queensland.
- the residential and small business seasonal time-of-use demand tariffs (tariffs 14 and 24) by uniformly decreasing the Ergon Distribution fixed, usage and demand cost components towards Energex price levels. As a result, the overall level of network cost components has been reduced to a level where regional residential or small business customers will, on average, pay the same as they would on a residential or small business flat rate tariff (respectively) in south east Queensland. Appendix D provides more information on the adjustment approaches.

Ergon Retail's proposed trial tariff (T15) is based on Energex's proposed network tariff 6400.

QCA position

The QCA's draft decision is to adjust:

- the residential seasonal time-of-use retail tariff (tariff 12A) by adopting Ergon Distribution usage cost components, and reducing the Ergon Distribution fixed cost component towards Energex price levels
- the small business seasonal time-of-use retail tariff (tariff 22A) by adopting the Energex fixed cost component, and reducing Ergon Distribution usage cost components towards Energex price levels
- the residential and small business seasonal time-of-use demand tariffs (tariffs 14 and 24) by uniformly decreasing the Ergon Distribution fixed, usage and demand cost components towards Energex price levels.

Ergon Retail's proposed T15 is built on network costs that are identical in both Energex and Ergon Distributions' distribution areas. As a result, no adjustments to the cost components are required.

3.2.4 Essential Energy network customers

The cover letter to the 2018–19 delegation requires us to consider:

> Clarifying the arrangements for regional Queensland customers on Essential Energy's network to ensure they receive the same price protections as other regional customers under the UTP.[58]

As noted in Chapter 1, customers in Essential Energy's distribution area in southern Queensland do not currently have access to notified prices. Origin Energy receives a subsidy to ensure that non-market customers in that distribution area pay no more than similar customers that have access to notified prices.

[58] The cover letter to the 2018–19 delegation is included in Appendix A.

In the ICP, we noted that the Minister had sought this clarification. Most stakeholders did not address the issue in their submissions.

Origin Energy supported continuing the approach adopted by the QCA from the 2017–18 price determination, but did not mention the arrangements for Queensland customers on Essential Energy's network.[59]

QCA position

Consistent with the UTP and the cover letter to the 2018–19 delegation, we have determined that 2018–19 notified prices should be made available to Queensland customers in Essential Energy's distribution area.

3.2.5 Network cost components for 2018–19

The QCA's draft decision is to base regulated retail tariffs for residential, small business and unmetered supply customers on:

- Energex network tariff structures and cost components for retail tariffs 11, 20, 31, 33, 41 and 91
- Ergon Distribution network tariff structures and adjusted cost components for retail tariffs 12A, 22A, 14 and 24. To maintain consistency with the UTP, the level of network cost components has been adjusted to a level where regional customers will, on average, pay the same as they would pay on flat rate tariffs in south east Queensland.

Our draft decisions on the network tariff structures and charges to apply to each retail tariff are presented in the following tables. As discussed in section 3.1, it is important to note that these tables are based on draft network tariffs and charges and therefore may be revised for the final determination.

Table 4 Energex network charges for 2018–19 for retail tariffs 11, 20, 31, 33, 41 and 91 (GST exclusive), draft decision

Retail tariff	*Energex network tariff code*	*Fixed charge [a] c/day*	*Usage charge c/kWh*	*Demand charge $/kW/mth*
Tariff 11—Residential (flat rate)	8400	47.900	8.457	
Tariff 20—Business (flat rate)	8500	65.100	9.123	
Tariff 31—Night rate (super economy)	9000		5.741	
Tariff 33—Controlled supply (economy)	9100		6.991	
Tariff 41—Low voltage (demand, obsolete) [b]	8300	451.600	0.399	20.047
Tariff 91— Unmetered	9600		7.290	

a *Charged per metering point.*

b *The kVA equivalent demand charge for tariff 41 is $18.197/kVA/month. A conversion factor of 0.9077 has been used, as advised by Energex.*

[59] Origin Energy, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 15 January 2017.

Table 5 Calculated network charges for 2018–19 for retail tariffs 12A, 14, 22A and 24 (GST exclusive), draft decision

Retail tariff	*Fixed charge [a] c/day*	*Usage charge (peak) c/kWh*	*Usage charge (off-peak or flat) c/kWh*	*Demand charge (peak) $/kW/mth*	*Demand charge (off-peak) $/kW/mth*
Tariff 12A—Residential (seasonal time-of-use)	36.329	40.498	5.241		
Tariff 22A—Business (seasonal time-of-use)	65.100	31.417	6.214		
Tariff 14—Residential (seasonal time-of-use)	6.948		1.893	53.743	7.911
Tariff 24—Business (seasonal time-of-use)	7.911		2.676	76.049	7.833

a *Charged per metering point.*

Table 6 Calculated network charges for 2018–19 for trial retail tariff 15 (GST exclusive), draft decision

Retail tariff	*Energex network tariff code*	*Fixed Charge (Band 1)[a] $/mth*	*Fixed Charge (Band 2)[b] $/mth*	*Fixed Charge (Band 3)[c] $/mth*	*Fixed Charge (Band 4)[d] $/mth*	*Fixed Charge (Band 5)[e] $/mth*	*Usage charge c/kWh*	*Top-up charge[f] $/kWh/mth*
Tariff 15—Residential lifestyle	6400	24.270	31.090	37.910	44.730	51.550	2.954	3.600

a *Band 1 (no peak summer window (PSW) allowance, where PSW refers to the time period of 4pm-9pm during months November to March).*

b *Band 2 (up to 5 kWh PSW allowance included).*

c *Band 3 (up to 10 kWh PSW allowance included).*

d *Band 4 up to 15 kWh PSW allowance included).*

e *Band 5 (up to 20 kWh PSW allowance included).*

f *The top up charge only applies to consumption that exceeds the peak summer window consumption cap for the given fixed charge band. Once exceeded, the cap is extended for the month, equal to the new increased peak consumption value and is then reset to the original cap at the start of the next peak month.*

3.3 Network tariffs for large business, very large business and street lighting customers

For the 2017–18 price determination, the QCA based retail tariffs for large[60] and very large[61] business customers, as well as for street lighting customers, on the network tariffs and charges applicable in Ergon Distribution's east pricing zone, transmission region one. We propose to

[60] Large business customers are Standard Asset Customers (SACs) (large), typically consuming more than 100 MWh but less than 4 GWh per annum.

[61] Very large business customers consist of Connection Asset Customers (CACs), typically consuming more than 4 GWh but less than 40 GWh per annum and Individually Calculated Customers (ICCs), typically consuming more than 40 GWh per annum.

continue with this approach for 2018–19, as it is consistent with our draft decision, discussed in Chapter 2, to set notified prices for these customers based on the lowest costs of supply in regional Queensland.

3.3.1 High voltage retail tariffs—tariffs 47 and 48

In our 2017–18 price determination, the QCA introduced seven high voltage retail tariffs for Connection Asset Customers (CACs) (tariffs 51A, 51B, 51C, 51D, 52A, 52B and 52C) and one high voltage retail tariff for Individually Calculated Customers (ICCs) (tariff 53). The CAC tariffs were underpinned by Ergon Distribution CAC standard network tariffs and CAC seasonal time-of-use demand (STOUD) network tariffs, and the ICC tariff by the Ergon Distribution CAC standard network tariff high voltage line (HVL).

The four CAC standard network tariffs have six charging components:[62]

- an actual demand charge ($/kVA/month), which applies to the customer's actual kVA monthly maximum demand
- an excess reactive power charge ($/excess kVAr/month), which applies to the kVAr used by a customer that exceeds the customer’s permissible quantity[63]
- a capacity charge ($/kVA of authorised demand/month), which applies to the customer’s individual kVA authorised demand or, if there is no authorised demand, the annual maximum demand in the previous full pricing period prior to the setting of prices
- a fixed charge ($/day)
- a connection unit charge ($/day/connection unit)
- an any time energy charge ($/kWh of total energy consumed).

The three CAC STOUD network tariffs have seven charging components:[64]

- a peak demand charge ($/kVA/month), which applies to the customer's maximum kVA demand recorded between 10 am to 8 pm during summer weekdays[65]
- an excess reactive power charge ($/excess kVAr/month), which applies to the kVAr used by a customer that exceeds the customer’s permissible quantity[66]
- a capacity charge ($/kVA of authorised demand/month), which applies to the greater of either the customer’s authorised demand or the actual monthly half hour maximum demand[67]
- a fixed charge ($/day)
- a connection unit charge ($/day/connection unit)

[62] The network charging components consist of both the distribution use of system charges and transmission use of system charges.
[63] A customer's permissible kVAr quantity is determined by the customer’s authorised demand and the NER-compliant power factor.
[64] The network charging components consist of both the distribution use of system charges and transmission use of system charges.
[65] Summer months are December, January and February.
[66] A customer's permissible kVAr quantity is determined by the customer’s authorised demand and the National Electricity Rules' compliant power factor.
[67] The monthly actual maximum demand is measured all year excluding summer peak demand window times (i.e. 10 am to 8 pm during summer weekdays).

- peak energy charge ($/kWh of energy consumed), which applies to the total energy consumed during summer months[68]
- off-peak energy charge ($/kWh of energy consumed), which applies to the total energy consumed during non-summer months.[69]

The accessibility of these network tariffs is determined by the customer's connection voltage. More information on Ergon Distribution's network tariffs is available on the Ergon website.[70]

The 2018–19 delegation requires that for large and very large business customers who consume 1,000 MWh or more each year we consider basing the network cost component on the network charges to be levied by Ergon Distribution.

In the ICP, we sought customer feedback as to whether we should use Ergon Distribution's network tariffs as the basis for retail tariffs for large and very large business customers and street lighting customers.

Energy Queensland considered that the 2017–18 approach of basing regulated retail tariffs for large business customers on Ergon Energy's network tariffs should be maintained.[71] Cloncurry Shire Council also supported this approach (basing the network charge on Ergon Eastern standard costs), and noted that it would create a slight buffer to actual costs in south east Queensland—reducing the overall cost of the CSO to the State Government.[72]

Canegrowers Isis submitted that the QCA should use the Ergon tariff structure for large customers, but that Energex prices should be applied as per small customers.[73]

Considerations

Energy Queensland has advised that among the non-site specific network tariffs, the CAC standard network tariff HVL (HVL-22/kV line) is still the closest to cost reflectivity for ICCs on a network level. Therefore, we should continue to base the ICC retail tariff on the CAC standard network tariff HVL.

We also note that applying Energex prices would be inconsistent with the 2018–19 delegation. Furthermore, an increasing number of large and very large customers in Ergon Distribution's distribution area have already transitioned from notified prices to market offers (see Chapter 6). Changing the baseline that has underpinned the electricity market in Ergon Distribution's distribution area could disadvantage businesses and retailers.

Continuing to base tariffs for large and very large customers on Ergon Distribution's east pricing zone, transmission region one network costs also means that market customers in the east pricing zone, transmission region one are on cost-reflective tariffs. This is consistent with the matters the QCA is required to consider under the Electricity Act, and also with the objects of the Electricity Act (see Chapter 1).

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[68] Summer months are December, January and February.
[69] Non-summer months are March to November.
[70] https://www.ergon.com.au/network/network-management
[71] Energy Queensland, Submission on the QCA Interim Consultation Paper, *Regulated retail electricity prices for 2018–19*, 31 January 2018.
[72] Cloncurry Shire Council, Submission on the QCA Interim Consultation Paper, *Regulated retail electricity prices for 2018–19*, 15 January 2018.
[73] Canegrowers Isis, Submission on the QCA Interim Consultation Paper, *Regulated retail electricity prices for 2018–19*, 12 January 2018.

QCA position

On the basis of this analysis, and given the matters the QCA is required to consider, we propose to maintain the tariffs introduced in 2017–18, underpinned by the Ergon Distribution CAC standard network tariffs, CAC seasonal time-of-use demand (STOUD) network tariffs and CAC standard network tariff HVL.

3.3.2 Network cost components for 2018–19

The QCA's draft decision is to continue to base retail tariffs for large and very large business customers and street lighting customers on the network tariffs applying to Ergon Distribution’s east pricing zone, transmission region one.

Our draft decision on the network tariff structures and charges to apply to each retail tariff is presented in the following tables. As discussed, it is important to note that these tables are based on draft network tariffs and charges, which may be revised for the final determination.

Table 7 Ergon Distribution network charges for 2018–19 large business and street lighting customer retail tariffs (GST exclusive), draft decision

Retail tariff	***Ergon Distribution network tariff code***	***Fixed charge[a] c/day***	***Usage charge (peak) c/kWh***	***Usage charge (off-peak/flat) c/kWh***	***Demand charge (peak) $/kW/mth***	***Demand charge (off-peak/ flat) $/kW/mth***
Tariff 44—Over 100 MWh small (demand)	EDSTT1	3878.900		1.361		32.937
Tariff 45—Over 100 MWh medium (demand)	EDMTT1	13612.800		1.361		24.937
Tariff 46—Over 100 MWh large (demand)	EDLTT1	35502.400		1.339		20.228
Tariff 50—Seasonal time-of-use (demand)	ESTOUDCT1	3077.900	1.041	3.291	58.583	10.532
Tariff 71—Street lighting[b]	EVUT1	0.400		16.253		

a *Charged per metering point.*

b *The fixed charge for street lighting applies to each lamp.*

Table 8 Ergon Distribution network charges for 2018–19 very large business customer retail tariffs (GST exclusive), draft decision

Retail tariff	*Ergon Distribution network tariff code*	*Fixed charge c/day*	*Usage charge (peak) c/kWh*	*Usage charge (off-peak or flat) c/kWh*	*Connection unit charge $/day/unit*	*Capacity charge (off-peak/flat) $/kVA of authorised demand/mth*	*Demand charge (peak/flat) $/kVA/mth*	*Excess reactive power charge $/excess/kVAr/mth*
Tariff 51A—Over 4 GWh high voltage (CAC 66kV)	EC66T1	21289.400		1.356	9.075	4.178	2.475	4.000
Tariff 51B—Over 4 GWh high voltage (CAC 33kV)	EC33T1	14594.400		1.356	9.075	4.994	2.475	4.000
Tariff 51C—Over 4 GWh high voltage (CAC 22/11kV Bus)	EC22BT1	13152.400		1.359	9.075	5.744	3.069	4.000
Tariff 51D—Over 4 GWh high voltage (CAC 22/11kV Line)	EC22LT1	12328.400		1.374	9.075	11.189	6.081	4.000
Tariff 52A—Over 4 GWh high voltage (CAC STOUD 33/66kV)	EC66TOUT1	8929.400	0.966	1.326	9.075	6.095	11.000	4.000
Tariff 52B—Over 4 GWh high voltage (CAC STOUD 22/11kV Bus)	EC22BTOUT1	8929.400	0.969	1.329	9.075	4.295	40.427	4.000
Tariff 52C—Over 4 GWh high voltage (CAC STOUD 22/11kV Line)	EC22LTOUT1	8929.400	0.984	1.344	9.075	7.895	72.333	4.000
Tariff 53—Over 40 GWh high voltage (ICC)[a]	EC22LT1	12328.400		1.374		11.189	6.081	4.000

a *Ergon Distribution advised that ICCs do not incur connection unit charges on a network level.*

4 ENERGY COSTS

A retailer incurs energy costs when purchasing electricity to meet the electricity demand of its customers. Energy costs can be separated into three general components:

- *wholesale energy costs*
- *other energy costs*
- *energy losses.*

As with previous price determinations, the QCA has determined energy costs based on advice from ACIL Allen, its consultant. Energy costs are estimated to:

- *decrease for customers on the Energex and Ergon net system load profiles*
- *increase for customers on the Energex controlled load profiles.*

This chapter gives an overview of how each of the three energy cost components was estimated. A more detailed explanation is available in ACIL Allen's 2018–19 draft report.[74] *Issues about energy cost that were raised in submissions are addressed in chapter 3 of ACIL Allen's draft report.*

4.1 Wholesale energy costs

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) to meet the electricity demand of its customers. The NEM is a volatile market where spot prices are settled every half an hour and currently can range from –$1000 per megawatt hour (MWh) to $14,200 per MWh.[75]

Retailers can, and do, adopt a range of strategies to reduce spot price volatility risk, including:

- pursuing a hedging strategy by purchasing financial derivatives[76]—such as futures, swaps, caps and options
- entering long-term power purchase agreements with generators
- investing in their own electricity generators.

Since the 2012–13 price determination, ACIL Allen has estimated wholesale energy costs for customers on notified prices using a market hedging approach, which takes into account retailers' hedging strategies. Such an approach has also been adopted by other Australian regulators[77] to estimate energy costs and has been endorsed by the Australian Energy Market Commission (AEMC) in its 2013 advice on best practice retail regulation.[78]

[74] ACIL Allen Consulting, *Estimated Energy Costs, 2018–19 Retail Tariffs*, prepared for the QCA, February 2018, available at http://www.qca.org.au/Electricity/Regional-consumers/Reg-Electricity-Prices.

[75] The minimum spot price (market floor price) and the maximum spot price (market price cap) are defined in chapter 3 of the National Electricity Rules. The market price cap is published by the AEMC every February and is effective from 1 July. For more information, see www.aemc.gov.au.

[76] Generally, purchasing financial derivatives enables retailers to lock in a price, or a maximum price (in the case of caps) at which electricity will be exchanged at a future date.

[77] The Independent Competition and Regulatory Commission and the Office of the Tasmanian Economic Regulator.

[78] AEMC, *Advice on best practice retail price methodology*, final report, 27 September 2013.

For the 2018–19 price determination, we have again engaged ACIL Allen to estimate wholesale energy costs for customers on:

- the net system load profiles (NSLPs) in the Energex and Ergon distribution areas
- the controlled load profiles (CLPs) in the Energex distribution area.

The NSLP and CLP approximate how much electricity is consumed by customers on accumulation meters[79] in a region, for each half hour of the day. At this stage, the majority of customers in Queensland are on accumulation meters. There are currently two types of CLPs in the Energex distribution area—CLP 9000 and CLP 9100—which capture the consumption profiles of customers on retail tariffs 31 and 33 respectively.

In its submission to the QCA, Energy Queensland[80] supported using a market hedging approach to estimate wholesale energy costs. However, it noted that a long-run marginal cost (LRMC) approach should be considered in future determinations, as more retailers enter long-term power purchase agreements to finance new renewable energy projects.

As set out in its draft report on estimated energy costs for 2018–19 (2018–19 draft report), ACIL Allen has continued to estimate wholesale energy costs using a market hedging approach. This approach is designed to simulate the wholesale energy market from a retailer's perspective. It involves simulating expected spot prices, and a retailer that hedges spot price risk by purchasing financial derivatives with contract prices represented by the observable ASX Energy futures[81] market data. A detailed explanation of how wholesale energy costs were estimated is available in chapter 4 of ACIL Allen's 2018–19 draft report.

Compared to the estimates for the 2017–18 price determination, ACIL Allen estimated that wholesale energy costs for 2018–19 will:

- **decrease** for customers on the **Energex NSLP** and **Ergon NSLP**. This decrease reflects the projected decrease in spot price volatility in Queensland and other NEM regions resulting from the expected entry of approximately 5000 MW of utility-scale solar and wind generation into the NEM. Of the 5000 MW new capacity, 1800 MW is committed to enter the Queensland market. ACIL Allen also attributed the projected decrease in price volatility to the Queensland Government's directive to Stanwell in June 2017, where Stanwell was directed to adjust its bidding behaviour to put downward pressure on spot prices.
- **increase** for customers on the **Energex CLPs**. This increase reflects an increase in base contract prices of 2018–19 relative to 2017–18 (see section 4.1.2). More electricity is consumed during off-peak periods under the CLPs than the NSLPs (see section 4.1.1) and, consequently, more base contracts were required to hedge the CLPs. This means that, all other things being equal, the increase in base contract prices has a more substantial impact on the CLPs than the NSLPs, leading to higher wholesale energy estimates for the CLPs.

[79] Unlike smart/digital meters, accumulation meters do not record when during the day electricity was consumed or how much was consumed at that time. To allow for half-hourly settlement within the NEM (with different spot prices and volume for each half hour), AEMO uses the NSLP to approximate the amount of electricity consumed by customers on accumulation meters in a region, for each half hour of the day.

[80] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 Jan 2018.

[81] ASX energy futures are exchange-traded energy financial derivatives, which allow retailers to reduce the spot price volatility risk when purchasing electricity from the NEM. For more information, see https://www.asxenergy.com.au/.

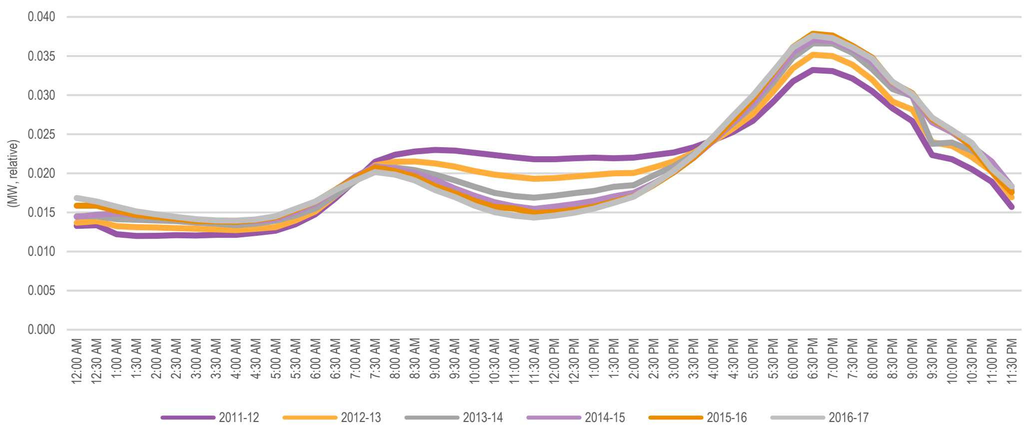
ACIL Allen estimated that wholesale energy costs in 2018–19 will:

- decrease by 1.8 per cent to $101.22 per MWh for the Energex NSLP
- decrease by 3.4 per cent to $89.64 per MWh for the Ergon NSLP
- increase by 8.3 per cent to $61.46 per MWh for the Energex CLP 9000 (retail tariff 31)
- increase by 5.0 per cent to $79.17 per MWh for the Energex CLP 9100 (retail tariff 33).

4.1.1 Demand profiles and historic energy cost levels

Over the past few years, the Energex and Ergon NSLPs have become 'peakier', due to increased penetration of rooftop solar photovoltaic, reducing daytime demand but having limited effect on the evening peak demand (see Figures 6 and 7). On the Energex NSLP, more electricity from the grid is consumed during peak periods than on other demand profiles. Consequently, the Energex NSLP has the highest wholesale energy costs of the profiles analysed in Queensland. The Ergon NSLP is less peaky than the Energex NSLP and, consequently, has lower wholesale energy costs.

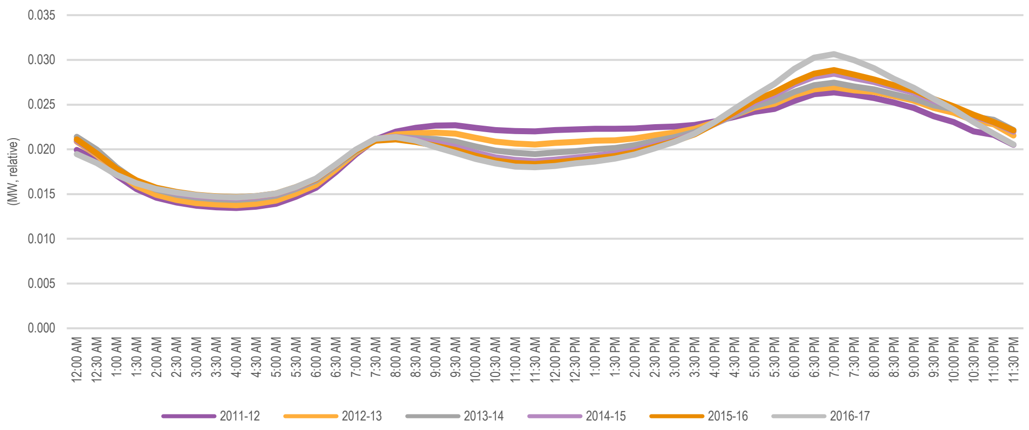
Figure 6 Energex NSLP



Note: The term 'relative MW' means the annual loads for each profile have been scaled so they sum to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 11.

Figure 7 Ergon NSLP

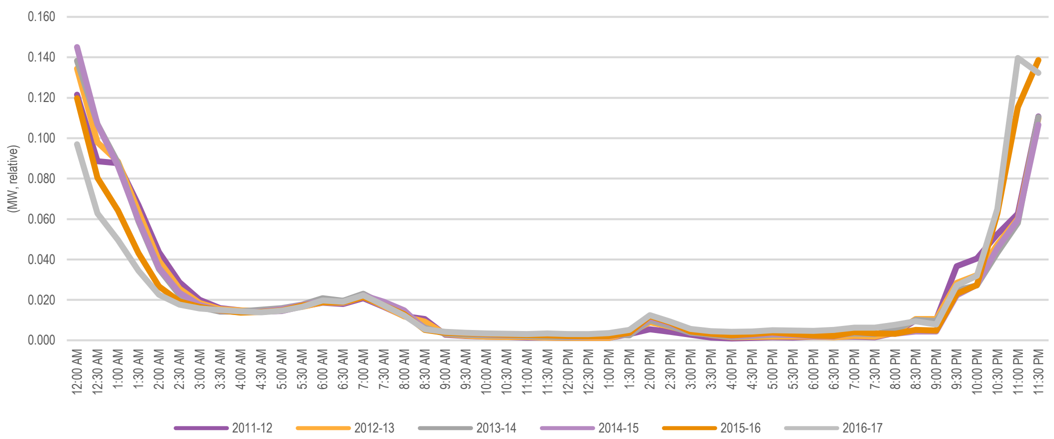


Note: The term 'relative MW' means the annual loads for each profile have been scaled so they sum to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 11.

On the Energex CLPs, more electricity is generally consumed during off-peak periods and non-summer quarters (due to higher water heating loads in non-summer months) than on the Energex and Ergon NSLPs. Therefore, the Energex CLPs have lower wholesale energy costs relative to the NSLPs. The Energex CLP for retail tariff 33 typically has a higher wholesale energy cost than the Energex CLP for retail tariff 31. This is because the former generally has more electricity consumed during daylight hours and the evening peak than the latter. Figures 8 and 9 show the Energex CLPs.

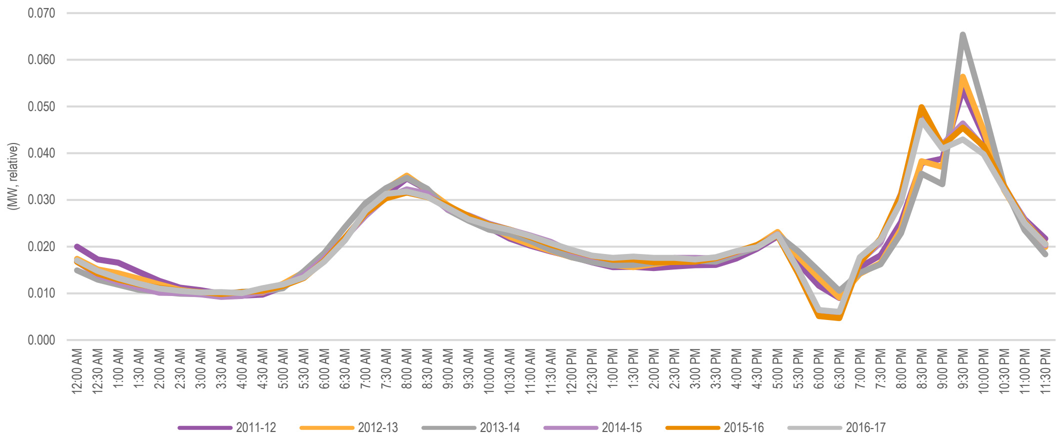
Figure 8 Energex CLP for retail tariff 31



Note: The term 'relative MW' means the annual loads for each profile have been scaled so they sum to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 11.

Figure 9 Energex CLP for retail tariff 33



Note: The term 'relative MW' means the annual loads for each profile have been scaled so they sum to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 11.

ACIL Allen advised that its wholesale energy market modelling aligns with the market's expectations of spot price outcomes for 2018–19. ASX futures contract prices for 2018–19 (on a trade-weighted basis) have increased for base contracts but declined for peak and cap contracts, compared to prices estimated for the 2017–18 price determination (see section 4.1.2). Generally, the purchase of ASX futures enables retailers to lock in a price, or a maximum price (in the case of caps), at which electricity will be exchanged at a future date. Therefore, futures contract prices incorporate market participants' expectations of future spot prices.

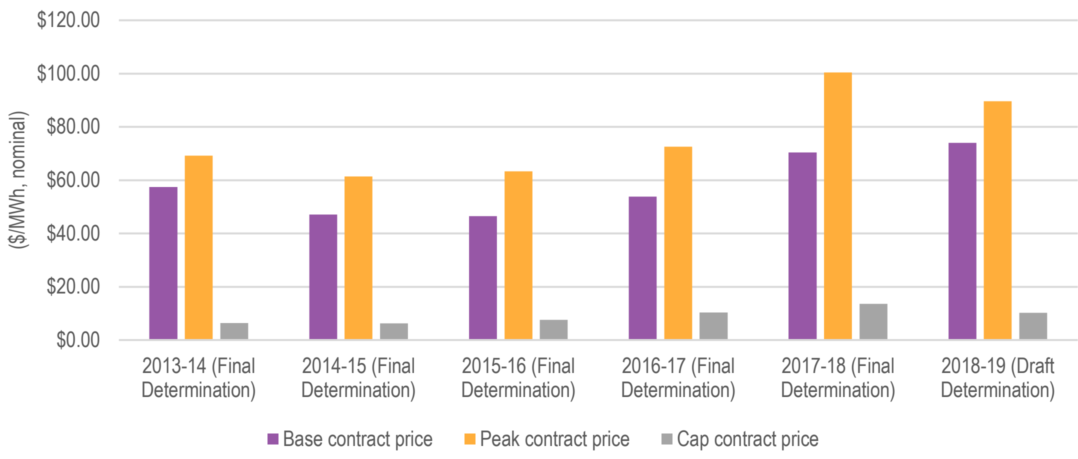
4.1.2 Estimating contract prices

Contract prices for financial derivatives were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for 2018–19. To calculate the trade-weighted futures contract prices, ACIL Allen has used the contract prices and volume of contracts traded up until 10 January 2018.

Compared to the contract prices estimated for the 2017–18 price determination, futures contract prices for 2018–19, on an annualised and trade-weighted basis, have:

- increased by about $3.50 per MWh for base contracts
- decreased by about $11.00 per MWh for peak contracts
- decreased by about $3.50 per MWh for cap contracts.

Figure 10 Annualised quarterly electricity futures contract prices ($/MWh), 2018–19 draft determination and previous final determinations



Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 13.

ACIL Allen advised that this is a reflection of market participants expecting some softening in spot price outcomes and lower price volatility, due to:

- the large amount of renewable generation expected to enter service in 2018–19 (approximately 5000 MW of utility-scale solar and wind generation into the NEM, with 1800 MW committed to enter the Queensland market)
- the Queensland Government's directive to Stanwell in June 2017, instructing Stanwell to adjust its bidding behaviour to put downward pressure on spot prices
- the potential change in the operation of the Wivenhoe pump storage facility due to the expected establishment of CleanCo.[82]

However, recent base contract prices have not fallen to the same extent as peak and cap contract prices and, on a trade-weighted basis, base contract prices are higher than those estimated for 2017–18. ACIL Allen advised that prolonged coal supply issues for some coal-fired generators in New South Wales and continuing strong gas prices have influenced the market's expectations and have therefore acted as a lower bound on base contract prices for 2018–19 to date.

Data extension

In the ICP, we proposed to extend the energy data cut-off date to the end of January for this draft determination, subject to the practicalities of doing so. Extending the data cut-off date would allow us to account for some of the developments within the NEM and energy financial markets that occurred over the summer period. This in turn could potentially reduce the variation in the wholesale energy cost estimates between the draft and final determinations.

In their submissions to the QCA, Canegrowers[83], the Queensland Consumers' Association[84] and Energy Queensland[85] supported extending the energy data cut-off date to the end of January.

[82] The Queensland Government is currently investigating a restructure of government-owned generators and the establishment of a separate entity—CleanCo—to operate the government's existing renewable energy generation assets and develop new renewable energy projects.

[83] Canegrowers, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 19 Jan 2018.

To account for the developments within wholesale energy related markets over the summer period to the greatest extent possible—while publishing the draft determination in February 2018—we extended the data cut-off date to 10 January 2018. The data cut-off date for the previous draft determination was mid-November 2016, but ACIL Allen has now included an additional two months of data for contract prices and volume of contracts traded in its energy cost analysis for the 2018–19 draft determination.

4.1.3 Impact of CleanCo on wholesale energy costs

The covering letter to the delegation specifies that the QCA should consider the impact of the establishment of CleanCo, where relevant, when determining notified prices for 2018–19. The Queensland Government is currently investigating a restructure of government-owned generators and the formation of a separate entity—CleanCo, to operate the government's existing renewable energy generation assets and develop new renewable energy projects.

It is expected that CleanCo would operate the Wivenhoe pumped storage hydroelectric plant. ACIL Allen advised that the key impact of CleanCo for 2018–19 would be the potential change in the operation of Wivenhoe. Historically, on an annual basis, Wivenhoe has operated only about one per cent of its generation capacity of 500 MW.

However, as part of a smaller generation portfolio, if Wivenhoe was to be operated more aggressively and ramped up during periods of high spot prices, then it would likely place downward pressure on peak price outcomes. Alternatively, Wivenhoe could be operated to complement the intermittent supply of other renewable generation, such as wind and solar, in which case the spot price impact would be less prominent. At this stage, it is unclear as to whether the Queensland Government or CleanCo envisages a change in role for Wivenhoe as part of a smaller generation portfolio.

Consequently, ACIL Allen has not included the potential impact of CleanCo as part of its energy market modelling for the draft determination. ACIL Allen advised that if there is more transparency on the role of Wivenhoe under CleanCo over the coming months, then it will adopt the necessary changes in the market modelling and incorporate the impact of CleanCo in its wholesale energy cost estimates for the final determination.

Consistent with the cover letter to the delegation, we have considered the potential impact of the establishment of CleanCo and we accept ACIL Allen's recommendation that, at this time, it is not possible to quantify any potential impacts for the draft determination.

4.1.4 Comparison with the AEMC price trend report

In December 2017, the AEMC, with the assistance of Frontier Economics (Frontier), released a report on residential electricity price trends.[86] In this report, it is suggested that between 2017–18 and 2018–19 wholesale energy costs will decrease by 15.7 per cent for a typical household in south east Queensland. This decrease is noticeably larger than the decreases estimated by ACIL Allen, which used a market hedging approach.

ACIL Allen advised that Frontier's approach appears to estimate contract prices by applying a 5.0 per cent premium to the modelled spot prices for 2018–19, and then using an undefined

[84] Queensland Consumers Association, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 15 Jan 2018.
[85] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 Jan 2018.
[86] AEMC, *2017 Residential Electricity Price Trends*, final report, December 2017.

hedging strategy to estimate wholesale energy costs. In other words, this approach does not appear to consider a prudent hedging strategy in which retailers build up a portfolio of financial derivatives over a period of time ahead of 2018–19.

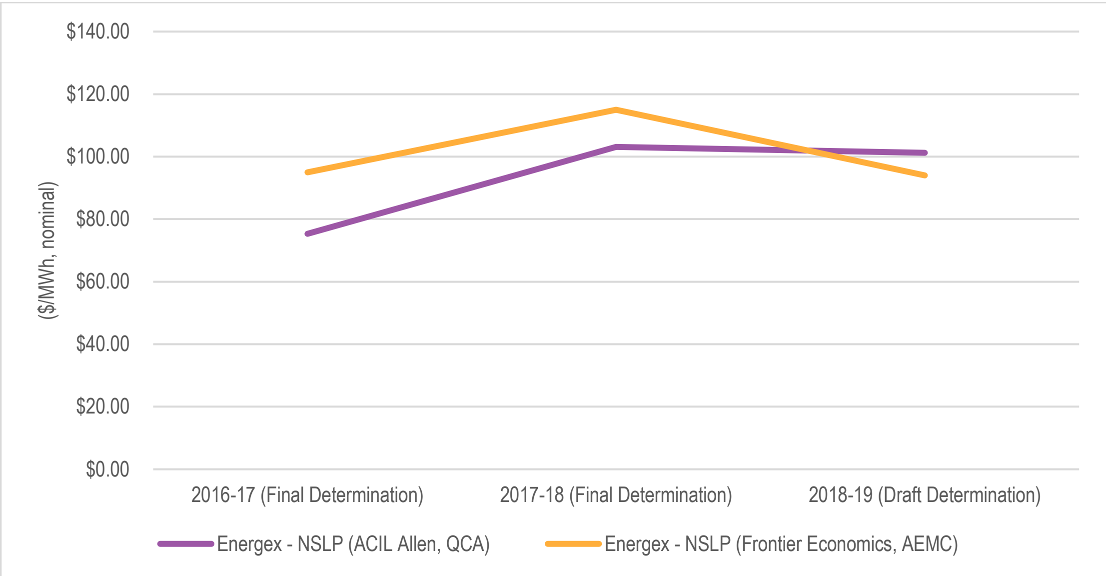
To manage spot price volatility risk, retailers generally purchase futures contracts in advance—to lock in the price (i.e. contract price) for an amount of electricity that they have to pay for in the future. Contract prices fluctuate due to the actual and anticipated changes in the supply–demand balance within the NEM and futures markets, at a particular point in time.

Past contract prices—reflecting the market's expectations of future spot prices at an earlier time—may have a significant impact on the wholesale energy costs incurred by retailers over a period of time, if the market's expectations change noticeably over time. This is because retailers would have locked in their future electricity prices in advance based on the contract prices of that time. To account for this effect, ACIL Allen has:

- simulated a retailer that hedges spot price risk by purchasing financial derivatives in advance, through building up a portfolio of contracts to minimise any volatility in contract prices
- estimated contract prices using a trade-weighted approach, considering the contract prices and volume of contracts traded up until 10 January 2018.

As ACIL Allen noted in its 2018–19 draft report, while it may be appealing to adopt Frontier's methodology and derive lower wholesale energy cost estimates for this pricing year, there is a risk that such an approach may result in higher cost estimates in other years. This can be demonstrated by comparing the estimated wholesale energy costs of ACIL Allen's and Frontier's approaches between 2016–17 and 2018–19 (Figure 11).

Figure 11 Wholesale energy costs ($/MWh) for the Energex NSLP—ACIL Allen and Frontier estimates, 2016–17 to 2018–19



Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 26.

The differences between ACIL Allen's and Frontier's estimates generally can be attributed to the effect of retailers hedging their spot price risk in advance. For the 2016–17 and 2017–18 price determinations, despite a substantial increase in contract prices during the summer of 2015 and 2016, ACIL Allen estimated lower wholesale energy costs than Frontier's approach. This is because, under ACIL Allen's approach, retailers locked in their future electricity prices for a proportion of electricity to be demanded in 2016–17 and 2017–18 before the spike in contract prices during the summers of 2015 and 2016.

Conversely, for the 2018–19 draft determination, despite a recent decline in contract prices, ACIL Allen's estimated wholesale energy costs are higher than Frontier's. This is due to ACIL Allen's approach accounting for the fact that retailers had already locked in higher future electricity prices for a proportion of electricity to be demanded in 2018–19, before the recent decline in contract prices.

In practice, it is highly unlikely that retailers would not pursue some form of hedging strategy to manage their spot price risk in advance. Therefore, to produce robust cost estimates that reflect the actual costs retailers incur when purchasing electricity from the NEM, it is necessary to account for the effects of advanced (or before-the-event) hedging on wholesale energy costs.

4.1.5 QCA position

The QCA considers that ACIL Allen's market hedging approach:

- adequately takes into account the issues raised in submissions
- is transparent and likely to produce reliable estimates that best reflect the actual costs retailers incur when purchasing electricity from the NEM.

The QCA notes that maintaining an approach for 2018–19 that is consistent with the approach adopted in previous determinations will also provide certainty to stakeholders.

The QCA's draft decision is to accept ACIL Allen's advice on this matter and its draft wholesale cost estimates, which are outlined in the table below. We expect ACIL Allen will update these estimates for the final determination, based on the latest available data.

To be consistent with the UTP, we propose to use the wholesale energy cost estimates of the Energex NSLP and CLPs for residential, small business and unmetered supply (excluding street lighting) customers.

Table 9 Estimated wholesale energy costs at the Queensland regional reference node, 2018–19

Settlement class	*Retail tariff*	*Wholesale energy cost*	*Change from 2017–18*	
		$/MWh	*%*	*$/MWh*
Energex NSLP and unmetered supply	11, 12A, 14, 15, 20, 22A, 24, 41, 91	$101.22	–1.8	–$1.89
Energex CLP 9000	31	$61.46	8.3	$4.70
Energex CLP 9100	33	$79.17	5.0	$3.79
Ergon Energy NSLP—SAC demand and street lighting	44, 45, 46, 50, 71	$89.64	–3.4	–$3.11
Ergon Energy NSLP—high voltage—CAC and ICC	51A, 51B, 51C, 51D, 52A, 52B, 52C, 53	$89.64	–3.4	–$3.11

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 24.

4.2 Other energy costs

In addition to wholesale energy costs, the QCA must account for other energy costs that retailers incur when purchasing electricity from the NEM:

- Renewable Energy Target (RET) costs
- NEM management fees[87] and ancillary services charges
- prudential capital costs.

4.2.1 Renewable Energy Target costs

The RET scheme, comprised of the Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES), provides incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions. The costs of these incentives are paid by retailers through the purchase of Large-scale Generation Certificates (LGCs) and Small-scale Technology Certificates (STCs). Retailers surrender the purchased LGCs and STCs to the Clean Energy Regulator (CER) to meet their obligations under the RET scheme.

LRET costs

The LRET sets annual targets for the amount of electricity that must be sourced from large-scale renewable energy projects such as utility-scale wind and solar generation. The mandated LRETs for 2018 and 2019 are 28,637 GWh and 31,244 GWh respectively.[88]

Retailers must purchase a set number of LGCs according to the:

- renewable power percentage (RPP) published by the CER
- amount of electricity they have sold to customers in the calendar year.

For its advice on the 2017–18 price determination, ACIL Allen estimated LRET costs using a market-based approach. Under this approach, LRET costs for the relevant calendar years were estimated by multiplying the expected average LGC prices and RPP values. The LRET cost for the financial year was derived by averaging the two calendar year estimates.

The expected average LGC prices were estimated using LGC forward prices published by the Australian Financial Markets Association (AFMA) and provided by TFS.[89] The implied RPP value was estimated by dividing the LRET target and implied total electricity consumed (projected by the CER). To calculate the implied total electricity consumption, ACIL Allen used the SRES data published by the CER, which include the projected STCs required and non-binding small-scale technology percentage (STP). The implied electricity consumed is estimated by dividing the projected STCs by the relevant non-binding STP.

In its submission on the ICP, Energy Queensland supported the use of TFS data to estimate LRET costs.

[87] The NEM management fees were formerly referred to as the NEM participation fees.
[88] Section 40, *Renewable Energy (Electricity) Act 2000* (Cth).
[89] ACIL Allen used AFMA data up until September 2016. However, due to AFMA ceasing publication of this data at the end of September 2016, ACIL Allen has used TFS broker data from October 2016 through to January 2018. ACIL Allen examined the LGC forward prices—prior to September 2016—that TFS provided, and was satisfied they were consistent with AFMA data. Therefore, it concluded that the TFS data is suitable for the purpose of estimating LRET costs.

Canegrowers noted:

> The methodology relied on by QCA appears to assume Ergon retail is a marginal retailer with no long-term offtake contracts in place and no investments in renewable energy capacity. In the context of the Queensland government's policy push towards renewables it is likely that an efficient prudent retailer, such as Ergon Retail, with evergreen customer contracts would actively manage this exposure by being long on investment with respect to renewables.[90]

In the absence of confidential data showing the actual LGC contractual position of Ergon Energy or other retailers in south east Queensland, ACIL Allen is maintaining the view that transparent market prices provide a better indicator of actual LGC costs compared to any modelled estimates. A more detailed response by ACIL Allen is in chapter 3 of its 2018–19 draft report.

In its 2018–19 draft report, ACIL Allen estimated LRET costs using an approach consistent with the previous determination. ACIL Allen has provided a detailed explanation of its calculations in chapter 4 of its report, along with information on LGC forward prices and the assumptions underpinning the implied RPPs used.

ACIL Allen advised that LGC forward prices have softened slightly since they were last estimated for the 2017–18 final determination. This is primarily due to:

- a number of renewable energy projects reaching financial close in recent months, with most of these projects expected to be commissioned during 2018
- the mix of near-term renewable energy projects having a higher proportion of solar projects than wind, with solar projects having a shorter lead time to commissioning.

However, the slight softening in LGC forward prices was offset by an increase in RPPs as a higher RPP increases the number of LGCs that retailers have to surrender to the CER.

Using the expected average LGC prices and implied RPPs, ACIL Allen estimated that the LRET cost for 2018–19 would be $12.99 per MWh for all retail tariffs, an increase of $1.02 per MWh compared to the 2017–18 final determination.

QCA position

The QCA considers that ACIL Allen's market-based approach, using the most up-to-date targets and price information published by AFMA, TFS and the CER, is likely to produce the most reliable estimate of LRET costs to be incurred by retailers in 2018–19. The QCA notes that maintaining an approach for 2018–19 that is consistent with the approach used in previous determinations will also provide certainty to stakeholders.

The QCA's draft decision is to accept ACIL Allen's advice on this matter and its draft LRET cost estimates (Tables 10 and 11). We expect ACIL Allen will update this cost estimate for the final determination, to incorporate the final RPP for 2018.

SRES costs

The SRES provides an incentive for individuals and small businesses to install eligible small-scale renewable energy systems—such as solar panel systems, small-scale wind systems, small-scale hydro systems, solar hot water systems and heat pumps. Customers installing these systems create STCs, which retailers must purchase and surrender to the CER.

[90] Canegrowers, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 19 Jan 2018.

For its advice on the 2017–18 price determination, ACIL Allen estimated SRES costs by multiplying the expected STC price and the calendar year STP published by the CER. The SRES cost for the financial year was derived by averaging the two calendar year estimates. The expected STC price was based on the clearing house price.[91] The calendar year STPs were based on the final 2017 STP and the latest non-binding 2018 STP published by the CER.

In its 2018–19 draft report, ACIL Allen estimated SRES costs using the same approach as 2017–18. It estimated that the SRES cost for 2018–19 would be $3.12 per MWh for all retail tariffs, an increase of $0.11 per MWh compared to the 2017–18 final determination. This SRES cost estimate is based on the latest non-binding STP for 2018 and 2019 published by the CER.

QCA position

The QCA considers that ACIL Allen's approach is likely to produce the most reliable estimate of SRES costs to be incurred by retailers in 2018–19. The QCA also notes that maintaining a consistent approach for 2018–19 will also provide certainty to stakeholders.

Therefore, the QCA proposes to accept ACIL Allen's advice on this matter and its draft SRES cost estimates, which are outlined in Tables 10 and 11. We expect ACIL Allen will update the estimate in its final report using the final STP for 2018, which is due to be published by the CER on 31 March 2018, and the latest non-binding STP for 2019.

4.2.2 NEM management fees and ancillary services charges

Retailers purchasing electricity from the NEM are required to pay NEM management fees and ancillary services charges to the Australian Energy Market Operator (AEMO). NEM management fees are levied by AEMO to cover the costs related to:

- operating the NEM,
- performing its function as the National Transmission Planner
- full retail contestability
- funding Energy Consumers Australia.

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability.

For its advice on the 2017–18 price determination, ACIL Allen used AEMO's budget and fee projections to estimate the NEM management fees. Ancillary services charges were estimated by using the average ancillary service payments[92] observed over the preceding 52 weeks.

In its 2018–19 draft report, ACIL Allen estimated the NEM management fees and ancillary services charges using the same methodology as in 2017–18. It estimated the NEM management fees using the projected fees in AEMO's *Electricity Final Budget and Fees 2017–18* report.

The ancillary services charge was estimated based on the average costs observed over the preceding 52 weeks. The costs of providing ancillary services have increased since the 2017–18 final determination due to a number of large ancillary service payments made during

[91] The STC clearing house is operated by the CER and the clearing house price is fixed at $40 per STC (or per MWh of electricity generated by eligible systems).

[92] AEMO provides data on weekly settlements, for ancillary service payments in each interconnected region within the NEM.

September and October 2017. More details on ACIL Allen's approach are available in chapter 4 of its 2018–19 draft report.

ACIL Allen estimated that for 2018–19, NEM management fees would be $0.53 per MWh and ancillary services costs would be $0.42 per MWh.

QCA position

The QCA considers that ACIL Allen's approach is likely to produce the most reliable estimate of NEM management and ancillary services costs to be incurred by retailers in 2018–19. The QCA notes that maintaining an approach for 2018–19 that is consistent with the approach in previous years will also provide certainty to stakeholders.

The QCA's draft decision is to accept ACIL Allen's advice on this matter and its draft cost estimates (Tables 10 and 11). We expect that ACIL Allen will update these cost estimates in its final report, based on the latest projected fees and settlements data for ancillary service payments provided by AEMO.

4.2.3 Prudential capital costs

Prudential capital costs are the costs that a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX in order to trade in futures contracts. These costs must be accounted for, as futures contracts are relied upon to derive the wholesale energy costs estimates. For the 2017–18 price determination, ACIL Allen estimated prudential capital costs in line with the latest published AEMO requirements and margin requirements for trading in the ASX futures market.

In its submission on the ICP, Canegrowers proposed that the Ergon NSLP be used to calculate prudential costs. We agree with Canegrowers that using the consumption profile of the Ergon NSLP to calculate prudential costs (for customers on the same profile) will improve the accuracy of the cost estimates. Consequently, we have instructed ACIL Allen to refine its methodology and use:

- the Ergon NSLP to estimate the prudential costs for customers on the Ergon NSLP
- the Energex NSLP to estimate the prudential costs for customers on the Energex NSLP and CLPs.

Note that, to be consistent with the UTP[93], we need to use the energy cost estimates of:

- the Energex NSLP for residential, small business and unmetered supply (excluding street lighting) customers
- the Ergon NSLP for large business and street lighting customers.

In its 2018–19 draft report, ACIL Allen estimated prudential costs using an approach that is largely consistent with its 2017–18 approach. Consistent with previous determinations, prudential costs for customers on the Energex NSLP were estimated using the consumption profile of the Energex NSLP. These costs were also used as a proxy for the prudential costs of customers on the Energex CLPs. However, as previously noted, ACIL Allen has refined its approach in estimating the prudential costs for customers on the Ergon NSLP by using the consumption profile of the Ergon NSLP. More details on ACIL Allen's approach are available in chapter 4 of its 2018–19 draft report.

[93] See Chapters 1 and 2 for further detail.

Prudential costs have risen since the 2017–18 final determination, largely driven by higher hedge prudential costs—including a higher initial margin required by the ASX due to higher expected price volatility. ACIL Allen estimated that prudential costs for the Energex and Ergon NSLP for 2018–19 would be $3.16 per MWh and $2.27 per MWh respectively.

QCA position

The QCA considers that ACIL Allen's approach is likely to produce the most reliable estimate of prudential capital costs to be incurred by retailers in 2018–19. Therefore, the QCA's draft decision is to accept ACIL Allen's advice on this matter and its draft prudential capital cost estimates, which are in Tables 10 and 11.

4.2.4 Summary of other energy costs for 2018–19

Tables 10 and 11 set out the draft estimates of other energy costs for 2018–19, which will form part of the total energy cost allowances for retail tariffs.

Table 10 Other energy costs (excluding losses)—Energex NSLP and CLPs

Cost component	*$/MWh*	*Change from 2017–18*	
		%	*$/MWh*
LRET	$12.99	8.5	$1.02
SRES	$3.12	3.7	$0.11
NEM fees	$0.53	0.0	$0.00
Ancillary services	$0.42	23.5	$0.08
Prudential capital	$3.16	24.9	$0.63
Total	**$20.22**	**10.0%**	**$1.84**

Note: Totals may not add due to rounding.

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, pp. 29, 33.

Table 11 Other energy costs (excluding losses)—Ergon NSLP

Cost component	*$/MWh*	*Change from 2017–18*	
		%	*$/MWh*
LRET	$12.99	8.5	$1.02
SRES	$3.12	3.7	$0.11
NEM fees	$0.53	0.0	$0.00
Ancillary services	$0.42	23.5	$0.08
Prudential capital	$2.27	-	-
Total	**$19.33**	**-**	**-**

Note: Totals may not add due to rounding.

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, pp. 29, 33.

4.3 Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

Consistent with its approach in 2017–18, ACIL Allen has accounted for energy losses by applying transmission and distribution loss factors published by AEMO in a manner that aligns with AEMO's settlement process. These losses are based on AEMO's 2017–18 published loss factors, as loss factors for 2018–19 have not yet been published.

QCA position

The QCA's draft decision is to accept ACIL Allen's advice on this matter and its draft loss factor calculations (Table 12). We expect ACIL Allen will update the loss factors using AEMO's 2018–19 loss factors in its final report.

4.4 Draft total energy cost allowances for 2018–19

Table 12 summarises the QCA's draft decision on energy cost allowances for each retail tariff for 2018–19. To be consistent with the UTP[94], we propose to use the cost estimates of:

- the Energex NSLP and CLPs for residential, small business and unmetered supply (excluding street lighting) customers
- the Ergon NSLP for large business and street lighting customers.

Table 12 Total energy cost allowances for 2018–19, draft decision

Settlement class	*Retail tariff*	*Wholesale energy costs*	*Other energy costs*	*Energy losses*	*Total energy cost allowance*		*Change from 2017–18*
		$/MWh		*%*	*$/MWh*	*c/kWh*	*%*
Energex NSLP and unmetered supply	11, 12A, 14, 15, 20, 22A,24, 41, 91	$101.22	$20.22	6.5	$129.33	12.933	–0.05
Energex CLP 9000	31	$61.46	$20.22	6.5	$86.99	8.699	8.7
Energex CLP 9100	33	$79.17	$20.22	6.5	$105.85	10.585	6.0
Ergon Energy NSLP—SAC demand and street lighting	44, 45, 46, 50, 71	$89.64	$19.33	7.9	$117.58	11.758	–1.9
Ergon Energy NSLP, high voltage—CAC and ICC	51A, 51B, 51C, 51D, 52A, 52B, 52C, 53	$89.64	$19.33	1.4	$110.50	11.050	–1.9

Note: Totals may not add due to rounding.

Source: ACIL Allen, Estimated Energy Costs for 2018–19, February 2018, p. 34.

[94] See Chapters 1 and 2 for further detail.

5 RETAIL COSTS

The second element of the R component is retail costs, which include retail operating costs, a retail margin, and metering costs.

The QCA proposes to:

- *maintain retail cost allowances for residential and small business customers in real terms—by adjusting fixed retail cost allowances by forecast CPI, and maintaining variable retail cost percentage allocators at 11.27 per cent for residential customers and 12.8 per cent for small business customers*
- *maintain retail cost allowances for large and very large business customers—by adjusting fixed retail cost allowances by forecast CPI, and maintaining variable retail cost allocators at 6.0445 per cent*
- *base residential and small business customer metering charges for accumulation (type 5 and 6) meters on draft metering charges provided by distributors*
- *base advanced digital (type 1–4) meter charges on averages of retailer information provided under section 90A of the Act.*

5.1 Retail cost allowances

The retail cost allowance includes retail operating costs (ROC) and a retail margin. ROC are the costs associated with services provided by a retailer to its customers, and typically include customer administration, call centres, corporate overheads, billing and revenue collection, IT systems, regulatory compliance, and customer acquisition and retention costs (CARC). The retail margin represents the return to investors for retailers' exposure to systematic risks associated with providing retail electricity services. The margin can also include other costs incurred by retailers—such as depreciation, amortisation, interest payments and tax expenses.

For our 2017–18 price determination, we maintained the fixed retail cost allowances established in our 2016–17 final price determination in real terms, and maintained variable retail cost percentage allocators as the same proportion of other variable costs established in the 2016–17 final price determination.[95] The 2017–18 decision was in line with our 2016–17 determination, which noted that the thorough review of retail costs conducted for the 2016–17 determination should produce robust estimates that could then be updated annually, using a defined escalation method.

Submissions

Canegrowers considered that the QCA's retail cost estimates were excessive as they included competition costs which, it argued, were not incurred by Ergon Retail. Canegrowers also considered that the retail allowances incorporated 'excess margins' and did not reflect efficient retailer costs.

Canegrowers Isis considered that retail cost allowances should be fixed for a period of up to five years, to encourage greater retailer efficiency. The Queensland Consumers' Association considered that retail costs should not be increased by the change in CPI unless there is

[95] More information on retail cost allowances can be found in our 2016–17 final price determination and ACIL Allen's associated reports, which are available on our website.

evidence that costs have increased by this amount, and noted that retailers were seeking to reduce costs by encouraging electronic billing, payment, and contact methods.

Origin Energy considered that the level of competition for new customers in south east Queensland had led to upward pressure on the cost to service customers. Energy Queensland considered that the national 'Power of Choice' project had impacted costs for all participants in the National Electricity Market (NEM), but it supported the approach taken by the QCA in 2017–18 and considered it reasonable to again index retail cost allowances by CPI.

QCA position

The QCA proposes to maintain existing fixed retail cost allowances in real terms, and maintain variable retail cost percentage allocators as the same proportion of other variable costs established in the 2016–17 and 2017–18 final price determinations.

We consider the retail cost allowances established in 2017–18 are an appropriate starting point for establishing the 2018–19 retail cost allowances.

As discussed in Chapter 2, under the UTP, the QCA must consider setting notified prices for residential and small business customers based on standing offer prices in south east Queensland. In order to do this, the QCA must estimate the overall level of retail costs (including competition costs and retail margin) charged in the south east Queensland market in 2018–19. While it is highly unlikely that Ergon Retail will incur the same level of CARC for residential and small business customers as a retailer in south east Queensland, the actual competition costs incurred by Ergon Retail are irrelevant to setting prices that reflect the government's chosen UTP benchmark. Removing competition costs from retail costs would result in notified prices that are inconsistent with the UTP.

We note comments from consumer groups who considered that retail allowances should be frozen, effectively reducing them in real terms. While electronic billing, payment and communication may reduce retailer costs, these practices have been widespread for many years. As such, efficiencies from electronic billing, payment and contact systems will already be present in the retail cost benchmarks established in 2016–17. For the QCA to freeze retail cost allowances, it would need material evidence that ROC borne by residential and small business customers in south east Queensland, and large customers in regional Queensland, were likely to fall in real terms in 2018–19.

Maintaining retail cost allowances in real terms is consistent with our previous approaches to setting retail prices, as well as with the UTP.

For residential and small business customers, we propose to maintain retail cost allowances in real terms by:

- adjusting the fixed retail cost allowances (that were estimated for 2017–18) by the Reserve Bank of Australia's forecast of the change in the CPI for 2018–19[96]—to maintain them in real terms
- maintaining the variable retail cost percentage allocators at 11.27 per cent for residential customers and 12.8 per cent for small business customers—the same proportions of other variable costs first established in the 2016–17 final price determination.

[96] We adopted a CPI of 2.125 per cent, equal to the average of forecast inflation at 30 June 2018 and 30 June 2019. See Reserve Bank of Australia, Statement on Monetary Policy, November 2017, table 6.1, p. 67.

Consistent with the 2017–18 price determination, we propose to adjust fixed retail cost allowances for large and very large business customers by forecast CPI[97], and maintain variable retail cost allocators at 6.0445 per cent.

5.2 Metering costs

5.2.1 Background

In previous determinations, the QCA was unable to consider metering charges as part of notified prices, as regulated metering charges Ergon Distribution charged to Ergon Retail were distribution non-network charges.[98] For this reason, 2017–18 retail cost allowances excluded metering costs. However, the Australian Energy Market Commission (AEMC) has introduced a rule change to promote greater competition in metering, and facilitate a market-led deployment of advanced meters.[99] This rule change is part of the 'Power of Choice' reforms initiated by the COAG Energy Council.

Under these reforms, all new and replacement meters must be advanced digital meters. Retailers must appoint a metering coordinator who arranges for meter installation, maintenance and reading on behalf of the retailer.[100] The new market structure is shown in the AEMC infographic (Figure 12) below. The change means that metering charges imposed by a metering coordinator[101] are not distribution non-network charges and, as a result, should be considered in setting notified prices. [102]

[97] We adopted a CPI of 2.125 per cent, equal to the average of forecast inflation at 30 June 2018 and 30 June 2019. See Reserve Bank of Australia, Statement on Monetary Policy, November 2017, table 6.1, p. 67.

[98] Section 90(3) of the Electricity Act states that a price determination cannot be made for distribution non-network charges.

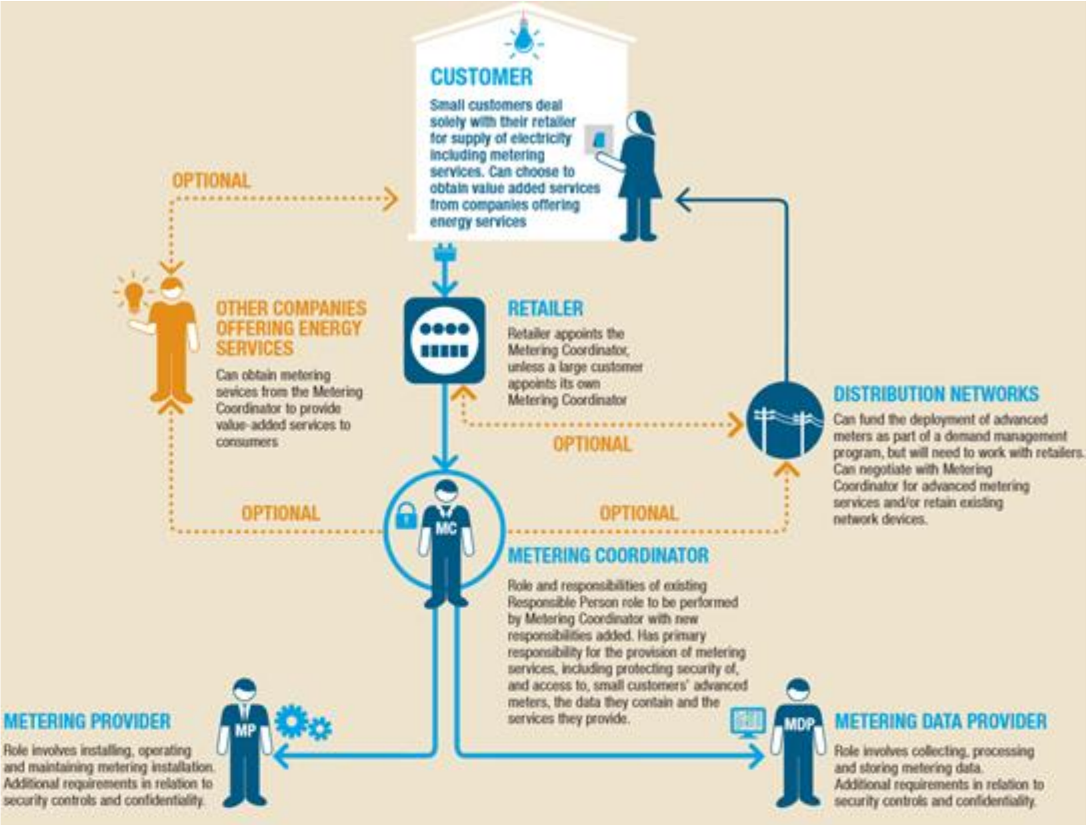
[99] See http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv for more information.

[100] For existing accumulation meters, distributors will be the default metering coordinator. However, retailers may appoint a different metering coordinator party to perform these metering services in future. Large customers or non-market and exempt generators are permitted to appoint their own metering coordinator.

[101] We understand that, at the time of making our draft determination, Energy Queensland is still in the process of adapting its operations to the new structure required by the AEMC rule change. Ergon Distribution continues to charge retailers metering charges for type 6 meters. As a result, these remain distribution non-network charges until Energy Queensland adopts the new structure. The AER has granted Energy Queensland a temporary waiver from these requirements to allow it more time to adapt its operations. This waiver expires on 1 July 2018, the day that our notified prices will apply from.

[102] Regulated metering charges paid to Ergon Distribution by a retailer remain distribution non-network charges. See section 5.2.2 for further information.

Figure 12 Power of Choice metering arrangements



Source: AEMC.[103]

Stakeholders should note that, at the time of making this draft determination, we understand this new structure has not been fully implemented by Ergon Distribution. In the interim, some metering charges will remain distribution non-network charges. This is discussed further in section 5.2.2.

5.2.2 Meter types

There are two predominant types of electricity meters—accumulation meters[104] and advanced digital meters (often referred to as 'smart meters').[105]

Accumulation meters

At present, electricity usage of most residential and small business customers in Queensland is measured using an accumulation meter. These meters record accumulated electricity usage over time, and must be read manually. Early accumulation meters were mechanical meters with a 'spinning disc' and clockwork dials to record electricity consumption. Modern accumulation meters have a digital display.

Residential and small business customers with accumulation meters currently pay regulated charges for metering. Two charges are paid—one to recover the capital cost of the meter, and

[103] AEMC, http://www.aemc.gov.au/getattachment/87a49036-707f-446b-92fb-b333543da21b/Information-sheet-—-overview.aspx.
[104] Type 5 and 6 meters.
[105] Type 1–4 meters.

another to recover non-capital costs for operation and maintenance. Retailers may present these on customer bills separately, or bundled with the service fee.

Customers in regional Queensland with accumulation meters are currently charged metering service charges based on Energex rates, as the Queensland Government made a policy decision to set these in accordance with the UTP. This is to ensure that customers in regional Queensland pay the same metering services charges as customers in south east Queensland.[106]

As discussed in the previous section, Ergon Distribution is still in the process of implementing the AEMC's rule change. In the interim, retailers operating on the Ergon Distribution network pay metering service charges for accumulation meters to Ergon Distribution directly. As Ergon Distribution’s metering service charges are regulated by the AER, they technically remain distribution non-network charges and will remain outside of notified prices. Any prices set by the QCA for accumulation meter charges will apply once Ergon Distribution is fully compliant with the new rules. We understand this should occur by 1 July 2018.[107]

Advanced digital meters

The electricity usage of most large business customers, and in some cases their demand, is measured through an advanced digital meter, which records data in 30 minute intervals. These meters, frequently referred to as 'interval' or 'smart' meters, are usually read remotely.[108] Under the 'Power of Choice' reforms, meters that have similar functionality will be provided to residential and small business customers when they need a new meter, or where the customer requests one to be installed.

Currently Ergon Retail charges large business customers an upfront meter charge of between $333.61 and $653.97[109] (excluding GST), and $1.97 to $9.54 per day[110] (excluding GST) for ongoing metering costs.

These meters, and associated services, are now offered by multiple organisations in a competitive market. Retailers are able to appoint the metering coordinator(s) of their choice, and large customers are able to appoint their own metering coordinator. Prices for these meters, and associated services, are not regulated.

Submissions

QCOSS supported including advanced digital metering costs, based on costs incurred by south east Queensland retailers, in notified prices. QCOSS stated that alternative payment arrangements, such as the recovery of the metering costs over the economic life of the meter rather than by upfront charges, should be considered. Origin Energy supported separating metering costs from regulated tariffs. Energy Queensland supported including advanced digital metering costs based on the charges applied for accumulation meters, with an appropriate escalation factor applied.

[106] https://www.ergon.com.au/retail/residential/tariffs-and-prices/what-is-the-metering-services-charge

[107] The AER has granted Energy Queensland a temporary waiver from these requirements to allow it more time to adapt its operations. This waiver expires on 1 July 2018.

[108] Where communication infrastructure, such as a mobile phone network, is not available, advanced digital meters will be read manually.

[109] https://www.ergon.com.au/retail/business/tariffs-and-prices/upfront-meter-charges .

[110] https://www.ergon.com.au/retail/business/tariffs-and-prices/meter-services-charges .

QCA position

Accumulation metering costs

The QCA proposes to estimate metering costs for accumulation meters based on the metering charges approved by the AER for the Energex distribution area. This will be consistent with the UTP decision made by the Queensland Government; it will also be consistent with how metering fees are established for residential and small business customers with accumulation meters.

For the draft determination, we have obtained draft 2018–19 metering service charges from Energex. For the final determination, we propose to use metering charges from Energex's final price proposal to the AER. We understand that retailers treat metering charges as a pass-through to customers. Accordingly, the QCA has not applied a retail margin to metering costs.

The QCA agrees with Origin Energy that, in the interests of transparency, metering charges should be presented as separate components of notified prices.

Table 13 shows draft 2018–19 metering charges for residential and small business customers with accumulation meters.

Table 13 Draft residential and small business metering charges for accumulation meters (type 5 and 6) (excluding GST)

Description	***Charge type***	***Rate***	***Unit***
Primary tariff meter charge (per tariff) Tariffs 11, 12A, 20, 22A, 22 (small and large), 37, 62, 65, 66	Capital	7.167	c/day
	Non-capital	2.314	c/day
	Total	9.481	c/day
Controlled load meter charge (per tariff) Tariffs 31, 33	Capital	2.150	c/day
	Non-capital	0.694	c/day
	Total	2.844	c/day

Note: These charges do not apply where Ergon Distribution is acting as the deemed metering coordinator. Ergon Distribution's accumulation metering charges (for type 5 and 6 meters) are regulated by the AER.

Advanced digital metering costs for residential and small business customers

The QCA agrees with QCOSS that, given the Government's current position regarding metering charges and the UTP, the best way to estimate advanced digital metering costs is to base them on the costs incurred by retailers in south east Queensland.

We have considered Energy Queensland's suggestion that advanced digital metering costs be based on the significantly lower costs of accumulation meters for the first two years before moving to full cost recovery from 2020–21. However, the QCA is very concerned that this could lead to customers choosing to install an advanced digital meter without full knowledge of the true costs they will face for doing so in future years.

While basing advanced digital metering costs on south east Queensland price levels would still likely result in prices below the full cost of supply in regional Queensland, it would be consistent with the Queensland Government's UTP.

At the time of writing, retailers do not list additional charges for advanced digital meters for residential and small business customers in south east Queensland.[111] As the metering reforms

[111] Based on information on the Australian Energy Regulator's Energy made Easy website.

have only been in force for a matter of weeks, and there are a relatively small number of residential and small business customers with these meters, retailers may be choosing to absorb the costs in the short term while they develop their systems and pricing strategies. Due to this uncertainty, the QCA considers that estimates based on the costs faced by south east Queensland retailers, rather than the advanced digital metering charges (or lack thereof) that are now being passed through to south east Queensland customers, are likely to be the best available estimates of metering charges at this time.

In order to assess the costs and benefits associated with advanced digital meters, the QCA obtained data from retailers through a formal request for information under section 90A of the Electricity Act. The QCA requested data for flat, time of use, time of use demand and controlled load tariffs for both residential and small business customers in three categories:

(1) the costs, both capital and operational, currently associated with advanced digital meters and the forecast of these costs for 2018–19

(2) the total value of cost savings and efficiency gains from advanced digital meters and the forecast of this value for 2018–19

(3) the charges currently being passed through to customers, and the forecast of these charges for 2018–19.

The request for information was sent to all retailers registered to operate on Queensland distribution networks. While only retailers currently serving customers (residential, small business or large business customers) on notified prices in regional Queensland were legally obliged to provide information in response to the request for information, other retailers chose to provide information voluntarily. The QCA received data from 11 retailers.

The QCA considers this data to be the best dataset obtainable at this time under the current legal framework, and proposes to estimate metering costs based on this data. The data provided was independently reviewed by ACIL Allen. ACIL Allen found that charges reported by one retailer for type 4 meters were above those ACIL Allen considered reasonable. The residential and small customer metering data reported by this retailer was excluded from the QCA's estimates.

While the actual data obtained by the QCA is confidential, in general, metering coordinators were charging retailers flat amounts accounting for capital and operational costs for advanced digital meters, and the charges were generally the same for residential and small business customers. Retailers were generally still in the process of assessing the benefits to their business of advanced digital meters, and were unable to provide information on the value of cost savings and efficiency gains from advanced digital meters.

All the retailers who responded provided information on their 2017–18 advanced digital metering costs, but few were able to provide information on their likely costs for 2018–19 at this time. Some retailers reported that they expected metering costs would increase in line with inflation for 2018–19. For this reason, the QCA proposes to estimate residential and small business metering costs based on the average of all retailer data. Where retailers have provided data for 2017–18 only, we have adjusted this data by forecast CPI to maintain these costs in real terms for 2018–19 and ensure a like-for-like comparison.

Advanced digital meters which do not have the communication function enabled[112], either by customer choice or due to lack of communication infrastructure, must be manually read.

[112] Type 4A meters.

Manual meter reading charges vary according to customer location, with the most expensive areas costing several hundred dollars annually for manual meter reading. The QCA has based charges for advanced digital meters without communication (type 4A) on average manual meter reading costs provided by retailers for their customer bases.

Table 14 shows draft 2018–19 metering charges for residential and small business customers with advanced digital meters. We understand that retailers treat metering charges as a pass-through to customers. Accordingly, the QCA has not applied a retail margin to metering costs.

The QCA agrees with Origin Energy that, in the interests of transparency, metering charges should be presented as separate components of notified prices.

Table 14 Draft residential and small business metering charges for advanced digital meters (type 4 and 4A) (excluding GST)

Description	*Meter type*	*Daily charge (c)*	*Annual cost ($)*
Primary flat rate tariff meter charge (Tariffs 11 and 20—per tariff)	Type 4 (communications enabled) meter	27.590	100.77
	Type 4A (manually read) meter	43.612	159.29
Primary time-of-use tariff meter charge (Tariffs 12A, 22A, 22 (small and large), 37, 62, 65, 66—per tariff)	Type 4 (communications enabled) meter	27.590	100.77
	Type 4A (manually read) meter	43.612	159.29
Primary demand tariff meter charge (Tariffs 14, 15, 24—per tariff)	Type 4 (communications enabled) meter	27.590	100.77
	Type 4A (manually read) meter	43.612	159.29
Primary tariff[a] with controlled load[b] meter charge—per tariff.	Type 4 (communications enabled) meter	30.749	112.31
	Type 4A (manually read) meter	46.771	170.83

a Tariffs 11, 12A, 14, 15, 20, 22A, 22 (small and large), 24, 37, 62, 65, 66

b Tariffs 31 and 33

Note: Customers who request that a working accumulation meter be replaced with an advanced digital meter may need to pay a metering services charge for the capital component of the working meter that was removed. Customers considering a meter replacement should discuss this with their retailer.

Advanced digital metering costs for large business customers

The QCA proposes to estimate advanced digital metering costs for large business customers based on information from retailers obtained via a formal request for information sent to retailers under section 90A of the Electricity Act.

There are some important differences in estimating large business customer advanced digital metering costs compared to residential and small business costs. As with residential and small business customers, there will be costs and benefits that accrue to retailers from advanced digital meters—beyond the costs of the meters and their associated services. Unlike residential and small business customers, large customers have been using advanced digital meters for a number of years, and as a mature market, we would expect their costs and benefits to be well-established. Large business customers are also less homogeneous than residential and small business customers, and in many cases their meters will be specifically tailored to their requirements.

As with residential and small business customers, little public information is available on large business customer metering charges, because this information is generally commercial-in-confidence. The QCA requested data from retailers in three categories:

(1) the costs, both capital and operational, currently associated with advanced digital meters and the forecast of these costs for 2018–19

(2) the total value of cost savings and efficiency gains from advanced digital meters and the forecast of these for 2018–19

(3) the charges currently being passed through to customers, and the forecast of these charges for 2018–19.

The QCA proposes to estimate advanced digital metering costs for large customers based on this information. This request for information was sent to all retailers registered to operate on Queensland distribution networks. Ergon Retail, the only retailer required to supply large business customers at notified prices, and the only retailer legally obliged to provide information, only provided the QCA with a broad range of potential metering costs for large customers, and argued that it should be allowed to continue with its existing approach of charging large customers on an unregulated basis. However, other retailers chose to provide information voluntarily. The QCA received data from five retailers in total.

The data provided by retailers was independently reviewed by ACIL Allen, who considered all but one of the charges provided by retailers for standard asset customers to be reasonable. As with residential and small business customer metering data, all charges considered reasonable by ACIL Allen were included in the QCA's analysis.

ACIL Allen found that there was insufficient information to judge the reasonableness of metering charge data for connection asset customers and individually calculated customers. However, ACIL Allen noted that the metering charges proposed were likely to be immaterial relative to the total electricity bill for those customers.

This is a relatively small dataset, which is to be expected, as there is a much smaller number of large business customers and only one retailer, Ergon Retail, is legally obligated to provide the QCA with information. The QCA would welcome any further data from stakeholders to expand this dataset. Nevertheless, the QCA considers the information provided by retailers for all customers consuming more than 100MWh per annum to be the best dataset obtainable at this time under the current legal framework. Given that the QCA is legally required to set a notified price for large customer meters, our decision will only be binding on Ergon Retail, and large customers have the ability to select their own metering coordinator, we consider the information is sufficient for the QCA to set a notified price for large customer meters.

We understand that retailers treat metering charges as a pass-through to customers. Accordingly, the QCA has not applied a retail margin to metering costs. As with residential and small business customer tariffs, we propose to present metering charges as separate components of notified prices.

Table 15 shows draft 2018–19 metering charges for large business customers.

Table 15 Draft large business ongoing metering charges for advanced digital meters (type 1–4) (excluding GST)

Customer type	***Meter services charge (c/day/meter)***
Standard Asset Customer	141.078
Connection Asset Customer	328.542
Individually Calculated Customer	506.502

Note: These charges will only be payable by large customers who choose Ergon Retail to appoint their metering coordinator.

6 OTHER ISSUES

This chapter sets out our draft decisions on a range of other issues. Our draft decisions are to:

- *include a five per cent allowance above the estimated efficient costs of supply in south east Queensland for all residential and small business customer tariffs (consistent with the 2017–18 price determination and the Minister's cover letter to the 2018–19 delegation) to reflect the value of the preferential terms and conditions that apply to customers on standard contracts*
- *include an allowance for headroom of five per cent above the estimated efficient costs of supply for all large and very large business customer tariffs in 2018–19 (consistent with the 2017–18 price determination)*
- *consider the pass-through of over- or under-recovered SRES costs incurred during 2017–18—at the time of making our final determination*
- *enable retailers to charge standard contract customers for renewable or environmentally friendly customer retail services, as described in the delegation*
- *continue to allow Ergon Retail to implement the Easy Pay Rewards scheme, as described in the delegation.*

6.1 Standing offer adjustment—residential and small business customer tariffs

Retail competition in the residential and small business market segment is very limited in regional Queensland. This is largely because of the Uniform Tariff Policy (UTP), which delivers a subsidy to Ergon Retail to supply electricity at notified prices. These prices are, in most cases, below the cost of supply. As other retailers do not have access to this subsidy, they typically cannot compete with Ergon Retail's subsidised notified prices.

The Queensland Competition Authority (QCA) uses an N+R bottom-up approach to derive the estimated efficient costs of supplying small customers[113] in south east Queensland, which serves as a basis to set notified prices. This produces price levels that we would expect, on average, to reflect the lowest prices offered by an efficient representative retailer.[114]

To be consistent with the UTP, the QCA needs to set notified prices for small customers in regional Queensland that broadly reflect the expected level of standing offer prices in south east Queensland (see Chapter 2). To achieve this, we need to add an amount to the estimated efficient costs of supply to account for the expected price differential between lowest offers and standing offers in south east Queensland. This adjustment is referred to as a standing offer adjustment. In the 2017–18 price determination, we set the standing offer adjustment at five per cent of the total estimated efficient cost of supply in south east Queensland.

[113] Small customers are residential and small business customers, as well as customers accessing the unmetered supply (excluding street lighting) retail tariff.

[114] An efficient representative retailer which does not adopt a loss-leading pricing strategy where electricity is supplied below cost to attract new customers and/or other products and services are sold to those customers.

For the 2018–19 price determination, the cover letter to the delegation requires us to consider maintaining the standing offer adjustment at the current level (i.e. 5 per cent).[115] Energy Queensland considered the current level (i.e. 5 per cent) to be appropriate.[116]

Retail electricity prices observed in south east Queensland reveal that most retailers' standing offer prices are generally higher than their lowest-priced offers, albeit by varying amounts. The lowest-priced offers of retailers are usually market offers, but can be standing offers.

As part of its submission on the ICP, Canegrowers Isis noted that while it would prefer not to have the standing offer adjustment applied:

> Competitive prices should be applied to ensure the…[standing offer adjustment]…is restricted to within a commercially competitive range. This application would ensure regional areas are not disadvantaged in comparison to SEQ urban customers and, importantly, the spirit of the UTP is upheld.[117]

Canegrowers recommended the QCA take account of the Queensland government endorsed retail price offerings in south east Queensland, and apply the UTP to deliver the same retail price outcome across the Ergon distribution area. It highlighted that the Government had endorsed CS Energy and Alinta Energy's joint venture to supply electricity to residential and small business customers within the Energex distribution area. The arrangement is expected to lower retail electricity prices in south east Queensland by stimulating competition.

Canegrowers reported that Alinta Energy and CS Energy have built a significant customer base from the new arrangement and, with other retailers responding to the competition, the venture is delivering retail prices up to 25 per cent below the standing offer price to customers across the Energex network. It noted that, as CS Energy and Alinta Energy continue to be profitable under the two-year deal, it demonstrates that the generation and retail costs the QCA uses to set Ergon prices are too high, and significantly overstate efficient costs.[118]

The Queensland Council of Social Service (QCOSS) submitted that it was disappointed the Government continued to direct the QCA to use a notional standing offer price as the basis for setting regional electricity prices. It highlighted a number of concerns with this approach:

- There is considerable evidence emerging from other National Electricity Market (NEM) jurisdictions that in the longer term, after standing offer price regulation is removed, the standing offer prices no longer reflect efficient costs of supply.
- Retailers in south east Queensland compete primarily on the basis of market offers, not standing offers.
- Retailers are at liberty to raise their standing offer prices without having a detrimental effect on their competitive positioning in the market.
- A notional standing offer price for south east Queensland no longer represents the typical prices paid by electricity customers in south east Queensland, or an appropriate benchmark on which to gauge efficient, competitive market prices.

[115] The cover letter to the 2018–19 delegation is included in Appendix A.
[116] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 January 2018.
[117] Canegrowers Isis, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 12 January 2018.
[118] Canegrowers, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 19 January 2018.

QCOSS acknowledged that the QCA is required to consider the issues identified in the delegation, and appreciated that the QCA would have to comply with the intent of the Minister's delegation for 2018–19. However, QCOSS also noted that:

> as standing offers prices are likely to continue to deviate from market offers, it would advance the broader methodological question if you considered in your Draft Determination other approaches for setting notified prices in regional Queensland. Consultation on these approaches at this stage would also be informative to future Government decisions regarding an appropriate benchmark for regional prices.[119]

The Queensland Consumers' Association was not in favour of using the price differential between standing and market offers in the south east Queensland market as the standing offer adjustment to apply to notified prices. The Queensland Consumers' Association was concerned that standing offers in south east Queensland do not reflect the efficient costs of supply. It considered that:

- Many customers on standing offers are less price-sensitive and more loyal to their existing retailer than market customers, and this is likely to be reflected in standing offer prices.
- As standing offers are used by many retailers as the base from which discounts are offered for market contracts, there is an incentive for retailers to set the highest possible standing offer price in order to advertise high percentage discounts and other incentives.
- The delegation's assumption that standing offers provide additional value for consumers compared to market offers may not be correct.

The Queensland Consumers' Association considered that if a standing offer adjustment is applied, it should not be greater than five per cent, and would preferably be lower.[120]

CCIQ considered the application of the standing offer adjustment to be '*flawed*'. It submitted that the recent direction from the Australian Government to retailers to, '*move consumers onto market offers, or 'cheaper deals'*', meant that a larger portion of consumers in south east Queensland would now be on market offers. CCIQ considered it would be inequitable to base notified prices on standing offers, as a larger proportion of consumers are on market offers. To correct the methodology, CCIQ proposed that the QCA should:

> determine the median between the standing offer and average market offer to determine the notified price.

CCIQ noted that under this methodology:

> Ergon's customers will be paying higher prices for electricity than would be available in a competitive market. [121]

The Queensland Electricity Users Network (QEUN) submitted that the standing offer adjustment should be removed from all residential and small business tariffs.[122]

[119] QCOSS, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 18 January 2018, p. 2.
[120] Queensland Consumers' Association, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 15 January 2018.
[121] CCIQ, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 16 January 2018.
[122] QEUN, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 17 January 2018.

Origin Energy did not comment on the standing offer adjustment explicitly, but noted that the emergence of new market entrants in 2017–18 had created more competitive tensions in the market. It considered that:

> This has driven retailers to be more aggressive with their discounts which has put upward pressure on the cost to serve.[123]

As discussed at the beginning of this section, to determine notified prices consistent with the definition of the UTP, we need to consider adjusting the estimated efficient costs of supply in south east Queensland to account for the expected price differential between lowest-priced and standing offers. To calculate this price differential, we are required to take into account both market and standing offer prices.

6.1.1 Types of electricity offers

Standing offer prices are the prices that retailers charge under standard retail contracts. These are basic contracts with terms and conditions specified by the National Energy Retail Rules (NERR).[124] In south east Queensland, where prices have been deregulated, standing offer prices are set by retailers. Standard retail contracts are referred to in this report as 'standing offers'.

In contrast, market prices are set by retailers and offered under the terms and conditions of a market retail contract and referred to as 'market offers'. Market retail contracts contain a minimum set of terms and conditions (specified in the NERR[125]). These contracts can also include other terms and conditions that are agreed between the retailer and customer. For example, a market retail contract might offer customers additional discounts based on their billing and payment methods.

6.1.2 Why is there a difference between market and standing offer prices?

There are a number of possible reasons why standing offer prices tend to be higher than market offer prices. Some of the variation may reflect that standing offers often provide terms and conditions that are more favourable to the customer. The premium included in standing offer prices could include compensation to the retailer for accepting the additional costs and risks associated with providing better terms and conditions to customers.

Through market offers, retailers are able to adopt different terms and conditions designed to reduce their costs or risks. This may be what enables retailers to offer lower prices or other incentives to encourage customers to take up market offers. For example:

- Incentivising customers to pay on time can reduce a retailer's bad debt risk, improve its cash flow position and reduce costs.
- Requiring customers to use direct debit payment methods achieves a similar outcome, and many retailers will offer discounts to customers who use it, to reflect the lower risk of default and bad debts.
- Requiring customers to subscribe to online-only (paperless) billing allows retailers to save on printing and postage costs.

[123] Origin Energy, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 16 January 2017.
[124] NERR, rule 12, schedule 1.
[125] NERR, rule 14.

The difference between market and standing offer prices may also be an indication of different pricing strategies whereby retailers target customer segments, according to their preferences, loyalty and sensitivity to price changes.

For example, retailers focusing on a customer segment that is environmentally conscious may incorporate and promote GreenPower Programs[126], for an additional charge, as a feature of their market offers. Retailers may also adopt different pricing strategies in response to the behaviour of their competitors, such as providing loyalty credit that is available to customers only after they have remained with the retailer for a specific period, in order to retain customers.[127]

It is also plausible that, as suggested in some stakeholder submissions, the standing offer adjustment reflects marketing strategies designed to inflate the discounts offered to customers on market offers, without materially changing the bills customers face.

6.1.3 What is an appropriate price differential to apply to efficient costs?

We have considered the following matters when estimating the standing offer adjustment:

- the experience in other jurisdictions with deregulated retail electricity prices
- observed price differentials in the recently deregulated south east Queensland retail electricity market
- the direction in the cover letter to the delegation that the QCA should consider maintaining the standing offer adjustment at the current level.[128]

To simplify the discussion, we refer to markets with deregulated retail electricity prices as 'deregulated markets'.

Experience in other deregulated jurisdictions

In this section, we will discuss the jurisdictional experience of three deregulated retail electricity markets in the NEM, namely Victoria, South Australia (SA) and New South Wales (NSW). We have not discussed the experience of Tasmania and the Australian Capital Territory, as retail price regulation remains in place in these jurisdictions.[129]

Victoria

In a mature market such as Victoria, deregulated since 2009, market offers are priced at a discount to standing offers. At the end of 2017, the AEMC reported that consumers could save between 24 to 30 per cent by switching from a standing to market offer.[130]

In a separate report, the Victorian Essential Services Commission (ESC) noted that:

> Retailers' headline discounts are getting bigger, but the relationship between advertised discounts and the bill a customer can expect to pay is getting weaker. In other words, bigger discounts don't necessarily mean cheaper bills.[131]

[126] GreenPower is a voluntary government accredited program that enables a retailer to purchase renewable energy (via the purchase of Large-scale Generation Certificates (LGCs)) on the customer's behalf.
[127] AEMC, *2016 Retail Competition Review*, 30 June 2016.
[128] The cover letter to the 2018–19 delegation is included in Appendix A.
[129] AEMC, *2017 AEMC Retail Energy Competition Review*, 25 July 2017.
[130] AEMC *2017,* p. 268.
[131] Essential Services Commission 2017, *Energy Market Report*, p. 5.

The ESC highlighted that customers need a range of additional information (in addition to the headline discount) in order to determine whether a market offer could deliver their household the advertised savings.

The ESC also found that a number of different advertised discount offers resulted in the same bill outcome for consumers.[132]

South Australia

When the SA retail market was deregulated in February 2013, the SA Government reached an agreement with AGL (the incumbent first tier retailer) to lower its residential standing offer prices by 9.1 per cent and small business tariffs by 4.5 per cent following deregulation, and to cap increases in the retail component of standing offers for two years.[133]

Since the removal of those restrictions in February 2015, the Essential Services Commission of South Australia (ESCOSA) has reported that market offers are generally priced at a discount to standing offers.

As at 30 June 2017, the average price differential between standing and market offers had increased from 2015–16 to 2016–17, from around 9.6 per cent to 12.7 per cent for residential tariffs and from 9.6 per cent to 13.1 per cent for small business tariffs.

The range for standing offer price differentials in 2016–17 for residential customers was between 2 and 22 per cent, and between 4 and 24 per cent for small business customers.[134]

New South Wales

When the NSW retail market was deregulated in July 2014, small customers on a regulated contract were moved to a 'transitional tariff' for up to two years, after which they would be required to move to a standing or market offer. In the first year of deregulation, the NSW Government approved arrangements that would see the transitional tariff decrease by at least 1.5 per cent from existing standing offer prices. In the second year, average increases in the retail component of the transitional tariff were capped at CPI. As at June 2015, around 20 per cent of electricity customers in NSW remained on transitional tariffs, with the remaining 80 per cent on either standing or market offers.[135]

In a 2017 review on the competitiveness of the retail market in NSW, the Independent Pricing and Regulatory Tribunal (IPART) reported that the annual increase in price differentials between the standing and market offers for residential customers (15 per cent) was more than the cumulative rise in standing offer prices since price deregulation. The average difference between the standing offer and the lowest market offer for residential customers was 10 per

[132] ESC 2017, p. 37.

[133] Weatherill, J & Koutsantonis, T, *Lower prices for South Australia*, media release, Government of South Australia, 18 December 2012, accessed December 2016, http://archives.premier.sa.gov.au/images/news_releases/12_12Dec/energyprice.pdf

[134] Essential Services Commission of South Australia, *Energy Retail Offers Comparison Report 2016–17*, August 2017.

[135] Department of Industry, Resources and Energy, FAQs about electricity price deregulation, New South Wales Government, accessed December 2016, http://www.resourcesandenergy.nsw.gov.au/energy-consumers/energy-sources/electricity/removal-of-electricity-price-regulation-faqs#_why-did-the-_n_s_w-_government-remove-retail-electricity-price-regulation__003f

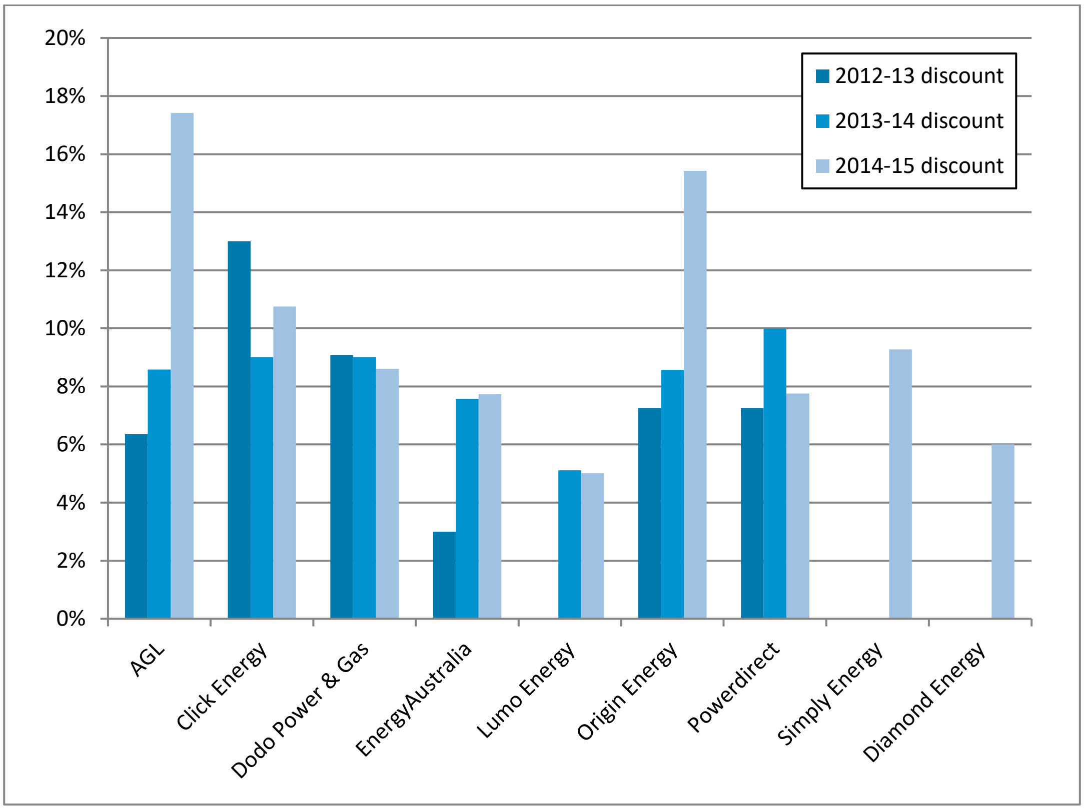
cent to 15 per cent for a typical customer[136] in 2015–16. In 2016–17, this had increased to an average difference of around 23 per cent.[137]

Observed price differentials in south east Queensland

In 2015–16, prior to deregulation in south east Queensland, we published Figure 13 to illustrate the range of discounts offered to residential customers in previous years. The largest generally-available effective discount in 2015–16 was 17.4 per cent and the smallest was 5.02 per cent. The median discount in May 2015 was 8.6 per cent, which was consistent with May 2014, but higher than April 2013 (7.3 per cent).

In our analysis of competition in the market, we determined that our historical approach to determining a headroom allowance (5 per cent) for south east Queensland[138] had succeeded in facilitating the development and maintenance of competition.

Figure 13 Effective discounts offered to residential customers (percentage off total bill)



Source: QCA price comparator, retrieved; April 2013, May 2014 and May 2015. Discounts are relative to an annual customer bill based on annual consumption of 4,100 kWh per year at notified tariff 11 prices. Excludes offers available only to solar PV customers. Origin Energy and AGL effective discounts based on inclusion of 'first month free' offer. AGL effective discount includes $50 signup credit.

Note: Simply Energy commenced making offers in south east Queensland in 2014–15, however discounts are available to members of RACQ only. Diamond Energy did not offer discounts prior to 2014–15. In 2012–13, Lumo Energy offered 'Frequent Flyer' points instead of discounts.

[136] Consuming 6,500 kWh.

[137] IPART, *Review of the performance and competitiveness of the retail electricity market in NSW from 1 July 2016 to 30 June 2017*, final report, November 2017, pp. 41–42.

[138] Based on our analysis of discounts offered to residential customers, customer participation and engagement, active retailers and market concentration, and switching rates.

Since 1 July 2016, retail electricity prices have been deregulated in south east Queensland and retailers have been setting their own standing offer prices. During the first year of deregulation, retailers were not allowed to vary these prices once they had been set, unless the variation was to reduce prices.[139]

In 2016–17, we observed standing offer price differentials (defined by the UTP as the difference between a retailer's standing and the lowest offers) of approximately five to seven per cent. At the end of the December 2017 quarter, the standing offer price differentials had increased to 10.6 and 12.1 per cent[140], for residential and small business customers respectively.

We observed that some retailers are continuing to pursue a pricing strategy of providing only one electricity offer in a particular market segment. As retailers are required[141] to provide a standing offer as the default offer (and in addition to any market offers), in these cases the single offer would be both the standing and market offer. The standing offer price differential for these retailers is zero.[142]

Considerations

Evidence from other jurisdictions shows that the price differentials between standing and market offers have increased since 2016–17, and in all cases are higher than the standing offer price differential calculated in south east Queensland. Both between and within the other jurisdictions, there is significant variation in the size of the pricing differential between standing and market offers. The ESC noted that in the Victorian market:

> Traditional economics would suggest that the burgeoning array of offers available in the energy market represents retailers' efforts to match their service offerings to different customers' preferences. On the other hand consumer psychologists and behavioural economists have shown the adverse impact of giving customers too much choice – price structures with two or three components have been shown to dissuade many customers from actively engaging with the market. In such situations, customers either avoid making a decision and stick with what's already in place (status quo bias) or they make decisions based on simple rules (heuristics) rather than careful consideration of the options. These latter theories suggest that the complexity of engaging with the retail energy market will see many customers enter or remain on contracts that do not necessarily serve their best interests.[143]

The ESC also concluded that if various advertised discounts (effectively individual retailers' standing offer price differentials) result in the same pricing outcome for customers, then consumers will need more information to determine which offer is best for their household.

Given the limitations and reasoning identified above, we consider the magnitude of the observed price differentials in other jurisdictions are unlikely to be indicative of the expected price differential in south east Queensland in 2018–19. Therefore, we do not consider it appropriate to use these observed price differentials as a direct proxy in our 2018–19 price determination.

[139] National Energy Retail Law (NERL), section 23, as per section 16 of the schedule to the Queensland NERL Act.

[140] Calculated based on data available on the Energy Made Easy electricity offer comparator for tariffs 11 and 20, as at 31 December 2017, and includes all offers published at this time. It includes retailers with a standing offer price differential of zero.

[141] NERL (SA) Act 2011, Part 2, Division 3, section 22.

[142] The following retailers had standing offer price differentials of zero on 31 December 2017: 1st Energy, Diamond Energy, Lumo Energy, Mojo Power, People Energy and Sanctuary Energy.

[143] ESC 2017, pp. 5–6.

The south east Queensland standing offer price differential was substantially lower than the differentials estimated in other states, the former being only 10.6 to 12.1 per cent (residential and small business customers respectively). However, while this range might reflect an accurate standing offer price differential, we are not confident that it reflects only the premium required to provide customers with more favourable terms and conditions. Based on the experiences in other jurisdictions, it would appear that as the market matures the standing offer price differential increases substantially. While this may reflect the more favourable terms and conditions customers benefit from on standing offers, it seems plausible that it also reflects a range of other factors, such as retailer loyalty, customer inelasticity and marketing strategies.

We have also considered the comments in the cover letter to the delegation. The 2018–19 delegation cover letter refers to the government's delegation of 2017–18:

> As you will be aware, the Delegation for the setting of prices in 2017–18 identified that the Government considered that regulated prices for small customers in regional Queensland should broadly reflect the expected prices for small customers on Standing Offers in SEQ. The Government is of the view that a Standing Offer adjustment continues to be an important component of notified prices.[144]

The delegation cover letter then provides the following explanation of why the standing offer adjustment is 'an important component' of notified prices:

> The Government considers that the Standing Offer contract provides additional value for consumers compared to a Market Offer, for example through additional protections to consumers contained in the terms and conditions in a Standing Offer contract, as well as providing a signal for retail competition in regional Queensland. As such, the QCA should give consideration to maintaining the Standing Offer adjustment at the current level.

To summarise, the consolidated list of matters that the government has recommended the QCA consider in determining the standing offer adjustment includes that:

- Notified prices for residential and small business customers should continue to reflect the prices paid by customers on standing offers in south east Queensland.
- The standing offer contract provides additional value for consumers compared to market offers, through additional protections.
- The pricing differential between standing and market offers reflects the value of those additional protections.
- The current level of the standing offer adjustment reflects the differential between standing and market offers in south east Queensland, and the value of those additional protections.
- The current level of the standing offer adjustment should be maintained.

We note that the value of additional protections cannot be both the current level allowed in 2017–18 notified prices (i.e. 5 per cent), and the level observed in the market (10.6–12.1 per cent). Therefore, we are required to exercise our judgement in determining how to reconcile these matters, and what the appropriate standing offer adjustment should be.

QCA position

The experience in other deregulated jurisdictions, and the observed price differentials in the south east Queensland retail market, demonstrate that a price differential exists—with market offers generally priced at a discount to standing offers.

[144] The cover letter to the 2018–19 delegation is included in Appendix A.

While the UTP is clear that notified prices should reflect the prices paid by customers on standing offers in south east Queensland, we have given significant weight to the clarification provided by the Minister in the cover letter, as to the intent of using standing offers as a benchmark in this manner.

The cover letter explains that the intent of using standing offers as the benchmark for notified prices is that the government perceives that customers on standing offers benefit from the preferential terms and conditions provided under a standing offer, and intends for notified prices to provide a signal for competition.

We consider that the Minister's comments expand on the Government's definition and explanation of the UTP. The reason that, *'wherever possible, Standard Contract Customers of the same class should pay no more for their electricity, regardless of their geographic location*'[145], is because the Government considers that a standing offer contract[146] provides additional value for consumers compared to a market offer, and in order to provide a signal for retail competition in regional Queensland.

Therefore, the standing offer adjustment should reflect an appropriate value of the cost retailers bear for providing more favourable terms and conditions and result in notified prices somewhat higher than the efficient cost of supply. Although this does not meet the literal definition of the UTP, it will fulfil the Minister's intent in requiring us to consider applying the UTP.

Adopting a standing offer adjustment that reflects an appropriate value of more favourable terms and conditions creates an additional complication, as we do not know the cost to retailers of providing standing offer terms and conditions. We consider it would be more than the efficient costs of supply in south east Queensland, but less than standing offers in south east Queensland.

Given the potential complexity and uncertainty of estimating how much it costs retailers to provide the preferential terms and conditions in south east Queensland, the relatively short timeframes associated with this 2018–19 notified price determination, and the weight we consider appropriate to give the view of the Minister, we consider it reasonable to maintain the standing offer adjustment at the current level (i.e. 5 per cent of total estimated efficient costs)—as per the Minister's cover letter.

While we have not adopted the alternative methodologies proposed by stakeholders, we note that the draft decision on the standing offer adjustment delivers an outcome that is not dissimilar to what may have resulted from the approaches they put forward. That is, a standing offer adjustment that is more than the efficient costs of supplying market customers in south east Queensland, but less than standing offers in south east Queensland. The tariffs in this draft determination account for the additional value that standing offers provide customers compared to market offers and will provide a clear signal for competition.

We also note that, while the QCA is accustomed to exercising its judgement in considering how decisions will affect stakeholders, the government could improve the transparency and certainty of the price determination process by addressing the misalignment between the literal definition of the UTP and the intent of the standing offer adjustment in any future delegations.

[145] The 2018–19 delegation is included at Appendix A.
[146]The only terms and conditions Ergon Retail is allowed to offer.

6.2 Headroom for large and very large business customer tariffs

Where it is effective, competition generally provides the best means of delivering the goods and services that customers demand at prices that reflect efficient costs.

Under section 90(5)(a) of the Electricity Act, we are required to have regard to the effect of our price determination on competition in the Queensland retail electricity market. We intend to also have regard to the objects of the Electricity Act, which include:

(a) establishing a competitive electricity market in line with the national electricity industry reform process

(b) taking into account national competition policy requirements.

In retail markets where competition is considered feasible, the AEMC recommends that some form of 'headroom' allowance be included as part of regulated retail prices to facilitate competition.[147] The headroom allowance is an amount, in addition to the estimated efficient cost of providing customer retail services, included in regulated prices for the purpose of encouraging customers to engage in the market and seek out more attractive market offers.

While there is very limited competition in the small customer segment of the retail electricity market in regional Queensland, the large customer segment[148] has developed a degree of effective competition, particularly in areas where notified prices more closely reflect the actual costs of supply (i.e. Ergon Distribution east pricing zone, transmission region one).

Retail competition in this market segment can be supported through the inclusion of an appropriate level of headroom as part of notified prices, with the aim of encouraging customers to seek out better market offers. Since the 2012–13 price determination, we have included a headroom allowance of five per cent of total estimated efficient costs to facilitate and encourage competition in the large customer market segment in regional Queensland. Energy Queensland supported competition for regional customers and the continued allocation of a headroom component in notified prices.[149]

Canegrowers ISIS submitted that headroom was, *'a theoretical consideration which is not reasonably applicable in the instance and scale of a public utility.'*[150] It considered that the Government should improve the efficiency of Ergon if it wished to reduce the subsidy it pays to uphold the UTP.

6.2.1 Considerations

It is difficult to assess the impact of more cost-reflective notified prices and the inclusion of headroom in facilitating retail competition. In the large customer market segment in regional Queensland, where notified prices more closely reflect the actual costs of supply in some areas but are well below-cost in other areas, there has been a small increase in the proportion of large and very large customers on market contracts in recent years.

[147] AEMC, *Final Report*, *Advice on best practice retail price methodology*, 27 September 2013.

[148] The large customer market segment consists of Standard Asset Customers (SAC) (Large), Connection Asset Customers (CAC) and Individually Calculated Customers (ICC).

[149] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 January 2018.

[150] Canegrowers ISIS, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19,* 12 January 2018, p. 3.

However, in the Ergon Distribution east pricing zone, transmission region one (where notified prices most closely reflect the actual cost of supply), the proportion of both large[151] and very large[152] customers on market contracts is much higher and has been gradually increasing. In 2012–13, around 73 per cent of very large customers in this area were on market contracts; this figure has increased to 76 per cent as of December 2017.

Despite these developments, some barriers to the development of widespread competition in the large customer market segment remain:

- Setting uniform retail tariffs means that customers in higher-cost areas of regional Queensland are not paying cost-reflective notified prices and some very large customers (specifically Individually Calculated Customers) are paying notified prices based on network charges of Connection Asset Customers, rather than cost-reflective network charges.
- A number of large and very large customers in regional Queensland are still accessing obsolete and transitional tariffs, which are generally not cost-reflective.
- Once large or very large customers accept a market contract, they are not allowed to return to Ergon Retail, which may discourage them from accepting a market offer.[153]

Even if headroom is set at a reasonable level, these barriers are likely to continue to limit the extent to which competition develops throughout regional Queensland in the foreseeable future. However, we consider that it is appropriate to continue to include an allowance for headroom so the level of notified prices does not create a barrier to competition (to the extent possible) and to encourage customers to engage in the market and actively seek out better offers.

QCA position

We consider it reasonable to conclude that the previous approach of including a headroom allowance for large and very large business customers at five per cent of total costs has gradually encouraged and maintained competition in the large customer market segment in regional Queensland, especially in areas where notified prices most closely reflect the actual cost of supply.

In the absence of any further information or compelling reasons to change the level of headroom, our draft decision is to continue to include an allowance for headroom in notified prices for large and very large business customers, and to maintain the allowance at five per cent of total estimated efficient costs.

6.3 Cost pass-through mechanism

Cost pass-through mechanisms are used by regulators to mitigate the risk that the costs allowed for in regulated prices are higher or lower than the actual efficient costs of supply. Cost pass-through mechanisms are usually restricted to events that are outside the control of the regulated entity.

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[151] Large customers are Standard Asset Customers (SAC) (Large), typically consuming more than 100 MWh but less than 4 GWh per annum.

[152] Very large customers consist of Connection Asset Customers (CAC), typically consuming more than 4 GWh but less than 40 GWh per annum and Individually Calculated Customers (ICC), typically consuming more than 40 GWh per annum.

[153] This restriction also applies to any future occupants of the premises (e.g. if the premises are sold or occupied by a new tenant).

For the 2014–15 price determination, we applied a cost pass-through mechanism for the first time to pass through an under-recovery of costs in 2013–14 associated with the SRES.[154] The SRES costs incurred by retailers are determined by the binding small-scale technology percentages (STPs) set by the Australian Clean Energy Regulator.

We continued with this approach for the 2015–16, 2016–17 and 2017–18 price determinations. For the 2017–18 price determination, we applied a negative pass-through of a small over-recovery of SRES costs in 2016–17 into 2017–18 notified prices.

We also previously proposed that the cost pass-through mechanism could be used to account for material differences in network charges, in the event that the charges billed to retailers (usually the AER-approved charges) differed from those used to set notified prices. However, a pass-through for network charges has not been needed to date.

In previous price determinations, we considered that not allowing a 'true-up' of costs resulting from particular events that are outside retailers' control may result in notified prices being out of alignment with the estimated benchmark costs of supply[155], which could deviate from the intent of the UTP.

Canegrowers ISIS supported the inclusion of the cost pass-through mechanism.[156]

QCA position

We will consider passing through the differences in SRES costs, where the amounts provided in the 2017–18 price determination are found to be either under- or over-recovered as a result of differences between the non-binding and binding STPs. We will revisit the need for any pass-through adjustment in our final determination when the binding STP for 2018 is known and the over- or under-recovery of SRES costs can be determined. This approach is consistent with the approach adopted in the 2017–18 price determination.

As stated above, we have previously considered that the cost pass-through mechanism could be used to account for material differences in network charges. However, as the final 2017–18 network charges billed to retailers did not differ from those used to set 2017–18 notified prices, no adjustment is required.

Depending on the regulatory framework that will apply to future price determinations and on whether any changes are made to the UTP or the subsidy arrangements underpinning it, the pass-through provisions discussed here may, or may not, remain appropriate in the future. Therefore, we cannot commit to the continued availability of a cost pass-through mechanism beyond this price determination.

6.4 Enabling additional retailer services and execution of government policy

Under section 91A of the Electricity Act, a retailer must charge standard contract customers the notified price for providing customer retail services, if notified prices apply. This means that retailers operating anywhere other than Energex's distribution area, must offer notified prices.

[154] See Chapter 4 for details on how SRES costs are estimated.

[155] In the 2017–18 price determination, notified prices for residential and small business customers were based on the costs of supply in south east Queensland, and notified prices for large and very large business customers were based on the costs of supply in Ergon Distribution east pricing zone, transmission region one.

[156] Canegrowers ISIS, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 12 January 2018.

An assigned retailer (which includes Ergon Retail)[157] may only provide customer retail services if it is the local area retailer for the relevant geographical area (no existing connection) or both the local area retailer and the financially responsible retailer (existing connection).[158] Customer retail services may only be provided under a standard retail contract (small customers) or under the retailer's large customer standard retail contract (large customers).[159]

This means that as the assigned retailer[160], in order for Ergon Retail to charge customers for additional customer retail services, or to enact its Easy Pay Rewards scheme, these variations to the standard retail contract for small customers must be included in notified prices.

This is why the 2018–19 delegation requires us to consider matters that are effectively Government policy decisions in determining notified prices: for those Government policies to have effect for standard contract customers, they must be incorporated into notified prices.

Additional retailer services

The delegation seeks for the QCA to consider enabling retailers to charge standard contract customers for amounts in accordance with a program or scheme for the purchase of electricity from renewable or environmentally friendly sources[161] if the:

- customer voluntarily participates in the program or scheme
- additional amount is payable under the program or scheme
- retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

Easy Pay Rewards

The delegation also seeks for the QCA to consider continuing to include the Easy Pay Rewards scheme in notified prices.

The Government announced Ergon Retail's Easy Pay Rewards scheme in October 2017, and amended notified prices to give effect to the scheme from 1 December 2017. As described in the delegation, eligible customers are entitled to an annual reward of $75 (residential) or $120 (small business).

To be eligible, customers must agree to three conditions, namely to:

- receive bills electronically
- pay bills either weekly, fortnightly or monthly (as agreed) by direct debit or CentrePay by the due date
- accept bill smoothing.

The Easy Pay Rewards scheme will close on 31 December 2019, and all final bill credits are to be applied by this date.[162]

[157] Assigned retailer means a government owned corporation declared, under section 64C, to be an assigned retailer for Subdivision 2 of Division 12A of Part 2. *National Energy Retail Law (Queensland)* Section 2.
[158] *National Energy Retail Law (Queensland)* section 19C(1)
[159] National Energy Retail Law (Queensland) section 19C(4)
[160] *National Energy Retail Law (QLD) Regulation 2014*, section 5(1)b.
[161] Whether or not those additional amounts are calculated on the basis of the customer's electricity usage.
[162] The 2018–19 delegation is included at Appendix A (p. 4).

This is the first time the QCA has been asked to consider both the additional renewable or environmentally friendly retailer services, and the Easy Pay Rewards scheme.

Energy Queensland noted that the wording provided in the ICP could be improved to provide clarity over the arrangements currently in place for the Easy Pay Rewards scheme.[163]

Both Queensland Farmers' Federation (QFF)[164] and the QEUN noted that the annual reward for small businesses was of extremely limited value. QEUN calculated that it was less than one per cent of the electricity bill for an average small business, or 2.8 per cent for a median regional small business.[165]

QEUN also proposed a number of changes to the eligibility requirements of the scheme.

QCA position

No stakeholder feedback was received with regard to the additional customer retail service activities (and charges). We note the proposed changes will not affect customers' rights to standard contract terms and conditions or notified prices. We consider that as the Government has overall responsibility for Ergon Retail's business, there is no reason for the QCA to refuse to enable the changes proposed with regard to renewable or environmentally friendly retailer services.

We note that while stakeholders provided feedback on the Easy Pay Rewards scheme, comments were focused on policy aspects of the scheme, which are outside the scope of this determination. We have included stakeholder comments in Appendix C, noting that they are out of scope.

The Easy Pay Rewards scheme is a Government policy initiative, and does not affect customer rights to standard contract terms and conditions or notified prices, if they would prefer not to access the scheme. On this basis, we do not consider there is any reason for the QCA to oppose the continued application of the scheme, if Ergon Retail's customers have requested access to the scheme.

[163] Energy Queensland, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 31 January 2018.
[164] QFF, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 15 January 2018.
[165] QUEN, Submission on the QCA interim consultation paper, *Regulated electricity prices for 2018–19*, 17 January 2018.

7 TRANSITIONAL ARRANGEMENTS

The delegation requires that the QCA consider maintaining transitional arrangements for tariffs classed as transitional or obsolete, which include farming and irrigation tariffs.

The QCA proposes to:

- *maintain existing transitional arrangements for tariffs 20 (large), 21, 22 (small and large), 37, 47, 48, 62, 65, and 66*
- *maintain existing transitional periods for tariffs 20 (large), 21, 22 (small and large), 37, 47, 48, 62, 65 and 66*
- *allow all customers access to transitional tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66*[166]
- *maintain transitional and obsolete tariffs at their 2017–18 price levels.*

7.1 Transitional arrangements for transitional and obsolete tariffs

Existing transitional and obsolete tariffs

Some business customers, including farmers and irrigators, are currently supplied under transitional or obsolete tariffs. These are legacy retail tariffs for which there is no corresponding network tariff, and which as a result cannot be determined under an N+R approach.

In previous price determinations, the QCA decided that most of these existing transitional and obsolete tariffs[167] should continue to be available for a transitional period because some customers would face significant financial impacts if they were moved to a standard business tariff.

The delegation requires that we consider maintaining these transitional arrangements and continuing to allow all customers access to transitional tariffs.

Submissions

Canegrowers and Energy Queensland supported the continuation of transitional tariffs.

QCA position

The QCA proposes to maintain transitional arrangements for existing transitional and obsolete tariffs.

Data from Ergon Retail[168] shows that while a number of customers would be better off on standard business tariffs, some customers on existing transitional and obsolete tariffs are paying electricity bills below standard business tariffs and below the cost of supplying them with electricity. We consider it appropriate to maintain transitional arrangements, as some customers would face price impacts if they were immediately moved to the standard business tariffs, which all other businesses in regional Queensland must pay.

[166] Tariffs 37, 47, and 48 are obsolete and not accessible to new customers.
[167] Tariffs 20 (large), 21, 22 (small and large), 37, 47, 48, 62, 65 and 66.
[168] See Appendix E.

7.1.1 Transitional periods

In previous price determinations, the QCA determined that transitional and obsolete tariffs should be maintained for a transitional period to allow time for businesses to prepare for the transition to standard business tariffs, and recoup some of the value of investments made to suit the level and structure of transitional and obsolete tariffs. In the 2013–14 price determination, we determined that tariffs 20 (large), 21, 22 (small and large), 37, 62, 65 and 66 would be made available until 30 June 2020. In the 2017–18 price determination, we determined that tariffs 47 and 48 would be made available until 30 June 2022.

Submissions

The Queensland Farmers' Federation (QFF) supported maintaining transitional arrangements and extending them beyond 2020, arguing that businesses need more time to make the transition to standard tariffs. Energy Queensland supported maintaining the current transitional periods to provide customers with certainty and allow them to make appropriate investment decisions.

QCA position

The QCA proposes to maintain the existing transitional periods established in previous pricing determinations for transitional and obsolete tariffs. We have considered suggestions that transitional periods be extended. The QCA remains of the view that the current transitional periods are appropriate. Businesses will have had up to seven years to prepare for the transition when these tariffs ultimately expire, which the QCA considers to be an adequate period for businesses to adapt their operations to the standard business tariff structures which other regional businesses already face.

In addition to the QCA's considerations, the length of transitional periods was considered by the Queensland Productivity Commission (QPC) in its electricity price inquiry, and the Queensland Government. The Government did not support extending any transitional period[169], and has announced a $10 million regional business customer support package to assist regional businesses on transitional and obsolete tariffs, including farmers and irrigators, to understand their electricity use, minimise their electricity costs and make informed choices about future tariff options.[170]

Given the transitional period for most transitional and obsolete tariffs expires in 2020, we encourage customers on these tariffs to contact their retailer for advice on what the most appropriate tariffs will be for their business, and how best to adapt to standard business tariffs.

7.1.2 Access to transitional tariffs

In the 2013–14 price determination, the QCA decided that all business customers should have access to tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66 throughout the transitional period, subject to individual tariff terms and conditions.[171] We made this decision so that all businesses eligible for these tariffs are treated equitably. In subsequent determinations we noted that we would consider closing access to transitional tariffs to new customers if there was a significant increase in the number of customers accessing transitional tariffs, and thereby an increase in the subsidy paid by taxpayers.

[169] Queensland Government, *Queensland Government response to the Queensland Productivity Commission Electricity Pricing Inquiry*, November 2016, p. 11.
[170] See https://www.dews.qld.gov.au/__data/assets/pdf_file/0018/940032/regional-business.pdf.
[171] Tariff 37 cannot be accessed by new customers, as it was classified as obsolete on 1 July 2007.

In the 2017–18 price determination, we continued to allow open access to transitional tariffs.

Submissions

The QFF strongly supported continued access to transitional tariffs. Canegrowers Isis did not support transitional tariffs being made obsolete in 2018–19, and Energy Queensland supported maintaining the existing transition periods. Canegrowers Isis noted that while many irrigators had moved to tariff 66 in the past year, this was due to concessions offered in response to the drought declaration.

QCA position

The QCA proposes to continue to allow all business customers access to transitional tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66. While data from Ergon Retail shows a number of customers are switching between transitional tariffs, the data does not demonstrate that this behaviour is significantly increasing the subsidy paid by taxpayers. In addition, data from Ergon Retail was consistent with the observation by Canegrowers Isis that a significant number of customers were moving between tariffs in response to specific concessions offered by Ergon Retail in response to the drought declaration.

7.1.3 Escalation of transitional and obsolete tariffs

Transitional and obsolete tariff charges are not determined using an N+R approach like other tariffs. In past price determinations, the QCA's general approach[172] to setting charges for each transitional and obsolete tariff was to adjust the charges based on the percentage change in the charges in the standard business tariff that customers would otherwise pay. We then applied additional escalation factors to these increases to limit charges for transitional and obsolete tariffs falling further below cost in dollar terms.[173] Escalation factors of 1.1, 1.25 or 1.5 were applied, depending on the gap between customer bills under transitional and obsolete tariffs and corresponding standard business tariffs. Where the largest proportion of customer bills would likely be impacted by 10 per cent or less, an escalation factor of 1.1 was applied; where impacts were between 10 per cent and 100 per cent, an escalation factor of 1.25 was applied; and where impacts exceeded 100 per cent, an escalation factor of 1.5 was applied. Transitional and obsolete tariffs were escalated on this basis in 2017–18.

Submissions

Canegrowers Isis and the QFF highlighted concerns about the level of electricity prices, especially the impact that electricity prices had on the international competitiveness of irrigation businesses on transitional tariffs. Energy Queensland supported applying an appropriate escalation factor to reduce the attractiveness of these tariffs over time, while avoiding significant price impacts on customers. Energy Queensland noted that applying an appropriate escalation factor would also put downward pressure on the level of subsidy customers receive over time.

[172] In the 2015–16 determination, charges in standard business tariffs fell slightly. We determined that maintaining charges in transitional and obsolete tariffs at their 2014–15 levels would be sufficient to limit these charges from falling further below cost in dollar terms.

[173] As any given percentage increase in a higher bill (such as for a standard business tariff) will be greater, expressed in dollar terms, than the same percentage increase in a smaller bill (such as for a transitional or obsolete tariff). For example, if two bills of $1,000 and $2,000 each increased by 10 per cent to $1,100 and $2,200 respectively, the dollar difference between them would increase from $1,000 to $1,100.

QCA position

The QCA proposes to maintain transitional and obsolete tariffs at their existing price levels. Given that standard business tariffs are forecast to decrease, we consider increasing transitional prices, or applying escalation factors, is unnecessary as the reduction in standard business tariffs will act to somewhat reduce the difference between transitional and standard business tariffs in dollar terms.

Our proposed approach is consistent with our 2015–16 price determination, where standard business tariffs also decreased.

The QCA acknowledges the comments made by irrigators about the impact of prices on their businesses. These impacts are the reason the QCA established transitional arrangements, and the transition period was established based on the depreciable life of irrigation infrastructure—in consultation with these groups.

7.2 Conclusion on transitional arrangements

Table 16 outlines our proposed transitional arrangements for 2018–19.

Table 16 Transitional arrangements for 2018–19

Obsolete or transitional tariff	*Years to be retained*	*2018–19 price change (%)*
Tariff 20 (large)—transitional	2	0
Tariff 21—transitional	2	0
Tariff 22 (small and large)—transitional	2	0
Tariff 37—obsolete	2	0
Tariff 47—obsolete	4	0
Tariff 48—obsolete	4	0
Tariff 62—transitional	2	0
Tariff 65—transitional	2	0
Tariff 66—transitional	2	0

8 DRAFT DETERMINATION

This chapter sets out our draft determination of regulated retail electricity prices (notified prices) to apply from 1 July 2018 to 30 June 2019, as well as draft customer impacts.

Under the network plus retail (N+R) costs approach, retail tariffs are aligned with network tariffs regulated by the AER. For this draft determination, Energex and Ergon Energy have provided draft 2018–19 network tariffs and charges. The network tariffs used to develop retail tariffs are discussed in Chapter 3.

Chapters 4, 5 and 6 set out our decisions on energy costs; retail costs, which comprise the R component of the retail tariff calculation; and other issues.

Chapter 7 sets out our draft decisions on notified prices and transitional arrangements for retail tariffs that have been declared transitional or obsolete.

A draft tariff schedule for 2018–19 is provided in Appendix F. The regulated retail tariffs and notified prices are to be published in a tariff schedule, which includes other information, such as the eligibility criteria and terms and conditions for each tariff.

The tables in section 8.1 set out our draft determination of regulated retail tariffs and prices for 2018–19. All tariffs in section 8.1 exclude goods and services tax (GST).

8.1 Notified prices

Table 17 Draft regulated retail tariffs and prices for residential customers (excl. GST), 2018–19

Retail tariff	***Fixed charge[a]***	***Usage charge (peak)***	***Usage charge (flat/off-peak)***	***Demand charge (peak)***	***Demand charge (off-peak)***
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 11—residential (flat rate)	88.770		24.991		
Tariff 12A—residential (time-of-use)[b]	76.621	62.426	21.234		
Tariff 14—residential (time-of-use demand)[c]	45.771		17.322	62.790	9.243
Tariff 31—night rate (super economy)			16.871		
Tariff 33—controlled supply (economy)			20.535		

a *Charged per metering point.*

b *Peak—3 pm to 9.30 pm (December, January and February); off- peak—all other times.*

c *Peak demand—3 pm to 9.30 pm (December, January and February); off-peak demand—3 pm to 9.30 pm (March to November).*

Table 18 Draft regulated retail trial tariffs and prices for residential customers (excl. GST), 2018–19

Retail tariff	***Fixed charge (Band 1)[a]***	***Fixed charge (Band 2)[b]***	***Fixed charge (Band 3)[c]***	***Fixed Charge (Band 4)[d]***	***Fixed charge (Band 5)[e]***	***Usage charge***	***Top up charge[f]***
	$/mth	***$/mth***	***$/mth***	***$/mth***	***$/mth***	***c/kWh***	***$/kWh/ mth***
Tariff 15—residential	37.194	44.355	51.516	58.677	65.838	18.562	4.206

a *Band 1 (no peak summer window (PSW) allowance, where PSW refers to the time period of 4pm–9pm during months November to March).*

b *Band 2 (up to 5 kWh PSW allowance included).*

c *Band 3 (up to 10 kWh PSW allowance included).*

d *Band 4 (up to 15 kWh PSW allowance included).*

e *Band 5 (up to 20 kWh PSW allowance included).*

f *The top up charge only applies to consumption that exceeds the peak summer window consumption cap for the given fixed charge band. Once exceeded, the cap is extended for the month, equal to the new increased peak consumption value and is then reset to the original cap at the start of the next peak month.*

Table 19 Draft regulated retail tariffs and prices for small business and unmetered supply customers, other than street lighting (excl. GST), 2018–19

Retail tariff	***Fixed charge[a]***	***Usage charge (peak)***	***Usage charge (flat/off-peak)***	***Demand charge (peak)***	***Demand charge (off-peak/flat)***
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 20—business (flat rate)	122.890		26.124		
Tariff 22A—business (time-of-use)[b]	122.890	52.529	22.678		
Tariff 24—Business (time-of-use demand)[c]	62.842		18.488	90.072	9.277
Tariff 41—low voltage (demand)	528.715		15.791		23.744
Tariff 91—unmetered			23.953		

a *Charged per metering point.*

b *Peak—10 am to 8 pm on weekdays (December, January and February); off-peak—all other times.*

c *Peak demand—10 am to 8 pm on weekdays (December, January and February); off-peak demand—10 am to 8 pm on weekdays (March to November).*

Table 20 Draft regulated retail tariffs and prices for large business and street lighting customers (excl. GST), 2018–19

Retail tariff	***Fixed charge***	***Usage charge (peak)***	***Usage charge (flat/off-peak)***	***Demand charge (peak)***	***Demand charge (off-peak/flat)***
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 44—over 100 MWh small (demand)	4611.472		14.608		36.674
Tariff 45—over 100 MWh medium (demand)	15515.432		14.608		27.767
Tariff 46—over 100 MWh large (demand)	40157.298		14.583		22.523
Tariff 50—over 100 MWh seasonal time-of-use (demand)[a]	3731.606	14.251	16.757	65.230	11.727
Tariff 71—street lighting[b]	0.420		31.189		

a *Peak demand is charged on maximum metered demand exceeding 20 kW on weekdays between 10 am and 8 pm in summer months (December, January and February). Off-peak demand is charged on maximum metered demand exceeding 40 kW during non-summer months (March to November). Peak usage is charged on all usage in summer months (December, January and February). Off-peak usage is charged on all usage during non-summer months (March to November).*

b *The fixed charge for street lighting applies to each lamp.*

Table 21 Draft regulated retail tariffs and prices for very large business customers (excl. GST), 2018–19

Retail tariff	*Fixed charge*	*Usage charge (peak)*	*Usage charge (flat/off-peak)*	*Connection unit*	*Capacity (flat/off-peak)*	*Demand charge (flat/peak)*	*Excess reactive power charge*
	c/day	*c/kWh*	*c/kWh*	*$/day/unit*	*$/kVA of AD/mth*	*$/kVA/mth*	*$/excess kVAr/mth*
Tariff 51A—over 4 GWh high voltage (CAC 66kV)	25402.872		13.813	10.105	4.652	2.756	4.454
Tariff 51B—over 4 GWh high voltage (CAC 33kV)	18373.122		13.813	10.105	5.561	2.756	4.454
Tariff 51C—over 4 GWh high voltage (CAC 22/11kV Bus)	16859.022		13.817	10.105	6.396	3.417	4.454
Tariff 51D—over 4 GWh high voltage (CAC 22/11kV Line)	15993.822		13.833	10.105	12.459	6.771	4.454
Tariff 52A—over 4 GWh high voltage (CAC STOUD 33/66kV)[a]	12424.872	13.378	13.779	10.105	6.787	12.248	4.454
Tariff 52B—over 4 GWh high voltage (CAC STOUD 22/11kV Bus)[a]	12424.872	13.383	13.783	10.105	4.782	45.014	4.454
Tariff 52C—over 4 GWh high voltage (CAC STOUD 22/11kV Line)[a]	12424.872	13.399	13.799	10.105	8.791	80.540	4.454
Tariff 53—over 40 GWh high voltage (ICC)[b]	15993.822		13.833		12.459	6.771	4.454

a Peak demand is charged on maximum kVA demand during summer peak demand window times (weekdays between 10 am and 8 pm in December, January and February). Off-peak capacity is charged on the greater of either the customer's kVA authorised demand or the actual monthly half-hour maximum kVA demand. The actual monthly maximum demand is measured all year excluding summer peak demand window times (all year excluding weekdays between 10 am and 8 pm in December, January and February). Peak usage is charged on all usage in summer months (December, January and February). Off-peak usage is charged on all usage during non-summer months (March to November).

b Ergon Distribution advised that ICCs do not incur connection unit charges on a network level.

Table 22 Draft transitional and obsolete regulated retail tariffs and prices (excl. GST), 2018–19

Retail tariff	***Fixed charge***	***Min charge***	***Usage rate 1[a]***	***Usage rate 2[b]***	***Usage rate 3[c]***	***Usage rate (flat)***	***Capacity (up to 7.5kw)***	***Capacity (over 7.5kw)***
	c/day	***c/day***	***c/kWh***	***c/kWh***	***c/kWh***	***c/kWh***	***$/kW/yr***	***$/kW/yr***
Tariff 20 (large)—transitional	76.858					37.595		
Tariff 21—transitional		72.631	49.357	46.374	35.303			
Tariff 22 (small and large)—transitional	184.717		49.820		17.543			
Tariff 37[d]—obsolete		30.623	21.807		54.544			
Tariff 62—transitional	78.451		46.516	39.336	16.448			
Tariff 65—transitional	78.003		36.894		20.321			
Tariff 66—transitional	171.915					19.338	37.503	112.759

***a**. Tariff 21—first 100 kWh; tariff 22—7 am to 9 pm Mon. to Fri.; tariff 37—10.30 pm to 4.30 pm; tariff 62—7 am to 9 pm Mon. to Fri., first 10,000kWh; tariff 65—12hr peak.*

***b**. Tariff 21—101 to 10,000 kWh; tariff 62—7 am to 9 pm Mon. to Fri., over 10,000 kWh.*

***c**. Tariff 21—over 10,000 kWh; tariff 22—all other time; tariff 37—4.30 pm to 10.30 pm; tariffs 62 & 65—all other times.*

***d**. Tariff 37 became obsolete on 1 July 2007. It is only available to customers taking continuous supply under tariff 37 from 30 June 2007.*

Table 23 Draft obsolete high voltage regulated retail tariffs and prices (excl. GST), 2018–19

Retail tariff	*Fixed charge*	*Usage charge (flat/off-peak)*	*Demand charge (off-peak/flat)*
	c/day	*c/kWh*	*$/kW/mth*
Tariff 47—obsolete	44689.726	12.446	27.864
Tariff 48—obsolete	46712.140	12.874	28.822

8.2 Customer impacts

How will the QCA's draft determination impact on customer bills?

The QCA's draft determination will not affect customer bills. The prices discussed in our draft determination are indicative only. To illustrate the hypothetical impacts of these draft notified prices, we compare the annual amount typical customers would have paid under 2017–18 notified prices with the annual amount they would potentially pay under the draft 2018–19 notified prices.

The draft determination forecasts a fall in notified prices for typical customers. This is largely due to reductions in network costs. While there are also forecast reductions in wholesale energy costs, these are expected to be largely offset by increases in the costs of the LRET.

As discussed in section 8.3, customers will also incur metering charges in addition to the amounts shown in these figures. Customers' metering charges will vary depending on a range of factors, including the type of meter they have installed, the number of different tariffs they use and whether they have a solar photovoltaic (PV) system. As these charges vary from customer to customer, they have not been included in the customer impact analysis in this section.

Impact on residential customers

The main retail tariff for residential customers is tariff 11. Many customers on tariff 11 are also on one of the controlled load tariffs (tariffs 31 and 33).[174]

A typical residential customer on tariff 11 is forecast to pay $35 (2.3 per cent) less for their electricity usage and service fee in 2018–19. For a typical customer supplied through controlled load tariffs 31 or 33 combined with tariff 11, the decrease will be $16 (0.8 per cent) and $33 (1.7 per cent) respectively. However, the impact on each individual will vary according to their consumption.

[174] Controlled load tariffs may be used for appliances such as water heaters and pool pumps. These tariffs are cheaper than tariff 11, as customers are only guaranteed supply for a set number of hours (tariff 31 guarantees supply for 8 hours per day and tariff 33 guarantees supply for 18 hours per day).

Figure 14 Draft impact of the change in notified prices on typical residential customers (incl. GST), 2018–19

Note: The annual bill amounts have been rounded to the closest dollar.

Table 24 Changes in electricity bills in 2018–19 for tariff 11 customers (incl. GST)

Description	*Annual consumption (kWh)*	*2017–18 annual bill ($)*	*2018–19 draft annual bill ($)*	*Changes ($)*	*Changes (%)*
25th percentile usage[a]	2554	$1,077	$1,059	$(19)	–1.7
Median usage[b]	4184	$1,542	$1,507	$(35)	–2.3
75th percentile usage[c]	6547	$2,215	$2,156	$(58)	–2.6

a *One-quarter of regional Queensland customers will use less electricity than the 25th percentile customer.*

b *Half of regional Queensland customers will use less electricity than the median customer.*

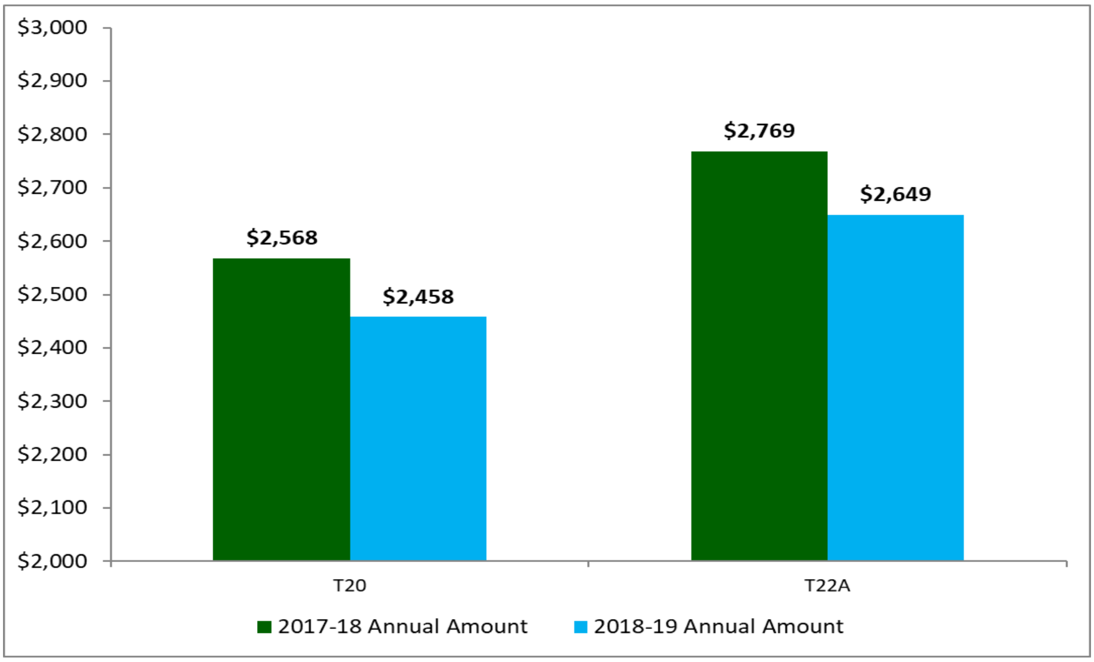
c *Three-quarters of regional Queensland customers will use less electricity than the 75th percentile customer.*

Notes: 25th percentile, median and 75th percentile usage data for regional Queensland customers are supplied by Ergon Retail, who calculate these figures based on all their customers on the stated tariff(s). See Appendix G for more information. Totals may not add due to rounding.

Impact on small business customers

A typical small business customer on tariff 20 is forecast to pay $110 (4.3 per cent) less for their electricity usage and service fee in 2018–19. A typical small business customer on tariff 22A is forecast to pay $120 (4.3 per cent) less for their electricity usage and service fee in 2018–19. However, the impact on each individual business will vary according to their consumption and, if the customer is on tariff 22A, the pattern of their consumption.

Figure 15 Draft impact of the change in notified prices on typical small business customers (incl. GST), 2018–19

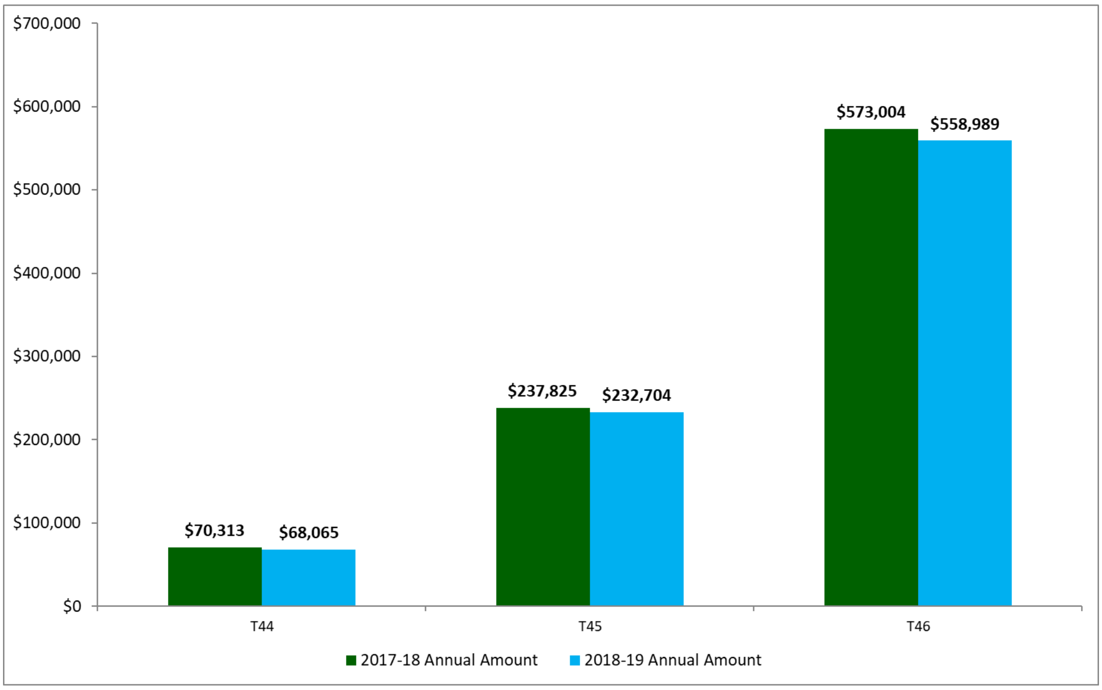


Note: The annual bill amounts have been rounded to the closest dollar.

Impacts on large business customers

A typical large business customer on one of tariffs 44, 45 or 46 is forecast to pay between 2.2 and 3.2 per cent less for their electricity usage and service fee in 2018–19. However, it is important to note that bill impacts for individual customers will vary depending on their level and pattern of consumption.

Figure 16 Draft impact of the change in notified prices on typical large business customers (incl. GST), 2018–19



Note: The annual bill amounts have been rounded to the closest dollar.

What is the QCA's proposed approach to transitional and obsolete tariffs?

Some business customers, including farmers and irrigators, are supplied under legacy retail tariffs. These transitional and obsolete tariffs have been made available for several years to allow customers to transition their businesses to standard business tariffs. The delegation requires that the QCA consider maintaining these arrangements.

The prices of these tariffs cannot be determined under the standard methodology, as there is no network tariff on which to base network costs. The QCA proposes to maintain transitional and obsolete tariffs at their 2017–18 price levels. Given that standard business tariffs are forecast to decrease, we consider increasing transitional prices, or applying escalation factors, is unnecessary, as the reduction in standard business tariffs will act to somewhat reduce the difference between transitional and standard business tariffs in dollar terms. This approach is consistent with our 2015–16 price determination, where standard business tariffs also decreased.

Given the transitional period for most transitional and obsolete tariffs expires in 2020, we encourage customers on these tariffs to contact their retailer for advice on the most appropriate tariffs for their business and the best way to adapt to standard business tariffs.

Table 25 Draft transitional arrangements for 2018–19

Obsolete or transitional tariff	*Period to be retained (years)*	*Proposed 2018–19 price increase (%)*
Tariff 20 (large)—transitional	2	0
Tariff 21—transitional	2	0
Tariff 22 (small and large)—transitional	2	0
Tariff 37—obsolete	2	0
Tariff 47—obsolete	4	0
Tariff 48—obsolete	4	0
Tariff 62—transitional	2	0
Tariff 65—transitional	2	0
Tariff 66—transitional	2	0

8.3 Metering charges

The majority of electricity customers pay metering charges which reflect the capital cost and operation of their meter. Previously, these charges were passed through by retailers and were not part of notified prices. However, as a result of changes made under the 'Power of Choice' reforms[175], these charges will form part of notified prices in 2018–19.

Residential and small business customers

Under the Power of Choice reforms, advanced digital meters[176] must be installed for residential and small business customers when they need a new meter, or where the customer requests one to be installed. These meters, frequently referred to as 'smart' meters, record data on electricity usage, and in some cases demand, every 30 minutes. Typically these meters can also be read, disconnected, reconnected and reconfigured remotely. Over time these meters will replace existing 'accumulation' meters[177] for all residential and small business customers. Most large business customers already have meters[178] with similar functionality.

The QCA proposes to base charges for both meter types on costs in south east Queensland, in line with the government's UTP. The QCA proposes to base metering charges for accumulation meters on regulated charges set by the AER.[179] Charges for advanced digital meters are not regulated, and as these charges are commercially sensitive, there are no public sources of information on which to base notified prices. As a result, the QCA proposes to base metering charges for advanced digital meters on annual cost data obtained from retailers under section 90A of the Electricity Act.

Tables 26 and 27 shows the draft charges for the residential and small business tariffs for each meter type.

[175] AEMC, http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv.
[176] Type 4 and 4A meters.
[177] Type 5 and 6 meters.
[178] Type 1–4 meters.
[179] As these charges were not available at the time of drafting this report, the QCA has used draft charges supplied by distributors in this draft determination.

Table 26 Draft residential and small business metering charges for accumulation meters (type 5 and 6) (excluding GST)

Description	*Charge type*	*Rate*	*Unit*
Primary tariff meter charge (per tariff) Tariffs 11, 12A, 20, 22A, 22 (small and large), 37, 62, 65, 66	Capital	7.167	c/day
	Non-capital	2.314	c/day
	Total	9.481	c/day
Controlled load meter charge (per tariff) Tariffs 31, 33	Capital	2.150	c/day
	Non-capital	0.694	c/day
	Total	2.844	c/day

Note: These charges do not apply where Ergon Distribution is acting as the deemed metering coordinator. Ergon Distribution's accumulation metering charges (for type 5 and 6 meters) are regulated by the AER.

Table 27 Draft residential and small business metering charges for advanced digital meters (type 4 and 4A) (excluding GST)

Description	*Meter type*	*Daily charge (c)*	*Annual cost ($)*
Primary flat rate tariff meter charge (Tariffs 11 and 20—per tariff)	Type 4 (communications enabled) meter	27.590	100.77
	Type 4A (manually read) meter	43.612	159.29
Primary time-of-use tariff meter charge (Tariffs 12A, 22A, 22 (small and large), 37, 62, 65, 66—per tariff)	Type 4 (communications enabled) meter	27.590	100.77
	Type 4A (manually read) meter	43.612	159.29
Primary demand tariff meter charge (Tariffs 14, 15, 24—per tariff)	Type 4 (communications enabled) meter	27.590	100.77
	Type 4A (manually read) meter	43.612	159.29
Primary tariff[a] with controlled load[b] meter charge—per tariff.	Type 4 (communications enabled) meter	30.749	112.31
	Type 4A (manually read) meter	46.771	170.83

a Tariffs 11, 12A, 14, 15, 20, 22A, 22 (small and large), 24, 37, 62, 65, 66

b Tariffs 31 and 33

Note: Customers who request that a working accumulation meter be replaced with an advanced digital meter may need to pay a metering services charge for the capital component of the working meter that was removed. Customers considering a meter replacement should discuss this with their retailer.

Large business customers

Metering charges for large business customers are not regulated, and as these charges are commercially sensitive there are no public sources of information on which to base notified prices. As a result, the QCA proposes to base metering charges for advanced digital meters on annual cost data obtained from retailers under section 90A of the Electricity Act.

Table 28 shows draft charges for large business customers.

Table 28 Draft large business customer metering charges (excl. GST)

Customer classification	***Meter charge c/day/meter***
Standard asset customer	141.078
Connection asset customer	328.542
Individually calculated customer	506.502

Metering bill impacts

Metering costs will vary for each individual based on the type of customer, the tariff(s) they are using, the type of meter they have, and in some cases when the meter was installed.

At the time of making our draft determination, most regional residential and small business customers were being supplied through accumulation meters. Table 29 provides an indication of the change in bill for these customers, including metering costs for typical tariff 11 and tariff 20 customers. For typical customers on accumulation meters, the decrease in annual bill is slightly lower when metering charges are included—as the draft metering charges for 2018–19 provided by Energex are higher than those charged for 2017–18.

For customers moving to an advanced digital meter, the bill impact changes once metering charges are factored in are more significant (see Table 28)—due to the higher metering charge associated with these meters. For typical tariff 11 customers moving to an advanced digital meter, their overall bill is forecast to increase. For typical tariff 20 customers moving to an advanced digital meter, the forecast decrease in their overall bill lessens significantly. However, stakeholders should note that there is no up-front capital charge for an advanced digital meter, whereas tariff 11 and tariff 20 customers installing a new accumulation meter would face an up-front capital charge of $333.61 (excluding GST).[180]

Table 29 Draft bill impact of the change in notified prices, inclusive of metering charges, on typical residential and small business customers (incl. GST), 2018–19

Tariff(s)	***Accumulation meter (%)***	***Advanced digital meter charge (%)***
Tariff 11	–2.1	2.5
Tariff 20	–4.2	–1.4

[180] https://www.ergon.com.au/retail/residential/tariffs-and-prices/upfront-meter-charges.

GLOSSARY

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
CAC	Connection Asset Customer
CARC	Customer acquisition and retention costs
CCIQ	Chamber of Commerce and Industry Queensland
CER	Clean Energy Regulator
CLP	Controlled load profile
CPI	Consumer Price Index
CSO	Community service obligation
c/day	Cents per day
Energex	Energex Distribution
Ergon Distribution	Ergon Energy Corporation Limited (electricity distribution arm)
Ergon Retail	Ergon Energy Queensland Pty Ltd (electricity retail arm)
Electricity Act	Electricity Act 1994 (Qld)
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
GST	Goods and services tax
GWh	Gigawatt hour
HVL	High voltage line
ICC	Individually Calculated Customer
ICP	Interim consultation paper
IPART	Independent Pricing and Regulatory Tribunal
kWh	Kilowatt hour
kVA	Kilovolt Ampere
kVr	Kilovolt Reactive
LGC	Large-scale generation certificate
LHS	Left hand side
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost
MWh	Megawatt hour
N	Network costs

NECF	National Energy Customer Framework
NEM	National Electricity Market
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
Notified prices	Regulated retail electricity prices
NSLP	Net system load profile
N+R	Network + Retail cost build-up methodology
NSW	New South Wales
PSW	Peak summer window
PV	Photovoltaic
QCA	Queensland Competition Authority
QCA Act	Queensland Competition Authority Act 1997
QCOSS	Queensland Council of Social Service
QEUN	Queensland Electricity Users Network
QFF	Queensland Farmers' Federation
QPC	Queensland Productivity Commission
R	Energy and retail costs
RET	Renewable Energy Target
RHS	Right hand side
ROC	Retail operating costs
RPP	Renewable power percentage
SA	South Australia
SAC	Standard Asset Customer
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale technology certificate
STOUD	Seasonal time-of-use demand
STP	Small-scale technology percentage
UTP	Uniform Tariff Policy

APPENDIX A: DELEGATION

Queensland Government

The Honourable Dr Anthony Lynham MP
Minister for Natural Resources, Mines and Energy

Our Reference: CTS 26070/17

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Queensland 4002 Australia
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Email sdnrm@ministerial.qld.gov.au
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Professor Roy Green
Chair
Queensland Competition Authority
Level 27
45 Ann Street
BRISBANE QLD 4000

Dear Professor Green

Re: Determination of Regulated Retail Electricity Prices for 2018–19

I write to you to issue a Delegation and Terms of Reference (ToR) to the Queensland Competition Authority (QCA) for the determination of regulated retail electricity prices in regional Queensland for 2018–19 under section 90AA(1) of the *Electricity Act 1994.*

The Queensland Government's Uniform Tariff Policy (UTP) and promoting greater levels of retail competition are important considerations when setting regulated retail electricity prices in regional Queensland. While the attached Delegation and ToR for 2018–19 are generally consistent with the approaches in the Delegation and ToR for 2017–18, there are some additional considerations. These include:

- Clarifying the arrangements for regional Queensland customers on Essential Energy's network to ensure they receive the same price protections as other regional customers under the UTP;
- Enabling the QCA to consider the benefits in allowing new customers to access transitional tariffs over the next two years; and
- Continuing the inclusion of Ergon Energy retail's Easy Pay Reward scheme, and allowing Ergon Energy to offer a voluntary tariff trial in 2018-19 based on network tariffs approved by the Australian Energy Regulator.

The deregulation of retail electricity prices for small customers in South East Queensland (SEQ) on 1 July 2016 removed a reference point for the determination of prices in regional Queensland. As you will be aware, the Delegation for the setting of prices in 2017–18 identified that Government considered that regulated prices for small customers in regional Queensland should broadly reflect the expected prices for small customers on Standing Offers in SEQ.

The Government is of the view that a Standing Offer adjustment continues to be an important component of notified prices. The Government considers that a Standing Offer contract provides additional value for consumers compared to a Market Offer, for example through additional protections to consumers contained in the terms and conditions in a Standing Offer contract, as well as providing a signal for retail competition in regional Queensland. As such, the QCA should give consideration to maintaining the Standing Offer adjustment at the current level.

The Queensland Government has committed to the establishment of 'CleanCo' which will involve a restructuring of the two publicly-owned electricity generation companies into three with a strategic portfolio of low and no emission power generation assets. One of the objectives of CleanCo is to increase competition in the wholesale market and the QCA should consider the impact of CleanCo, where relevant, when determining regulated retail electricity prices for 2018–19.

Public consultation is a vital part of the QCA's process for determining retail electricity prices. As such, the ToR requires the Draft Determination to be issued in February 2018. I trust this provides sufficient time to undertake the necessary consultation to support the Draft Determination and to allow for delivery of the Final Determination by 31 May 2018.

If your officers have any questions regarding the Delegation and ToR, please contact Ms Kathie Standen, Acting Deputy Director-General, Energy Division on 07 3181 5113 or via email at: kathie.standen@dews.qld.gov.au.

Yours sincerely

Dr Anthony Lynham MP
Minister for Natural Resources, Mines and Energy

Att: Delegation and ToR – Determination of Regulated Retail Electricity Prices for 2018–19

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

I, Honourable Dr Anthony Lynham, Minister for Natural Resources, Mines and Energy, in accordance with the power of delegation in section 90AA(1) of the *Electricity Act 1994* (the Act), delegate to the Queensland Competition Authority (QCA) the function under section 90(1) of the Act of deciding the prices that a retail entity may charge its Standard Contract Customers for customer retail services in Queensland, other than those in the Energex distribution area, for the tariff year 1 July 2018 to 30 June 2019.

The following are the Terms of Reference of the price determination:

Terms of Reference

1. These Terms of Reference apply for the tariff year 1 July 2018 to 30 June 2019.

2. The QCA is to calculate the notified prices and publish an annual price determination, in the form of a tariff schedule, in accordance with these Terms of Reference.

3. In accordance with section 90(5)(a) of the Act, in making a price determination for each tariff year the QCA must have regard to the matters set out in paragraph 5 of these Terms of Reference.

4. In accordance with section 90(5)(b) of the Act, the QCA may have regard to any other matter that the QCA considers relevant.

5. The matters that the QCA is required by this delegation to consider are:

   (a) On 1 July 2016, price regulation in the Energex distribution area was removed for small customers. This means that notified prices do not apply to customers in the Energex distribution area;

   (b) Uniform Tariff Policy - QCA must consider the Government's Uniform Tariff Policy, which provides that, wherever possible, Standard Contract Customers of the same class should pay no more for their electricity, regardless of their geographic location;

   (c) Framework – use of the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by the QCA;

(d) When determining the N components for each regulated retail tariff:

(i) For residential and small business customer tariffs (with the exception of Tariffs 12A, 14, 22A and 24) - basing the network cost component on the network charges to be levied by Energex and the relevant Energex tariff structures;

(ii) For Tariff 12A (residential time-of-use), Tariff 14 (residential seasonal time-of-use), Tariff 22A (small business time-of-use) and Tariff 24 (business seasonal time-of-use demand) - basing the network cost component on the price level of network charges to be levied by Energex, but utilising the relevant EECL tariff structures, in order to strengthen or enhance the underlying network price signals and encourage customers to switch to time-of-use and demand tariffs and reduce their energy consumption during peak times; and

(iii) For large business customers who consume 100MWh or more per annum - basing the network cost component on the network charges to be levied by EECL;

(e) Transitional Arrangements - maintaining transitional arrangements for tariffs classed as transitional or obsolete (i.e. farming, irrigation, declining block, non-domestic heating and large business customer tariffs).

(f) Tariff trial - to offer a voluntary trial tariff, based on the structure of any new cost reflective residential network tariff that is submitted to the Australian Energy Regulator (AER) in the 2018-19 Ergon Energy Pricing Proposal. Ergon Energy will adjust the rates to align with the Uniform Tariff Policy and Long-Run Marginal Cost (LRMC) pricing principles.

(g) Enabling retailers to also charge Standard Contract Customers for the following customer retail service that is not included in regulated retail tariffs:

Amounts in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not those additional amounts are calculated on the basis of the customer's electricity usage), but only if:

(a) the customer voluntarily participates in such program or scheme;
(b) the additional amount is payable under the program or scheme; and
(c) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

(h) Continuing Ergon Energy Queensland Pty Ltd's Easy Pay Rewards scheme to give the following effect:

Easy Pay Rewards

From 1 December 2017, Ergon Energy Queensland Pty Ltd may allow Standard Contract Customers an annual reward of:

- for an eligible residential customer— $75; or
- for an eligible non-residential small customer—$120,

(each, an *annual reward amount*).

To be an eligible customer, a residential or a non-residential small customer must 'opt-in' by agreeing to each of the following (*eligibility requirements*):

- to receive bills electronically (i.e. no paper bills);
- to pay bills either weekly, fortnightly or monthly (as agreed) by direct debit or CentrePay by the due date; and
- to accept bill smoothing.

An eligible customer 'opts-out' if, at any time:

- the customer notifies Ergon Energy Queensland Pty Ltd the customer wants to opt-out; or
- the customer stops agreeing to 1 or more of the eligibility requirements.

The reward scheme will operate as follows:

(a) Ergon Energy Queensland Pty Ltd must allow an eligible customer who has opted in under a Standard Contract to defer payment of the annual reward amount as to that Standard Contract.

(b) The deferred annual reward amount for a Year becomes payable if, within 6 months of opting in, the eligible customer:

(i) opts out; or

(ii) does not maintain payment of bills by direct debit or CentrePay (as relevant).

(c) For an eligible customer, any deferred annual reward amount for a Year ceases to be payable (and not just deferred) on the first anniversary of the commencement of that Year.

(d) An eligible customer, having opted out, may subsequently opt in under the same Standard Contract, provided that:

(i) any deferred annual reward amount payable for that Standard Contract under paragraph (b) has been paid; and

(ii) if no amount is payable under paragraph (b), the customer has not received a deferred annual reward amount within the 12 months before the day the customer opts back into the scheme

(e) The 'Year' for the purposes of the annual reward for an eligible customer commences on the day the customer pays the bill issued after:

(i) The customer opts-in;
(ii) A meter reading is taken with respect to that Standard Contract; and
(iii) A bill is issued with respect to that Standard Contract.

(f) Key Easy Pay Reward dates:

Commencement of Easy Pay Reward: **1 December 2017**
Closure of Easy Pay Reward (final bill credits to be applied by this date): **31 December 2019**

Interim Consultation Paper

6. The QCA must publish an interim consultation paper identifying key issues to be considered when making the price determination.

7. The QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the price determination.

8. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Consultation Timetable

9. The QCA must publish an annual consultation timetable within two weeks after submissions on the interim consultation paper are due, which the QCA can revise at its discretion, detailing any proposed additional public papers and workshops that the QCA considers would assist the consultation process.

Workshops and additional consultation

10. As part of the interim consultation paper and in consideration of submissions in response to the interim consultation paper, the QCA must consider the merits of additional public consultation (workshops and papers) on identified key issues.

Draft Price Determination

11. The QCA must investigate and publish its draft price determination on regulated retail electricity tariffs, with each tariff presented as bundled prices appropriate to the retail tariff structure.

12. The QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the draft price determination.

13. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Final Price Determination

14. The QCA must investigate and publish its final price determination on regulated retail electricity tariffs, with each tariff presented as bundled prices appropriate to the retail tariff structure, and gazette the retail tariffs.

Timing

15. The QCA must make its reports available to the public and, at a minimum, publicly release the papers and price determinations listed in paragraphs 6 to 14.

16. The QCA must publish the interim consultation paper for the 2018–19 tariff year no later than one month after the date of this Delegation.

17. The QCA must publish the draft price determination on regulated retail electricity tariffs in February 2018.

18. The QCA must publish the final price determination on regulated retail electricity tariffs for the 2018–19 tariff year, and have the retail tariffs gazetted, no later than 31 May 2018.

DATED this 18th day of DEC 2017.

SIGNED by the Hon Dr Anthony Lynham,)
Minister for Natural Resources, Mines and Energy) ....
) *(signature)*

APPENDIX B: SUBMISSIONS

Submissions to the interim consultation paper

- Canegrowers
- Canegrowers Isis
- Caravanning Queensland
- Chamber of Commerce and Industry Queensland (CCIQ)
- Cloncurry Shire Council
- Energy Queensland
- Ensby Farming
- Mackay Conservation Group
- Mason, B
- Origin Energy
- Queensland Consumers' Association
- Queensland Council of Social Service (QCOSS)
- Queensland Electricity Users Network (QEUN)
- Queensland Farmers' Federation (QFF)
- Snee, J

One confidential submission.

APPENDIX C: RESPONSES TO ADDITIONAL ISSUES RAISED IN SUBMISSIONS RECEIVED

This section outlines responses we have provided to additional issues raised in submissions received, and which have not been otherwise addressed in this draft determination.

Stakeholder comment	***Stakeholder***	***QCA response***
The QCA should consider the international competitiveness of electricity network costs. Export industries are price takers, all increases must be absorbed which will lead to business closures.	Canegrowers Isis	The QCA must set notified prices in accordance with the requirements of the Electricity Act and the Queensland Government's delegation. Chapter 1 outlines legal requirements that apply to the QCA when it determines notified prices.
Caravan Parks operating embedded networks should be excluded from the large customer tariffs.	Caravanning Queensland	Eligibility criteria for large and small customer tariffs is outside the scope of this report.
Businesses that go on Market and sign a contract with a retailer (other than Ergon) should have the ability to return to Ergon where competitive offers are not available from other retailers.	Caravanning Queensland and QEUN	On 24 October 2017, the Queensland Government announced that Ergon Energy's non-reversion policy would be removed as part of the 'Affordable Energy Plan'.[181] When implemented this would allow small customers to return to Ergon Retail.
The QCA should encourage Ergon to support new mining and large commercial projects by having a 'honeymoon' period, where network charges are reduced to create an incentive for these projects to start in regional areas.	Cloncurry Shire Council	Network charges are a matter for Ergon Distribution and the Australian Energy Regulator.
Depreciated optimised replacement cost (DORC) should be removed from network pricing.	Mackay Conservation Group Snee, J	The approval of network charges, and the cost methodologies used in calculating them, are a matter for Ergon Distribution and the Australian Energy Regulator.
It should be compulsory to supply a full itemised account of credits and debits on the summary of accounts, not bundled into one. In particular each metering charge should be presented separately.	Mason, B	The way metering charges are presented on customer bills is regulated by the Australian Energy Regulator.
The QCA should review retail cost allowances as part of the 2019–20 pricing process.	Queensland Consumers' Association QCOSS	This matter is outside the scope of this report, which concerns notified prices for 2018–19. However, as noted in our 2016–17 determination, the QCA will consider a further detailed review in future, particularly if there are material changes in retail cost drivers.

[181] https://www.dews.qld.gov.au/electricity/affordable-energy-plan

Stakeholder comment	***Stakeholder***	***QCA response***
QCOSS seeks advice and guidance on the current legal and administrative basis for Ergon to charge for metering services (in respect of both smart meters and standard meters).	QCOSS	The basis on which Ergon Retail charges its customers for metering in the 2017–18 tariff year is outside the scope of this report, which concerns notified prices for 2018–19.
The Solar Bonus Scheme must not be added to 2018–19 regulated retail electricity prices/tariffs	QEUN	The Government announced that costs for the solar bonus scheme will be removed from network tariffs for 2018–19. This will be performed by Ergon Distribution. The QCA does not propose adding solar bonus scheme costs to notified prices.
The Queensland Government should inform the AER that the Solar Bonus Scheme will no longer be collected as a jurisdictional levy and charged to electricity customers.	QEUN	Whether costs for the solar bonus scheme are recovered as a jurisdictional levy is a matter for the Queensland Government, Ergon Distribution and the Australian Energy Regulator.
The Queensland Government should reduce Ergon Energy Network charges by reforming network tariffs, in particular increasing the small business customer threshold from 100 MWh per year to 160 MWh per year.	QEUN	Network tariff reform and the small business customer threshold is outside the scope of this report.
The Queensland Government should reduce wholesale prices in Queensland by charging no more than necessary to efficiently operate its 100% Queensland Government owned generators.	QEUN	While government decisions on this matter will impact wholesale prices observed in the market, what operating instructions the Government should give to Government owned generators is outside the scope of this report.
The Queensland Government instructs Ergon Energy to work with consumer advocates on the development of a trial battery tariff for customers with and without solar systems.	QEUN	The QCA has created new tariff types based on Ergon Distribution network tariffs. Development of new network tariff types which could underpin new retail tariffs is a matter for Ergon Distribution.
The process for electricity price reform is flawed and needs a complete review.	QFF	The Queensland Productivity Commission recently completed a comprehensive review on electricity pricing in Queensland and made recommendations to the Queensland Government. Any further review of electricity price reform is a matter for the Queensland Government.
Irrigation electricity tariffs have increased 136 per cent over the past decade, and electricity prices in Australia are higher than overseas jurisdictions. The impacts of rising electricity prices are clearly eroding Queensland's irrigation sector, and Queensland is experiencing a steady decline in the number of irrigation businesses as well as reducing productivity across the sector.	QFF	The QCA must set notified prices in accordance with the requirements of the Electricity Act and the Queensland Government's delegation. Chapter 1 outlines legal requirements that apply to the QCA when it determines notified prices. The Queensland Government has implemented the UTP, which results in a subsidy paid to customers of Ergon Energy Retail to improve affordability and business competitiveness. We have set prices in accordance with the UTP. See Chapter 2. The QCA has also considered affordability by implementing transitional arrangements for legacy tariffs, which smoothes the bill impact for regional customers transitioning to standard business tariffs.

APPENDIX D: NETWORK TARIFF STRUCTURES

This appendix provides further information on the draft decisions in Chapter 3. Energex and Ergon Distribution network tariff structures are compared, and the way tariffs have been adjusted to make them consistent with the UTP is outlined.

Comparison of Energex and Ergon Energy's tariff structures

Table 30 Energex and Ergon Distribution residential and small business customer time-of-use and demand tariffs

Distributor		***Peak***	***Shoulder***	***Off-peak***
Residential (time-of-use)				
Energex	Usage	4 pm–8 pm weekdays (weekdays include government specified public holidays)	7 am–4 pm, 8 pm–10 pm weekdays (weekdays include government specified public holidays) 7 am–10 pm weekends	10 pm–7 am every day
Ergon Distribution (retail tariff 12A)	Usage	3 pm–9.30 pm any day of the week, summer[a] months only		All other times
Residential (time-of-use demand)				
Energex (introduced on 1 July 2016)	Usage	Flat usage charge		
	Demand	4 pm–8 pm workdays (workdays are weekdays but exclude government-specified public holidays)		
Ergon Distribution (retail tariff 14)	Usage	Flat usage charge		
	Demand	3 pm–9.30 pm any day of the week, summer[a] months only		3 pm–9.30 pm any day of the week, non-summer[a] months
Small business (time-of-use)				
Energex	Usage	7 am–9 pm weekdays (weekdays include government-specified public holidays)		All other times
Ergon Distribution (retail tariff 22A)	Usage	10 am–8 pm on summer[a] weekdays		All other times

Distributor		*Peak*	*Shoulder*	*Off-peak*
Small business (time-of-use demand)				
Energex (introduced on 1 July 2017)	Usage	Flat usage charge		
	Demand	9 am–9 pm workdays (workdays are weekdays but exclude government-specified public holidays)		
Ergon Distribution (retail tariff 24)	Usage	Flat usage charge		
	Demand	10 am–8 pm on summer[a] weekdays		10 am–8 pm weekdays in non-summer[a] months

***a**. Summer months are December, January and February.*

Table 31 Energex and Ergon Distribution non–time-of-use tariffs

Type	*Distributor*	*Fixed*	*Usage*		
Residential (tariff 11)	Energex	c/day	Flat rate c/kWh		
	Ergon Distribution	c/day	c/kWh 1st 1,000 kWh/year	c/kWh next 5,000 kWh/year	c/kWh >6,000 kWh/year
Small business (tariff 20)	Energex	c/day	Flat rate c/kWh		
	Ergon Distribution	c/day	c/kWh 1st 1,000 kWh/year	c/kWh next 19,000 kWh/year	c/kWh >20,000 kWh/year
Small business demand (tariff 41)	Energex	c/day	Flat rate c/kWh	$/kVA/month	
	Ergon Distribution	No network tariff			
Night controlled load (tariff 31)	Energex	n/a	Flat rate c/kWh		
	Ergon Distribution	c/day	Flat rate c/kWh		
Controlled load (tariff 33)	Energex	n/a	Flat rate c/kWh		
	Ergon Distribution	c/day	Flat rate c/kWh		
Unmetered (tariff 91)	Energex	n/a	Flat rate c/kWh		
	Ergon Distribution	c/day	Flat rate c/kWh		

Adjusting Ergon Distribution network tariffs

This section outlines the methodology used in section 3.2.3 to adjust Ergon Distribution network charges to reflect Energex price levels, while retaining Ergon Distribution tariff structures. This approach is consistent with the approach we adopted in the 2017–18 determination.

Establishing network prices

To calculate network prices that reflect Ergon Distribution tariff structures and Energex price levels, we used information on network charges provided by the distributors[182], and customer usage data provided by Ergon Distribution and Ergon Retail. Using this data, we then lowered charges under the relevant Ergon Distribution network tariff[183] to a level where the average customer pays the same as they would under the equivalent Energex network tariff.

This calculated network tariff has then been used as the basis of a retail tariff.

Seasonal time-of-use tariffs

Ergon Distribution has seasonal time-of-use network tariffs for residential and small business customers. These network tariffs form the basis of retail tariffs 12A (residential) and 22A (small business). To create retail tariffs that reflect Ergon Distribution network tariff structures, while broadly reflecting Energex price levels, we adjusted all charges under the Ergon Distribution network tariff so that the average customer will pay the same total network cost as they would under the equivalent Energex flat rate network tariff.

The results are shown in tables 32 and 33.

Table 32 Network price options for tariff 12A

	Fixed c/day	*Peak/flat c/kWh*	*Off-peak c/kWh*
Energex 8400	47.900	8.457	-
Ergon Distribution ERTOUT1	135.100	40.498	5.241
QCA-adjusted Ergon Distribution ERTOUT1	36.329	40.498	5.241

Note: Based on data provided by Ergon Distribution and Ergon Retail, annual usage is taken as 5,074 kWh, with 11.48% peak usage and 88.52% off-peak usage.

Table 33 Network price options for tariff 22A

	Fixed c/day	*Peak/flat c/kWh*	*Off-peak c/kWh*
Energex 8500	65.100	9.123	-
Ergon Distribution EBTOUT1	135.100	45.713	9.041
QCA-adjusted Ergon Distribution EBTOUT1	65.100	31.417	6.241

Note: Based on data provided by Ergon Distribution and Ergon Retail, annual usage is taken as 14,560 kWh, with 11.54% peak usage and 88.46% off-peak usage.

[182] Energex and Ergon Distribution.
[183] Network tariffs applying to Ergon Distribution's east pricing zone, transmission region one.

Time-of-use demand tariffs

Ergon Distribution has time-of-use demand network tariffs for residential and small business customers. These network tariffs form the basis of retail tariffs 14 (residential) and 24 (small business). To calculate network prices for these retail tariffs, we uniformly reduced all charges of the relevant Ergon Distribution network tariff to equalise the average customer's network bill with the bill they would face on the equivalent Energex flat rate network tariff.

The resulting network prices are shown in tables 34 and 35.

Table 34 Network price options for tariff 14

	Fixed c/day	***Usage c/kWh***	***Peak demand $/kW/month***	***Off-peak demand $/kW/month***
Energex 8400	47.900	8.457	-	-
Ergon Distribution ERTOUDCT1	10.100	2.751	78.125	11.500
QCA-adjusted Ergon Distribution ERTOUDCT1	6.948	1.893	53.743	7.911

Note: Based on data provided by Ergon Distribution and Ergon Retail, annual usage is taken as 5,074 kWh with a peak demand of 1.45 kW per month and an off-peak demand of 3.51 kW per month.

Table 35 Network price options for tariff 24

	Fixed c/day	***Usage c/kWh***	***Peak demand $/kW/month***	***Off-peak demand $/kW/month***
Energex 8500	65.100	9.123	-	-
Ergon Distribution EBTOUDCT1	10.100	3.416	97.088	10.000
QCA-adjusted Ergon Distribution EBTOUDCT1	7.911	2.676	76.049	7.833

Note: Based on data provided by Ergon Distribution and Ergon Retail, annual usage is taken as 14,560 kWh with a peak demand of 2.91 kW per month with an off-peak demand of 6.86 kW per month.

Non–time-of-use tariffs

As discussed in Chapter 3, we examined the impact of using Ergon Distribution's inclining block tariff structure as the basis for flat-rate retail tariffs 11 (residential) and 20 (small business). For the purposes of this assessment, we calculated network prices by uniformly reducing all charges of the relevant Ergon Distribution network tariff to equalise the total network revenue recovered by Ergon Distribution under an inclining block tariff with the network revenue it would have otherwise recovered under an Energex flat rate tariff. Network prices calculated using this approach are consistent with the UTP.

The resulting network prices and charts demonstrating the impact on customers are shown below.

Table 36 Network price options for tariff 11

	Fixed c/day	*Usage c/kWh*		
		Flat/first block [a]	*Second block [b]*	*Third block [c]*
Energex 8400	47.900	8.457	-	-
Ergon Distribution ERIBT1	135.100	3.213	6.173	10.062
QCA-adjusted Ergon Distribution ERIBT1[d]	99.697	2.371	4.556	7.425

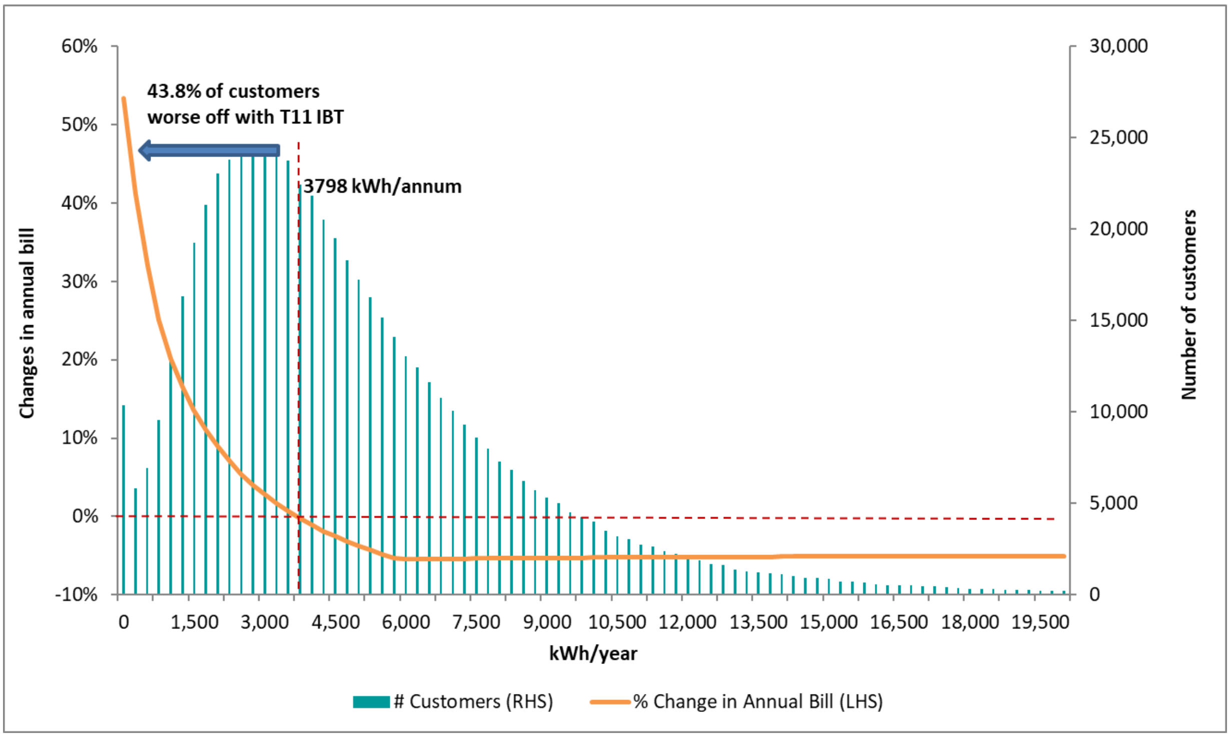
a. *Usage charge applies to all usage under an Energex network tariff (row 1). Usage charge applies to the average usage of less than 2.74 kWh per day under an Ergon Distribution network tariff (rows 2 and 3)*

b. *Usage charge applies to the average usage greater than 2.74 kWh per day and less than 16.43 kWh per day under an Ergon Distribution network tariff (rows 2 and 3)*

c. *Usage charge applies to the average usage above 16.43 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

d. *Network prices were adjusted in a manner such that the relativities between the different pricing components within the tariff are preserved.*

Figure 17 Impact on tariff 11 customers adopting Ergon Distribution inclining block tariff structure



a. *IBT stands for inclining block tariffs.*

b. *RHS stands for right hand side. LHS stands for left hand side.*

c. *43.8% of customers (consuming below 3798 kWh/annum) on average will be worse off moving from a residential flat tariff (tariff 11) to Ergon Distribution inclining block tariff structure.*

Table 37 Network price options for tariff 20

	Fixed c/day	Usage c/kWh		
		Flat/first block [a]	Second block [b]	Third block [c]
Energex 8500	65.100	9.123	-	-
Ergon Distribution EBIBT1	135.100	3.566	8.716	12.711
QCA-adjusted Ergon Distribution EBIBT1[d]	109.739	2.897	7.080	10.325

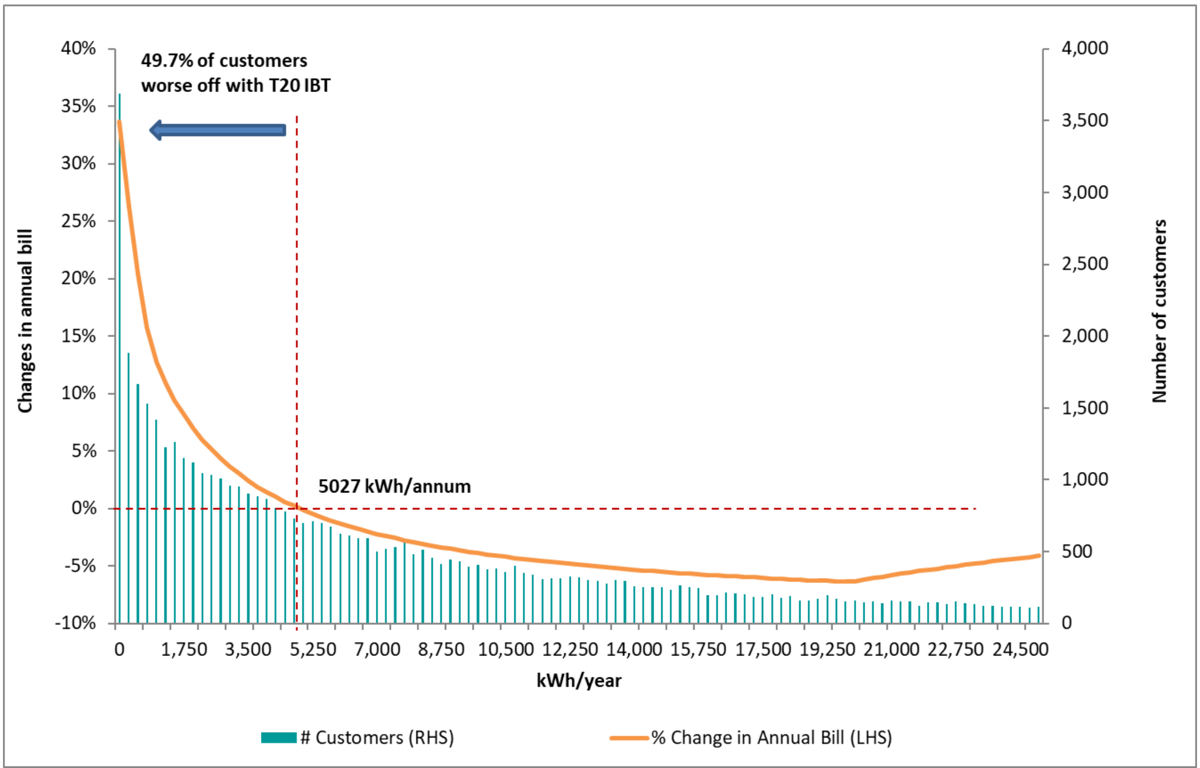
***a**. Usage charge applies to all usage under an Energex network tariff (row 1). Usage charge applies to the average usage of less than 2.74 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

***b**. Usage charge applies to the average usage greater than 2.74 kWh per day and less than 54.76 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

***c**. Usage charge applies to the average usage above 54.76 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

***d**. Network prices were adjusted in a manner such that the relativities between the different pricing components within the tariff are preserved.*

Figure 18 Impact on tariff 20 customers adopting Ergon Distribution inclining block tariff structure



***a**. IBT stands for inclining block tariffs.*

***b**. RHS stands for right hand side. LHS stands for left hand side.*

***c**. 49.7% of customers (consuming below 5027 kWh/annum) on average will be worse off moving from a small business flat tariff (tariff 20) to Ergon Distribution inclining block tariff structure.*

APPENDIX E: TRANSITIONAL AND OBSOLETE TARIFFS—CUSTOMER IMPACTS

In Chapter 7, we discuss our draft decision on arrangements for customers on transitional and obsolete retail tariffs. This decision is based on data provided by Ergon Retail.

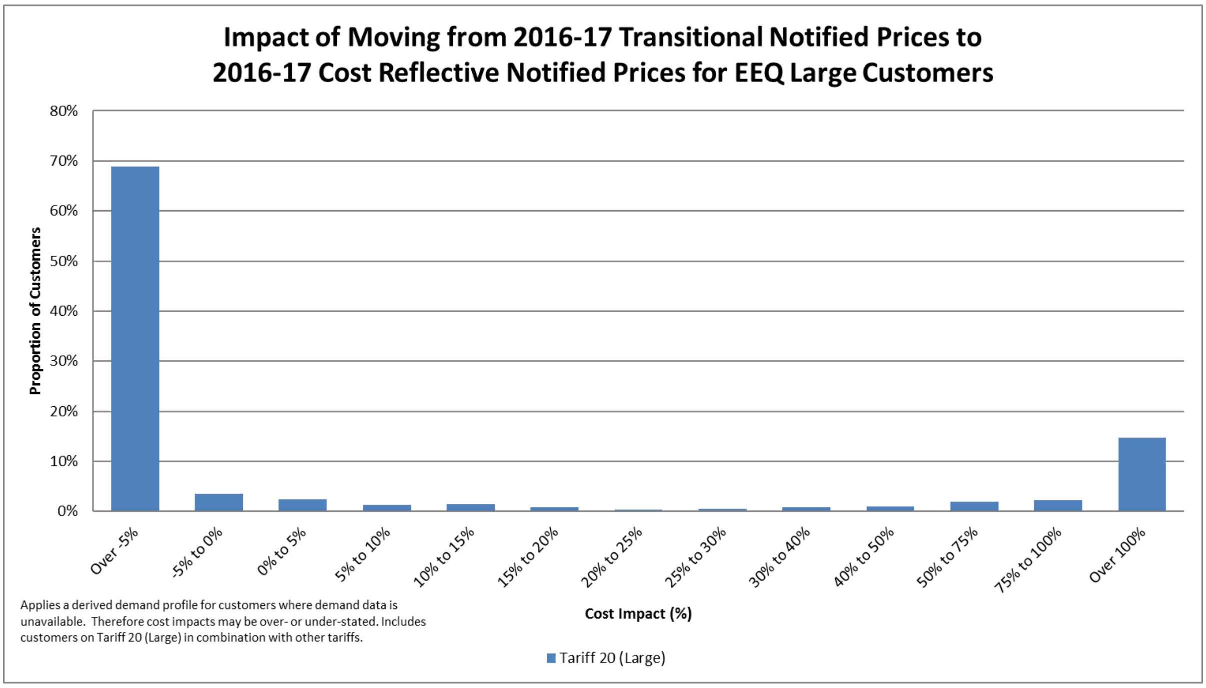
This appendix contains the analysis of bill impacts for customers moving from a transitional or obsolete 2016–17 tariff to an alternative 2016–17 standard business tariff.

The customer impacts are calculated on an individual tariff basis. As some customers are supplied under multiple tariffs, the overall impact to an individual customer may be a combination of the impacts shown below.

Tariff 20 (large)

Transitional tariff 20 (large) aligns with tariffs 44 to 53, which are based on Ergon Energy network tariffs and charges. Figure 19 shows the likely impacts for large business customers moving from this transitional tariff to the most appropriate of the standard large business customer tariffs.

Figure 19 Change in electricity bills for business customers on tariff 20 (large) moving to large customer standard business tariffs

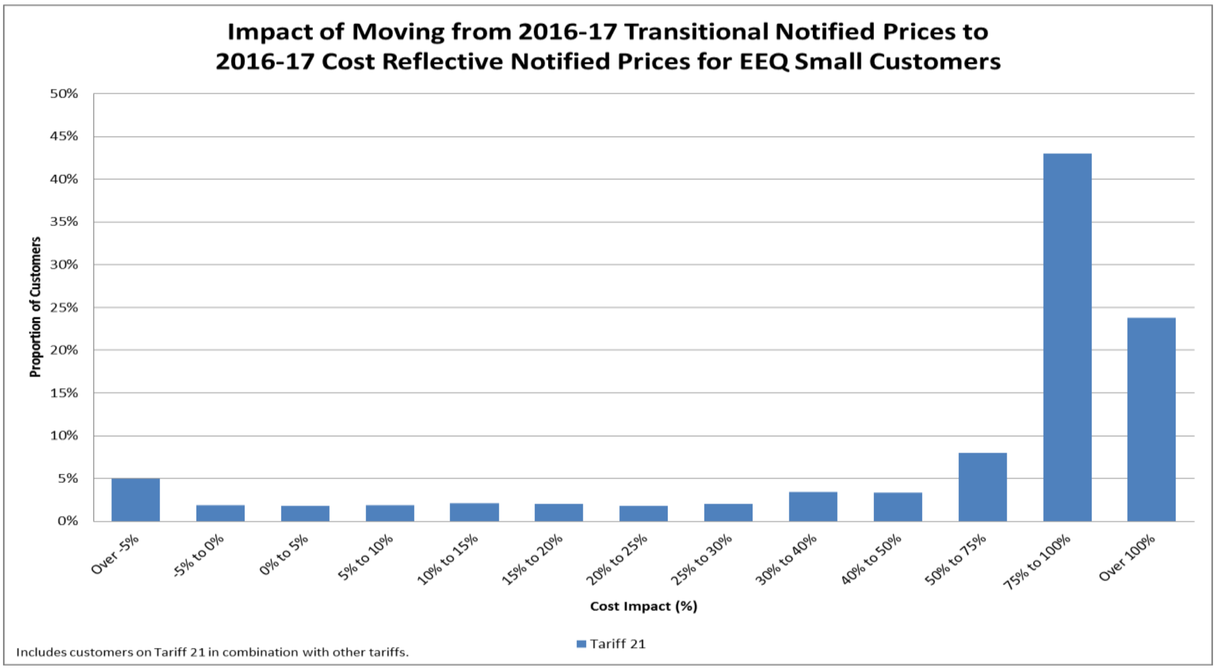


Source: Ergon Retail.

Tariff 21

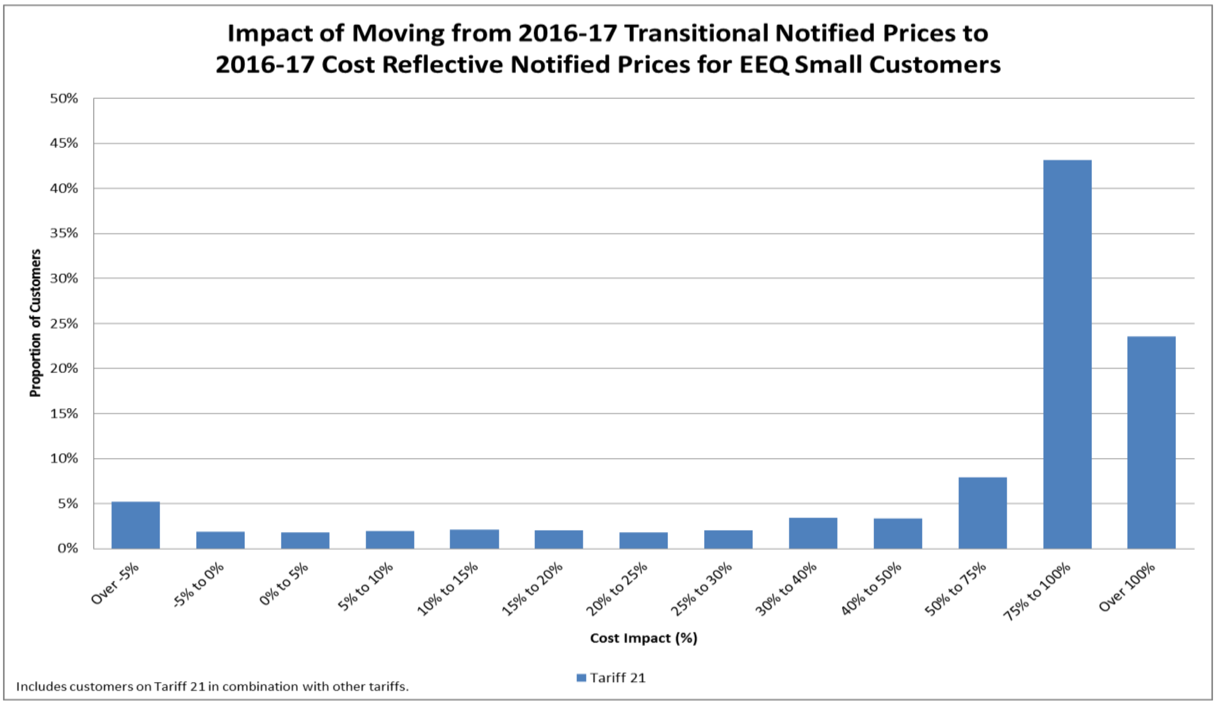
Tariff 21 is a declining block tariff that aligns with tariff 20 for small business customers. Figures 20 to 21 show the distribution of potential impacts for existing customers moving to standard business tariffs.

Figure 20 Change in electricity bills for small business customers on tariff 21 moving to tariff 20



Source: Ergon Retail.

Figure 21 Change in electricity bills for small business customers on tariff 21 moving to tariff 22A

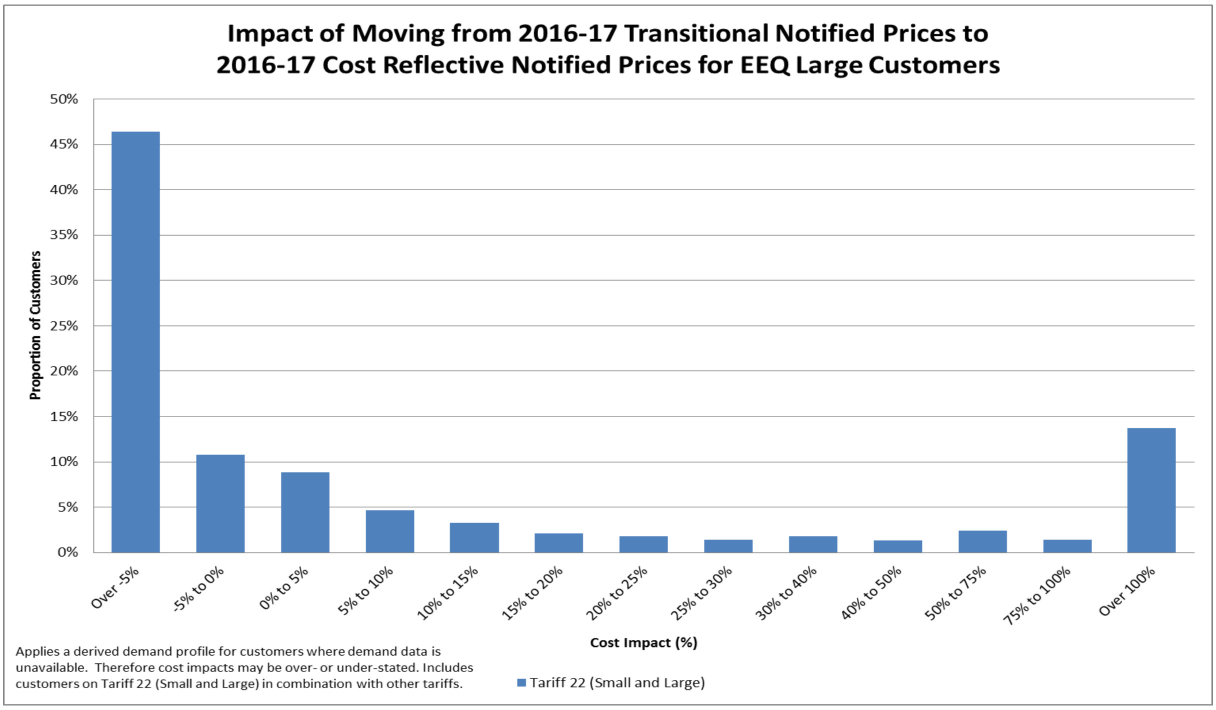


Source: Ergon Retail.

Tariff 22 (small and large)

Transitional tariff 22 (small and large) aligns with tariffs 20 for small business customers and 44 to 53 for large business customers, which are based on Ergon Energy network tariffs and charges. Figure 22 shows the likely impacts for business customers moving from these transitional tariffs to the most appropriate of the standard business customer tariffs.

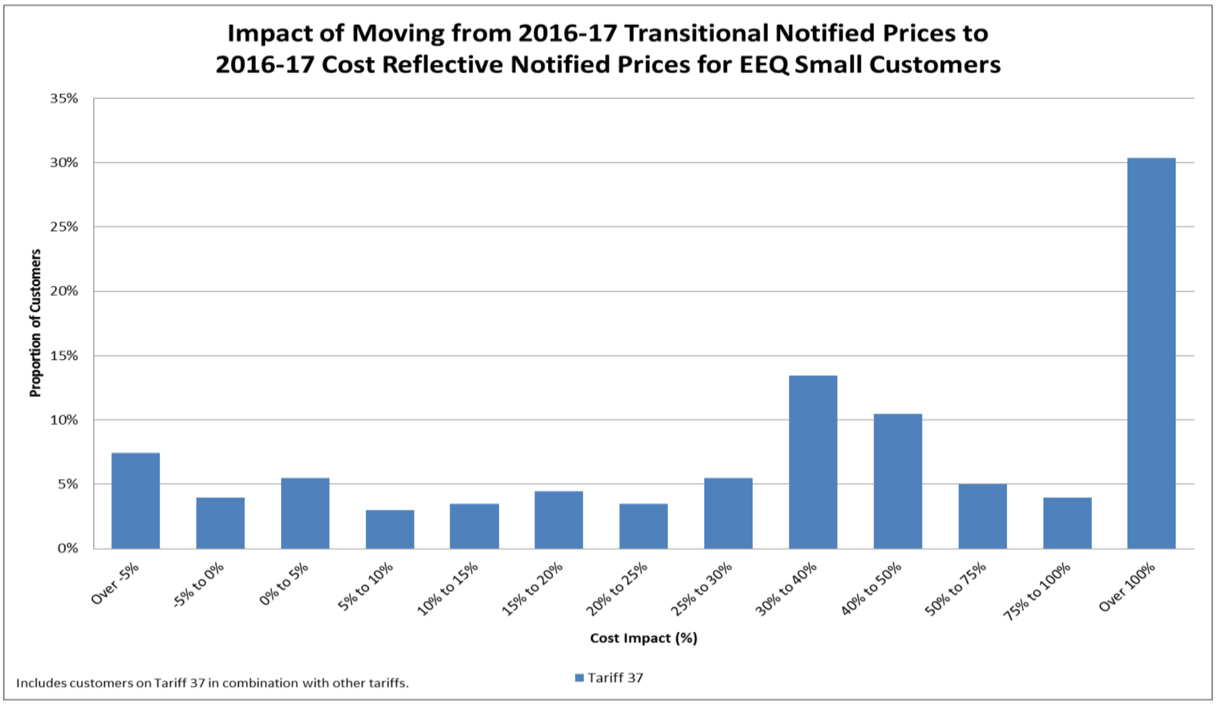
Figure 22 Change in electricity bills for large business customers on tariff 22 (small and large) moving to large customer standard tariffs



Tariff 37

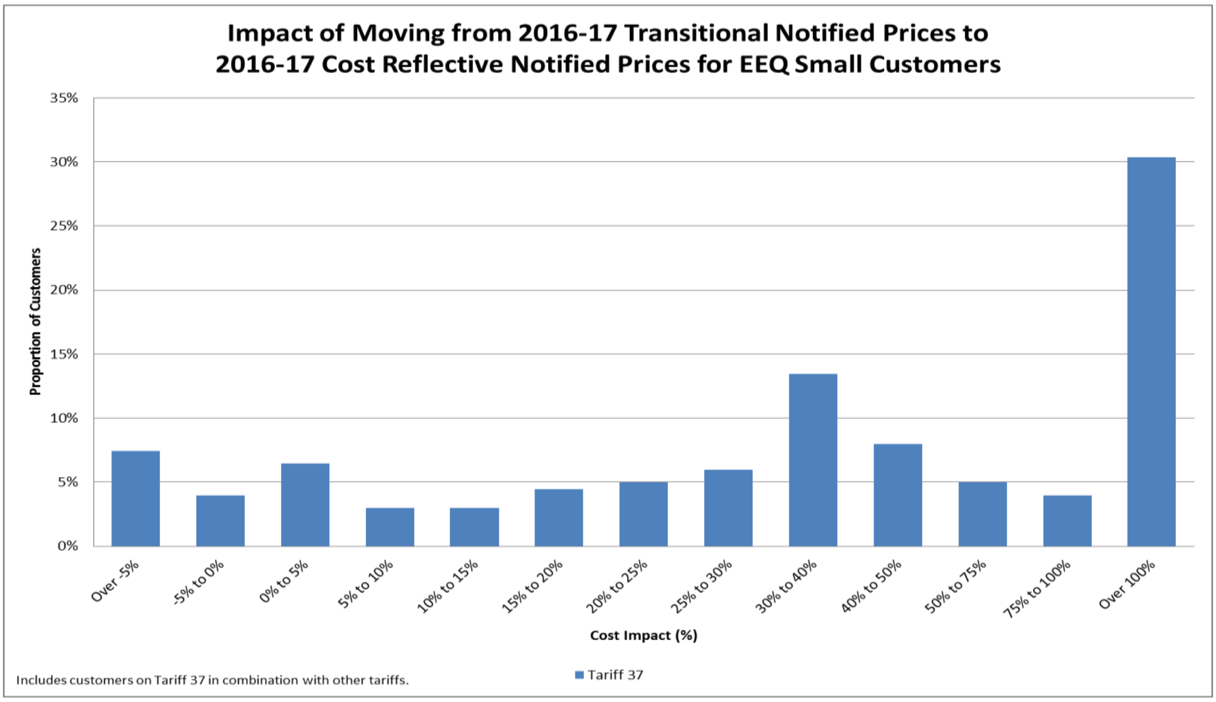
Tariff 37 is a business time-of-use tariff that aligns with tariffs 20 or 22A for small business customers and one of tariffs 44 to 53 for large business customers. Figures 23 to 25 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 23 Change in electricity bills for small business customers on tariff 37 moving to tariff 20



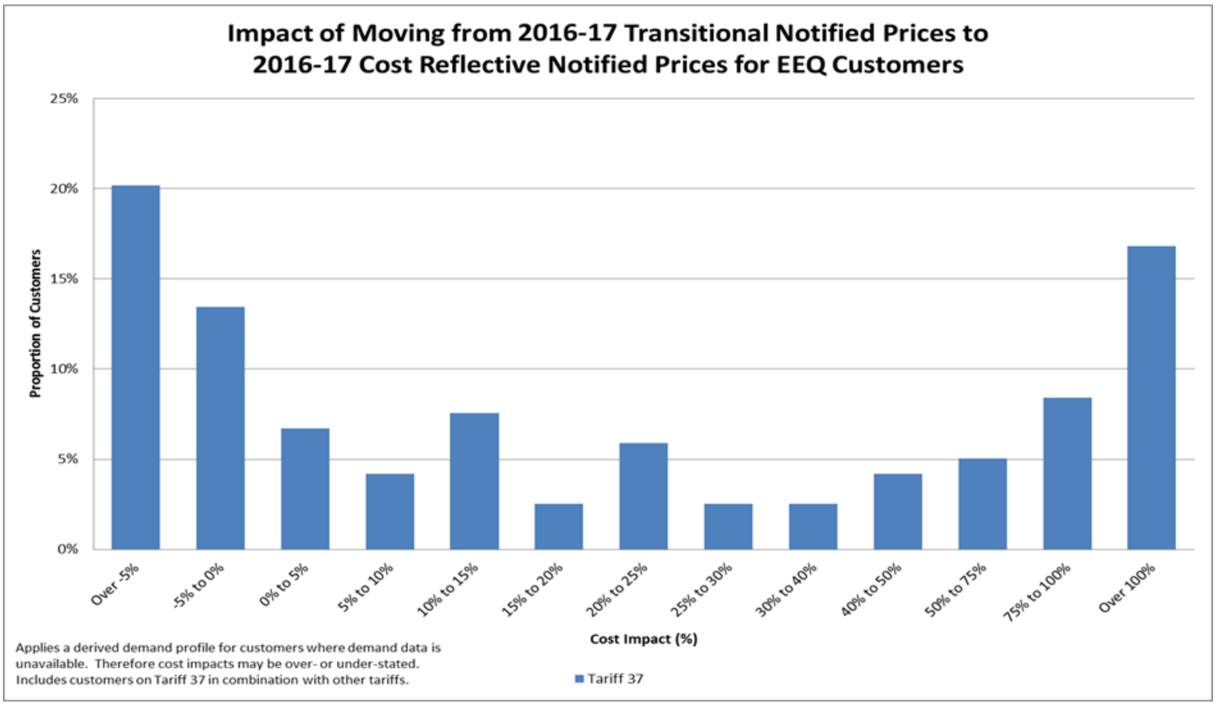
Source: Ergon Retail.

Figure 24 Change in electricity bills for small business customers on tariff 37 moving to tariff 22A



Source: Ergon Retail.

Figure 25 Change in electricity bills for large business customers on tariff 37 moving to large customer standard business tariffs

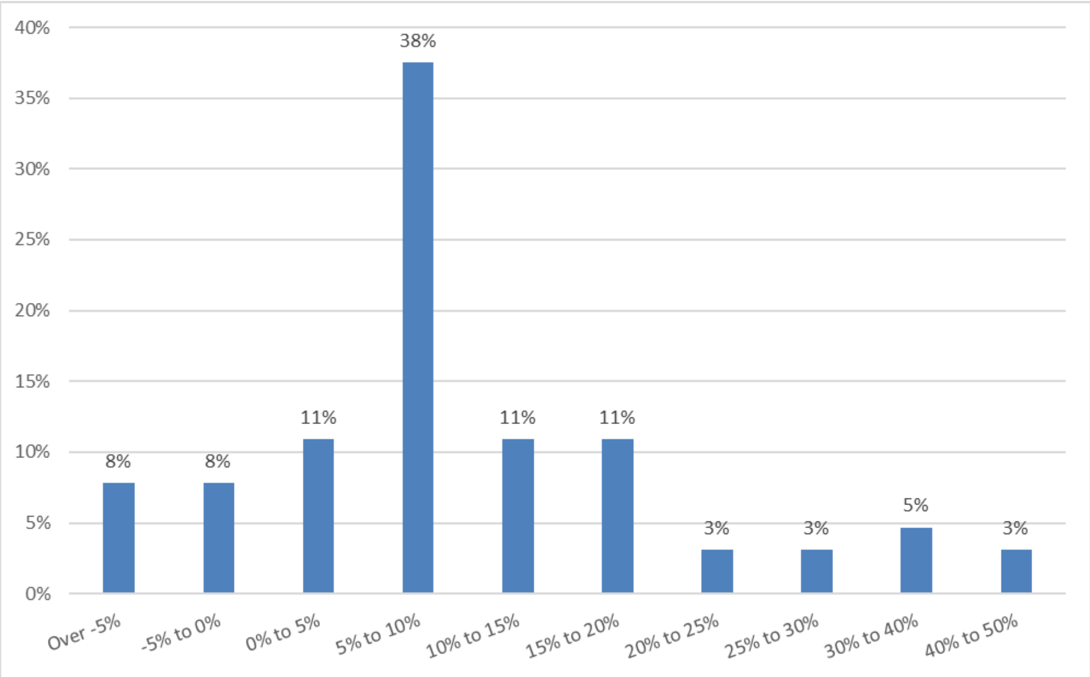


Source: Ergon Retail.

Tariffs 47 and 48

Transitional very large tariffs 47 and 48 align with tariffs 51A–D, 52A–C and 53, which are based on Ergon Energy network tariffs and charges. Figure 26 shows the likely impacts for large business customers moving from transitional tariffs 47 and 48 to the most appropriate standard business tariffs.

Figure 26 Estimated bill impact for customers moving from tariffs 47 and 48 to standard business tariffs

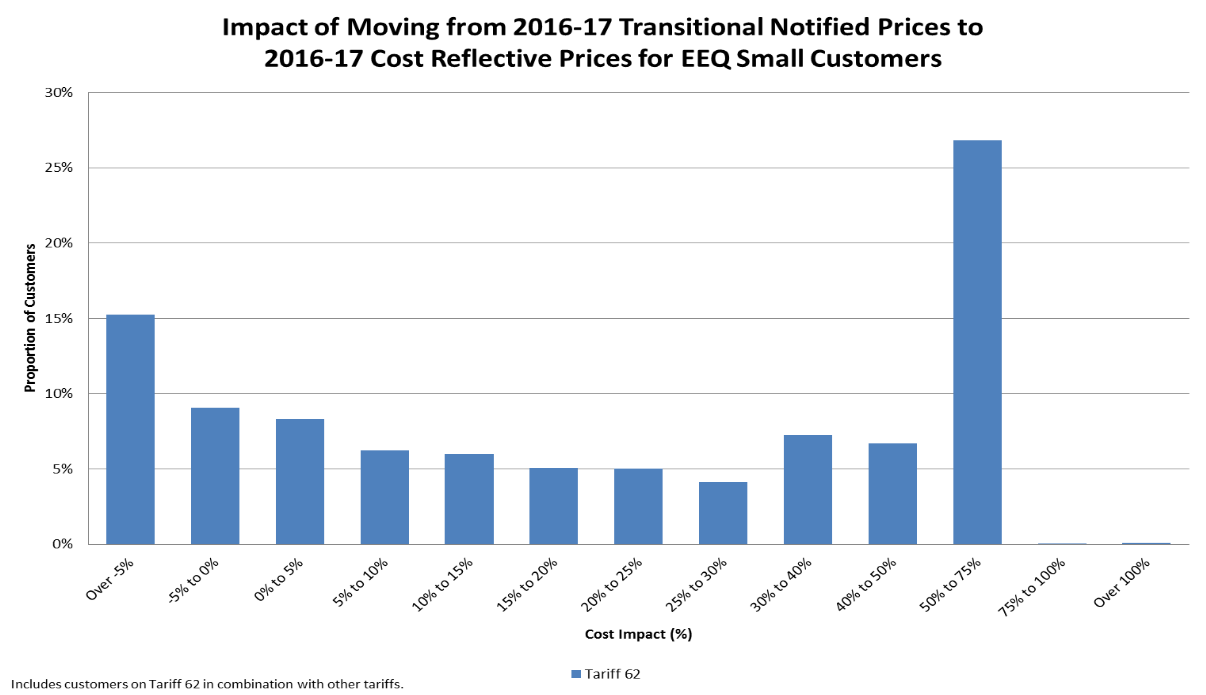


Source: Ergon Retail

Tariffs 62 and 65

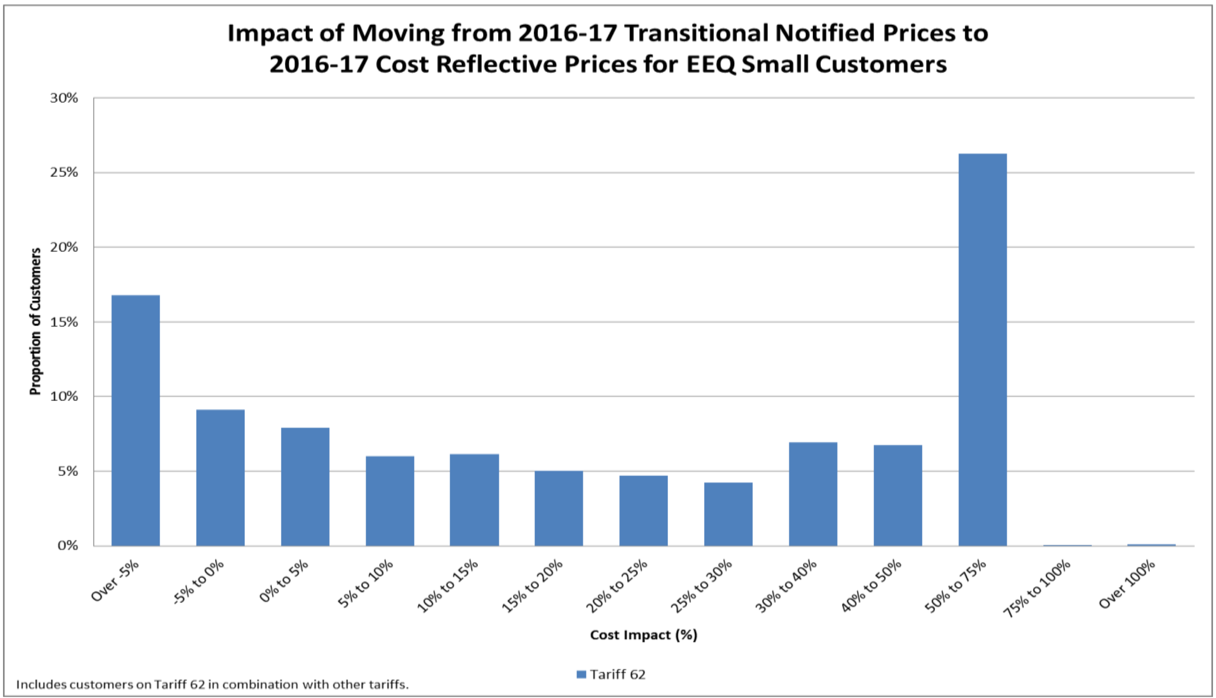
Tariffs 62 and 65 are time-of-use tariffs for farming and irrigation customers. These tariffs align with tariffs 20 or 22A for small business customers and tariffs 44 and 45 for large business customers. Figures 27 to 32 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 27 Change in electricity bills for small business customers on tariff 62 moving to tariff 20



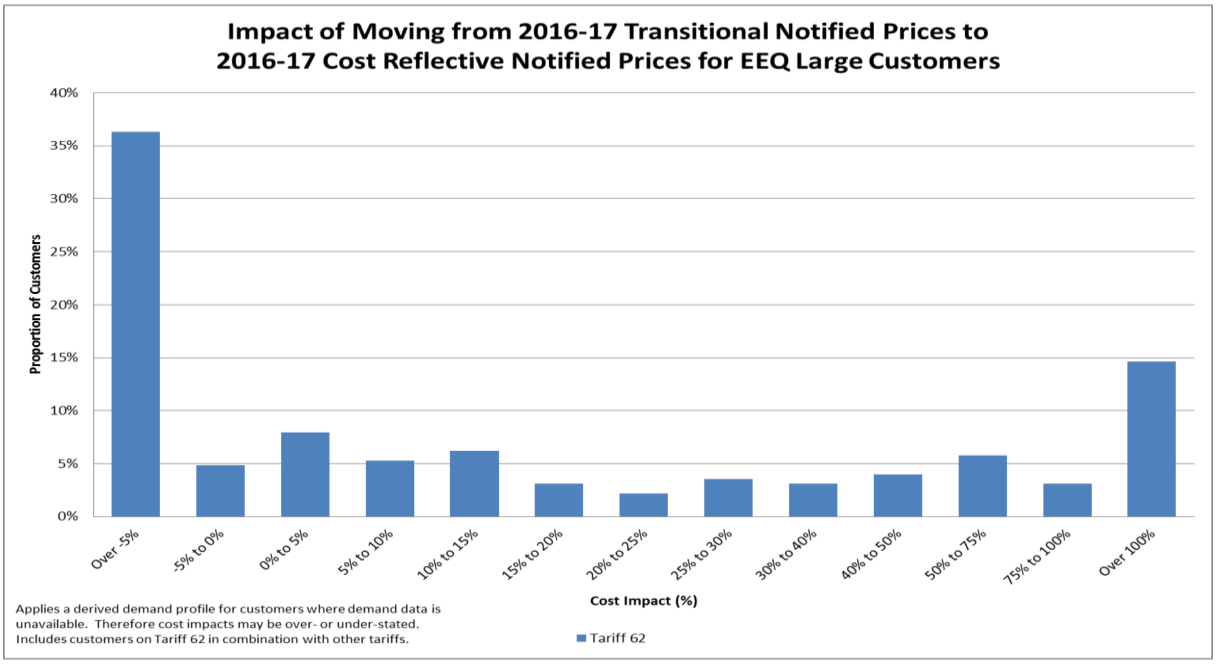
Source: Ergon Retail.

Figure 28 Change in electricity bills for small business customers on tariff 62 moving to tariff 22A



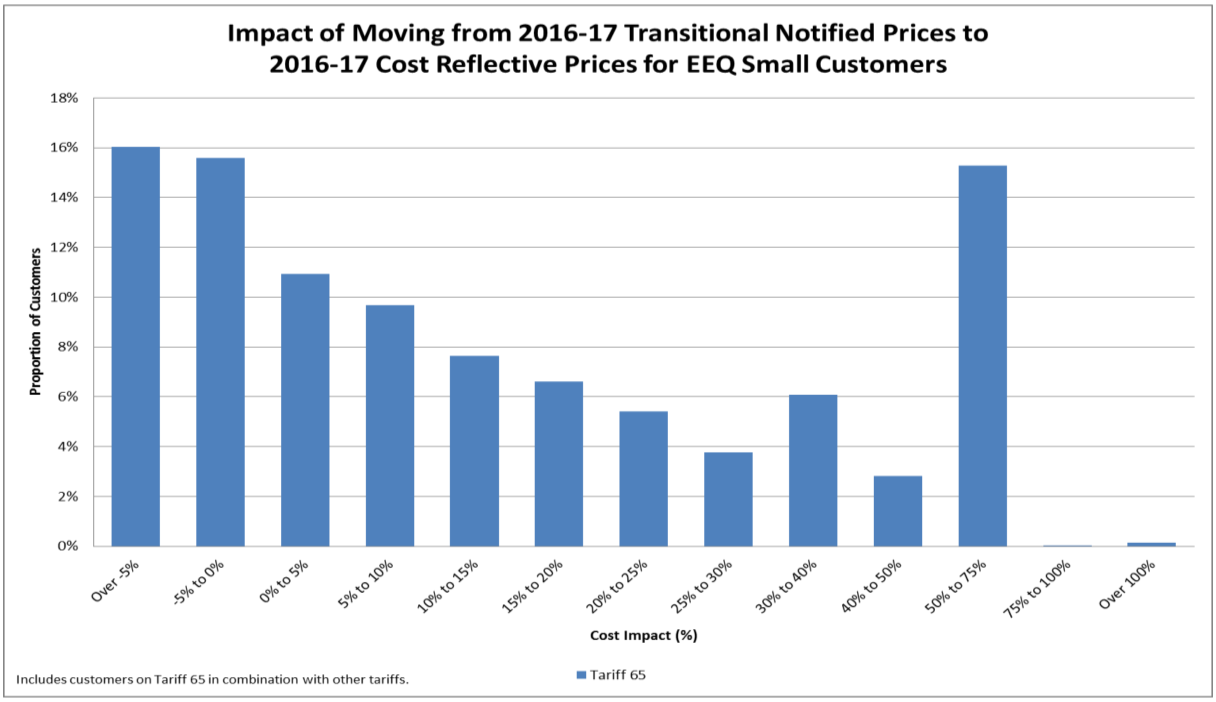
Source: Ergon Retail.

Figure 29 Change in electricity bills for large business customers on tariff 62 moving to large customer standard business tariffs



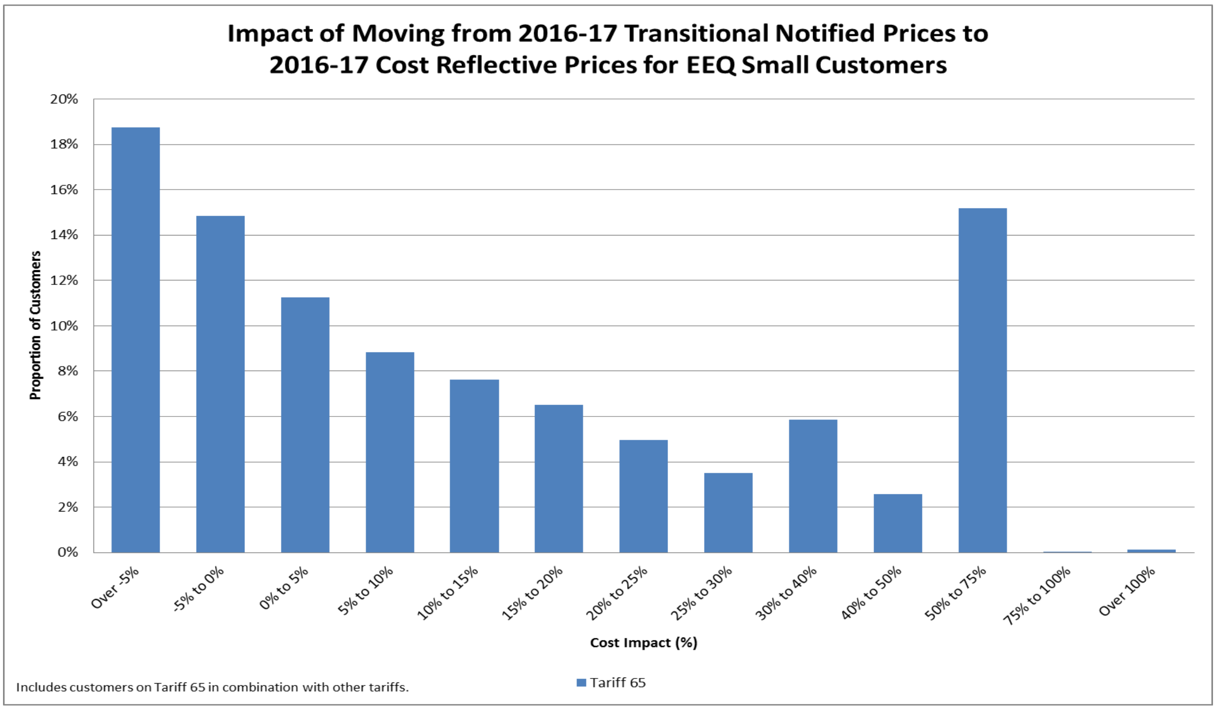
Source: Ergon Retail.

Figure 30 Change in electricity bills for small business customers on tariff 65 moving to tariff 20



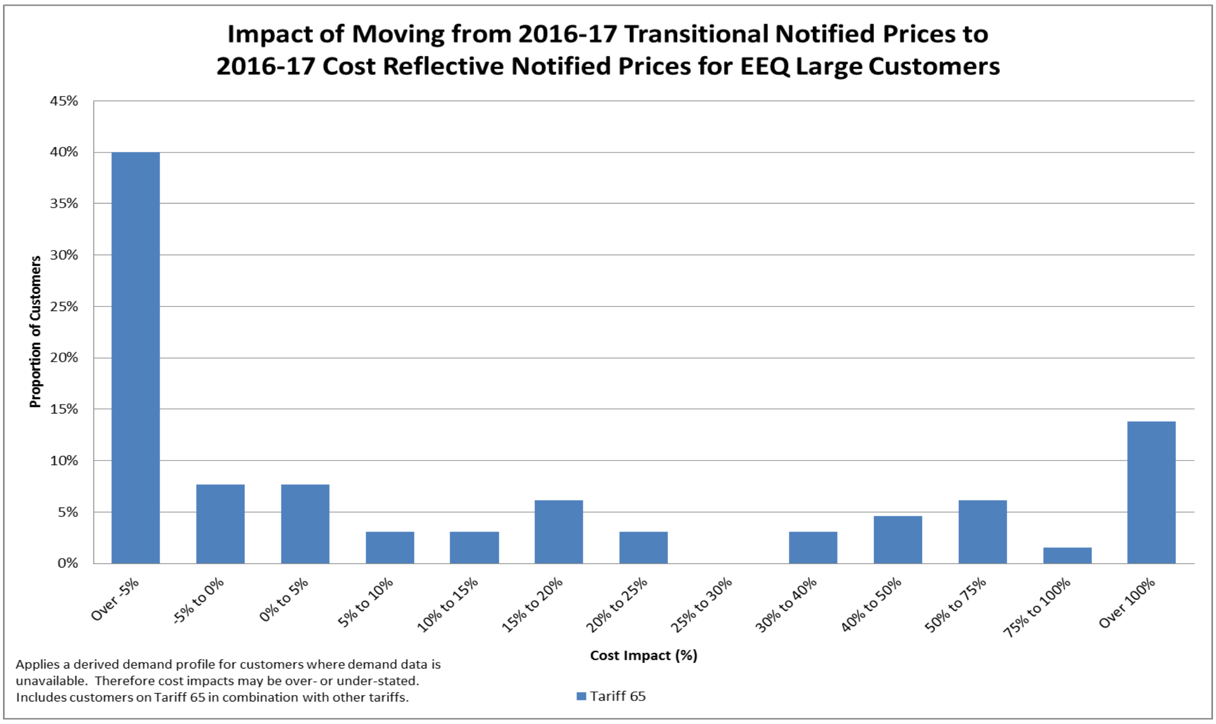
Source: Ergon Retail.

Figure 31 Change in electricity bills for small business customers on tariff 65 moving to tariff 22A



Source: Ergon Retail.

Figure 32 Change in electricity bills for large business customers on tariff 65 moving to large customer standard business tariffs

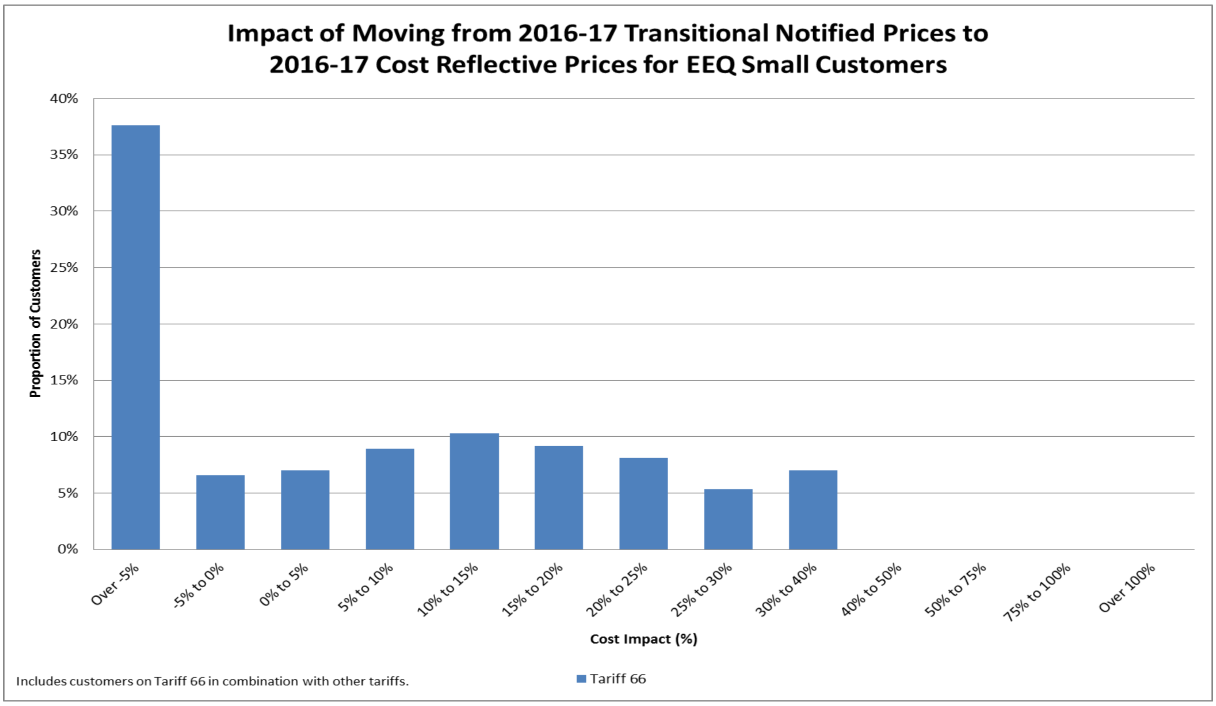


Source: Ergon Retail.

Tariff 66

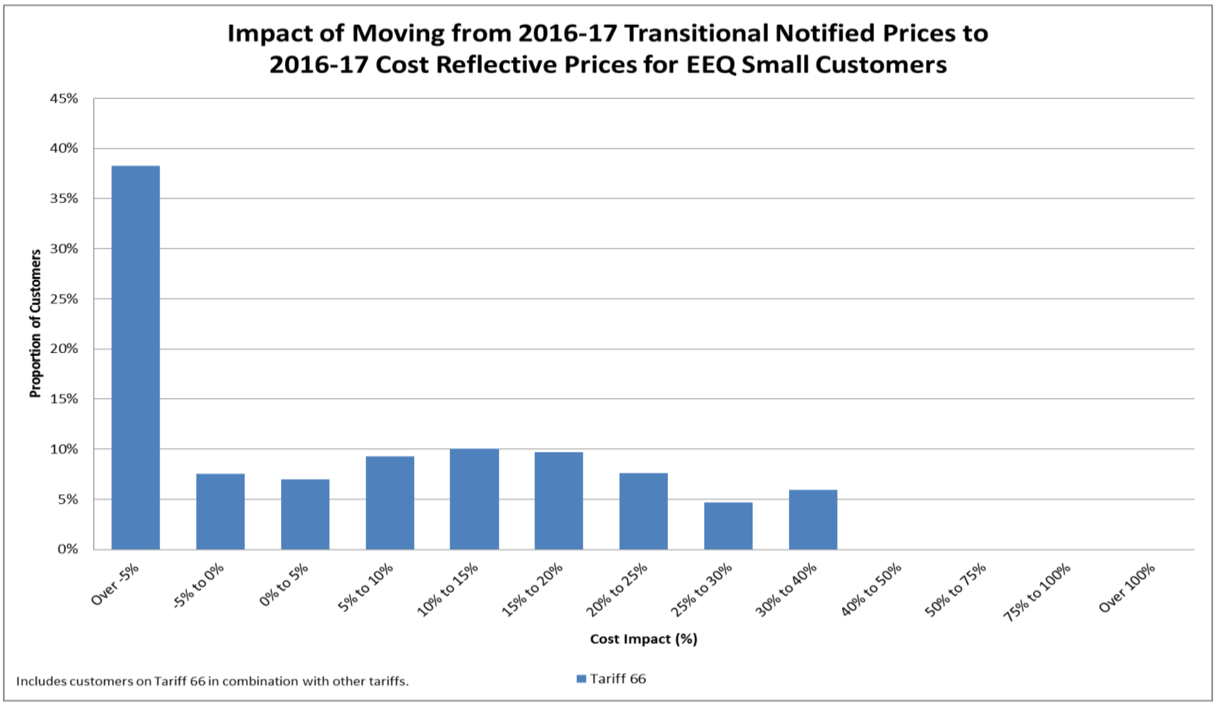
Tariff 66 is a flat-rate tariff for irrigation customers. This tariff aligns with tariffs 20 or 22A for small business customers and tariffs 44 and 45 for large business customers. Figures 33 to 34 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 33 Change in electricity bills for small business customers on tariff 66 moving to tariff 20



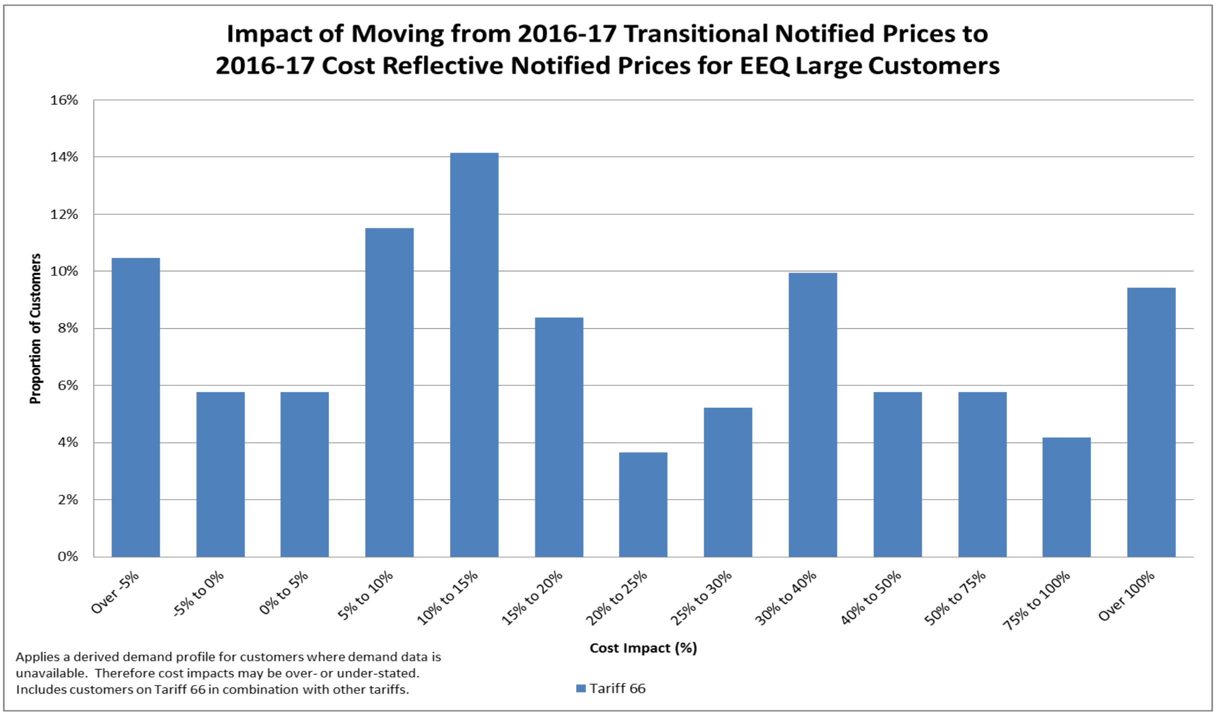
Source: Ergon Retail.

Figure 34 Change in electricity bills for small business customers on tariff 66 moving to tariff 22A



Source: Ergon Retail.

Figure 35 Change in electricity bills for large business customers on tariff 66 moving to large customer standard business tariffs



Source: Ergon Retail.

APPENDIX F: GAZETTE NOTICE

This is the draft gazette notice for 2018–19, which reflects the QCA's draft determination. Matters in part 1 of the gazette notice are supplied by the Queensland Government as they reflect government policy decisions. We understand that, while the policy intent remains the same, the government is considering making changes to the wording for the Easy Pay Rewards scheme. These changes, if any, will be considered in our final determination.

Queensland Government Gazette

RETAIL ELECTRICITY PRICES FOR STANDARD CONTRACT CUSTOMERS

Electricity Act 1994

The notified prices are the prices decided under section 90(1) of the *Electricity Act 1994* (the Electricity Act).

A retailer must charge its Standard Contract Customers, as defined in the Electricity Act, the notified prices subject to the provisions of sections 91, 91A and 91AA of the Electricity Act and section 22A, Division 12A of Part 2 of the National Energy Retail Law (Queensland) (the NERL (Qld)).

Pursuant to the Certificate of Delegation from the Minister for Natural Resources, Mines and Energy and sections 90 and 90AB of the Electricity Act, I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2018, the notified prices are the applicable prices set out in the attached Tariff Schedule.

As required by section 90AB(4) of the Electricity Act, the notified prices are exclusive of the goods and services tax ('GST') payable under the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) (the GST Act).

In addition to the applicable tariff, a retailer may charge a Standard Contract Customer an additional amount in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not that additional amount is calculated on the basis of the customer's electricity usage), but only if:

(a) the customer voluntarily participates in such program or scheme;

(b) the additional amount is payable under the program or scheme; and

(c) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

Dated this TBC day of May 2018.

Roy Green, Chair
Queensland Competition Authority

TARIFF SCHEDULE

Part 1 — Application

A) APPLICATION OF THIS SCHEDULE – GENERAL

This Tariff Schedule applies to all Standard Contract Customers in Queensland other than those in the Energex distribution area.

Definitions of customers and their types are those set out in the Electricity Act and the NERL(Qld). Unless otherwise defined, the terminology used in this Tariff Schedule is intended to be consistent with the energy laws.

B) APPLICATION OF TARIFFS

General

Distribution entities may have specific eligibility criteria in addition to retail tariff eligibility requirements set out in the Tariff Schedule, e.g. the types of loads and how they are connected to interruptible supply tariffs. Retailers will advise customers of any applicable distribution entity requirements upon tariff assignment or customer request.

Additional customer descriptions:

- *Farming* is the undertaking of agricultural or associated business activities for the primary purpose of profit. The primary use of electricity supplied under a farming tariff should be for farming.
- *Irrigation* is the undertaking of pumping water for farming. The primary use of electricity supplied under an irrigation tariff should be for irrigation.
- A *Connection Asset Customer (CAC)* is a large business customer whose required capacity generally exceeds 1500 kVA and annual energy usage generally exceeds 4GWh as classified by the distribution entity.
- An *Individually Calculated Customer (ICC)* is a large business customer whose annual energy usage generally exceeds 40GWh as classified by the distribution entity.

CAC or ICC customers can only access tariffs where specifically stated in the tariff description, or as agreed by the retailer.

MI means the unique identification number applicable to the point at which a premises is connected to a distribution entity's network. For premises connected to the National Electricity Market this is the National Metering Identifier (NMI), and for other premises is the unique identifier allocated by the distribution entity.

An *MI exclusive* tariff cannot be used in conjunction with any other tariff at that MI. All large customer continuous supply tariffs are MI exclusive tariffs unless otherwise stated.

A *primary* tariff is the tariff that reflects the principal purpose of use of electricity at the premises or the majority of the load, and is capable of existing by itself against a MI.

Small business customers can access primary residential tariffs providing the nature of all use on the tariff is consistent with the tariff requirements (refer below for *concessional application* of primary residential tariffs), and is in conjunction with a primary business tariff (Tariff 20, 21, 22, 22A, 24, 41, 62, 65 or 66) at the same MI.

Primary residential tariffs are also applicable to electricity used in separately metered common sections of residential premises consisting of more than one living unit, but cannot be used in conjunction with another primary residential tariff at the same MI.

A *secondary* tariff is any tariff that is not a primary tariff, and can be accessed only when it is in conjunction with a primary tariff at the same MI unless otherwise stated.

A *seasonal* tariff is any tariff for which charges vary depending on the month the charge applies. Seasonal tariffs can also include time-of –use based charges.

A *time-of-use* tariff is any tariff for which charges vary depending on the time of day.

A *transitional* tariff can be accessed by eligible customers for a limited period of time.

An *obsolete* tariff can only be accessed by customers who:
(a) are on the tariff at the date it becomes obsolete; and

(b) take continuous supply under it.

Transitional and obsolete tariffs will be discontinued no later than the *scheduled phase-out date*. Customers on these tariffs may opt to transfer at any time to applicable standard tariffs.

Any reference in this Tariff Schedule to a time is a reference to Eastern Standard Time.

Weekdays mean Monday to Friday including public holidays.

Summer is the months of December to February inclusive.

Peak summer window is from 4:00pm to 9:00pm on any day within months November to March.

A *daily supply charge* is a fixed amount charged to cover the costs of maintaining electricity supply to a premises, including the costs associated with the provision of equipment (excluding metering and associated services) and general administration. Retailers may use different terms for this charge, for example: Service Charge, Service Fee, Service to Property Charge etc.

A *minimum daily payment* only applies when usage charges for the billing period are less than the total of the minimum daily payment multiplied by the number of days in the billing period. Where the total minimum daily payment is charged, usage charges will not apply.

A connection charge reflects the value of the customer's dedicated connection assets and whether these assets were paid for upfront by the customer. The number of connection units allocated to an MI is as advised by the distribution entity.

Demand is the average rate of use of electricity over a 30-minute period as recorded in kilowatts (kW) on the associated metering, or as calculated in kilovolt-amperes (kVA) using data recorded on the associated metering. No adjustment to import demand is made for export to the distribution network.

Maximum demand is highest demand during the charging period of the particular tariff as identified by the tariff description. Unless otherwise stated, the maximum demand is the value on which demand charges are based.

A *demand threshold* is the demand value below which demand charges do not apply for billing purposes. Where a demand threshold applies, the chargeable demand is the greater of the maximum demand less the demand threshold, or zero.

Authorised demand is the maximum demand permitted to be imported from, or exported to the network, and is specific to each MI. The value is generally established by agreement between the customer and distribution entity.

Capacity is a demand-based measure of the network supply capability reserved for a customer. Unless otherwise stated, the capacity charge is the greater of the authorised demand, or actual maximum demand.

Reactive demand is the average rate of use of electricity over a 30-minute period as recorded in kilovolt-amperes reactive (kVAr) on the associated metering.

Permissible reactive demand for an MI is determined by applying its compliant power factor (as set out by the National Energy Rules) to its authorised demand.

Excess reactive demand (also known as excess reactive power) charges are the greater of the reactive demand occurring at the time of the maximum demand, less the permissible reactive demand, or zero.

Bus customers are those taking supply via direct connection to the distribution entity's zone substation or similar as advised by the distribution entity.

Line customers are those taking supply via direct connection to the distribution entity's high voltage electrical wires, cabling, or similar as advised by the distribution entity.

Revenue metering is metering used for billing purposes. Appropriate revenue metering must be in place for each tariff at a MI. If a change to the customer's revenue metering is required to support the applicability of a tariff to a customer, the customer may request the retailer to install the required metering at the customer's cost.

Charges for metering and associated services levied by Ergon Energy Corporation Limited are not included in notified prices. Metering charges levied by Ergon Energy Corporation Limited are regulated by the Australian Energy Regulator and will be applied in addition to the notified prices contained in this Tariff Schedule.

The *metrology procedure* is issued by the Australian Energy Market Operator as varied by the Electricity Distribution Network Code.

Interruptible supply tariffs

General:

These tariffs are applicable when electricity supply is:

(a) connected to approved apparatus (e.g. pool pump) via a socket-outlet as approved by the retailer; or

(b) permanently connected to approved apparatus (e.g. electric hot water system) as approved by the retailer (but not applicable if provision has been made to supply the apparatus under a different tariff during the supply interruption period).

The retailer will arrange the provision of load control equipment on a similar basis to provision of the required revenue metering.

Tariff 31

In addition to the general requirements above, this tariff is also applicable when electricity supply is permanently connected to approved specified parts of apparatus (e.g. hot water system booster heating unit), as approved by the retailer, but not applicable if provision has been made to supply the specified part under a different tariff during the supply interruption period except as agreed by the retailer (e.g. for a one-shot booster for a solar hot water system), in which case it must be metered under and charged at the primary tariff of the premises concerned, or if more than one primary tariff exists, the tariff applicable to general power usage at the premises.

Tariff 33

In addition to the general requirements above, this tariff is also applicable as a primary tariff at the absolute discretion of the retailer.

This tariff shall not apply in conjunction with Tariff 24.

Transitional and obsolete tariffs

Tariff 20 (large)

This tariff cannot be accessed by small customers.

Tariff 21

This tariff shall not apply in conjunction with Tariff 20, 22, 22A, 24 or 62.

Tariff 37

This tariff is applicable when electricity supply is permanently connected to approved apparatus (e.g. electric storage hot water system, apparatus for the production of steam) as approved by the retailer.

Tariff 47

Supply under this tariff will be at a standard high voltage, the level of which shall be prescribed by the distribution entity. Credits for high voltage supply are not applicable to this tariff.

Tariff 62

This tariff shall not apply in conjunction with Tariff 20, 21, 22, 22A or 24.

Tariff 65

The *daily pricing period* is a fixed 12-hour period as agreed between the retailer and the customer from the range 7.00am to 7.00pm; 7.30am to 7.30pm; or 8.00am to 8.00pm Monday to Sunday inclusive.

No alteration to the agreed daily pricing period is permitted until a period of twelve months has elapsed from the previous selection.

Tariff 66

The annual fixed charge is determined by the connected motor capacity used for irrigation pumping.

Any customer taking supply under this tariff who requests a temporary disconnection will not be reconnected unless an amount equivalent to the fixed charge that would have otherwise applied corresponding to the period of disconnection, has been paid.

Unmetered supply tariffs

Tariff 71

Street lighting customers as defined in Queensland legislative instruments, are State or local government agencies for street lighting loads.

Street lights are deemed to illuminate the following types of roads:

- *Local government* controlled roads comprising land that is:
  - (a) dedicated to public use as a road; or
  - (b) developed for (or has as one of its main uses) the driving or riding of motor vehicles and is open to, or used by, the public; or

(c) a footpath or bicycle path; or

(d) a bridge, culvert, ford, tunnel or viaduct,

and excludes State-controlled roads and public thoroughfare easements; and

- *State-controlled roads* declared as such under the *Transport Infrastructure Act 1994* (Qld).

All usage will be determined in accordance with the metrology procedure.

Tariff 91

It is available only to customers with small loads other than street lights as approved by the retailer, and applies where:

(a) the load pattern is predictable;

(b) for the purposes of settlements, the load pattern (including load and on/off time) can be reasonably calculated by a relevant method set out in the metrology procedure; and

(c) it would not be cost effective to meter the connection point taking into account:

(i) the small magnitude of the load;

(ii) the connection arrangements; and

(iii) the geographical and physical location.

Charges are based on usage determined by the retailer.

Charges for installation, maintenance and removal of supply to an unmetered installation may apply in addition to the charge for electricity supplied. These charges are unregulated.

Tariff changes

Customers previously supplied under tariffs which have been discontinued or redesignated (whether by number, letter or name) will be supplied under other tariffs appropriate to their installations.

Customers on seasonal and/or transitional time-of-use tariffs cannot change to another tariff less than one year from the application of the tariff to the customer's account without the retailer's agreement unless expressly allowed or permitted by energy law.

Prorating of charges on bills

Where appropriate, charges on bills will be calculated on a pro rata basis having regard to the number of days in the billing cycle that supply was connected as expressly allowed or permitted by energy law. Retailers can advise customers of which charges on their bills are subject to prorating, and the methodology used.

Supply voltage

Tariffs in this Schedule can only be accessed by customers taking supply at *low voltage* as set out in the *Electricity Regulation 2006* unless it is a designated high voltage tariff, or otherwise agreed with the retailer.

Where supply is given and metered at high voltage and the tariff applied is not a designated high voltage tariff, after billing the energy and demand components of the tariff a credit will be allowed of:

- 5 percent of the calculated tariff charge where supply is given at voltages of 11kV to 33kV; or
- 8 percent of the calculated tariff charge where supply is given at voltages of 66kV and above,

provided that the calculated tariff charge after application of the credit is not less than the Minimum Payment or other minimum charge calculated by applying the provisions of the applied tariff.

Card-operated meter customers

If a customer is an excluded customer (as defined in section 23 of the Electricity Act), the distribution entity may at its absolute discretion agree with the relevant local government authority on behalf of the customer, and the customer's retailer, that the electricity used by the customer is to be measured and charged by means of a card-operated meter.

If, immediately prior to 1 July 2007, electricity being used by a customer at premises is being measured and charged by means of a card-operated meter, the electricity used at the premises may continue to be measured or charged by means of a card-operated meter.

Residential customers with card-operated meters can access Tariff 11 as their primary tariff, and Tariffs 31 and 33 as secondary tariffs.

Small business customers with card-operated meters can access Tariff 20 as their primary tariff.

Charges will be those as set out in Part 2 for the particular tariff.

Easy Pay Rewards

From 1 December 2017, Ergon Energy Queensland Pty Ltd may allow

Standard Contract Customers an annual reward of:

- for an eligible residential customer— $75; or
- for an eligible non-residential small customer—$120,

(each, an *annual reward* amount).

To be an eligible customer, a residential or a non-residential small customer must 'opt-in' by agreeing to each of the following (eligibility requirements):

- to receive bills electronically (i.e. no paper bills);
- to pay bills either weekly, fortnightly or monthly (as agreed) by direct debit or CentrePay by the due date; and
- to accept bill smoothing.

An eligible customer 'opts-out' if, at any time:

- the customer notifies Ergon Energy Queensland Pty Ltd the customer wants to opt-out; or
- the customer stops agreeing to 1 or more of the eligibility requirements.

The reward scheme will operate as follows:

a) Ergon Energy Queensland Pty Ltd must allow an eligible customer who has opted in under a Standard Contract to defer payment of the annual reward amount as to that Standard Contract.

b) The deferred annual reward amount for a Year becomes payable if, within 6 months of opting in, the eligible customer:

    (i) opts out; or

    (ii) does not maintain payment of bills by direct debit or CentrePay (as relevant).

c) For an eligible customer, any deferred annual reward amount for a Year ceases to be payable (and not just deferred) on the first anniversary of the commencement of that Year.

d) An eligible customer, having opted out, may subsequently opt in under the same Standard Contract, provided that:
   (i) any deferred annual reward amount payable for that Standard Contract under paragraph (b) has been paid; and
   (ii) if no amount is payable under paragraph (b), the customer has not received a deferred annual reward amount within the 12 months before the day the customer opts back into the scheme
e) The 'Year' for the purposes of the annual reward for an eligible customer commences on the day the customer pays the bill issued after:
   (i) The customer opts-in;
   (ii) A meter reading is taken with respect to that Standard Contract; and
   (iii) A bill is issued with respect to that Standard Contract.
f) Key Easy Pay Reward dates:
   Commencement of Easy Pay Reward:
   1 December 2017
   Closure of Easy Pay Reward (final bill credits to be applied by this date): **31 December 2019**

Other retail fees and charges

A retailer may charge its Standard Contract Customers the following:

(a) if, at a customer's request, the retailer provides historical billing data which is more than two years old:
   – a maximum of **$30**

(b) retailer's administration fee for a dishonoured payment:
   – a maximum of **$15**

(c) financial institution fee for a dishonoured payment:
   – a maximum of **the fee incurred by the retailer**

Concessional application

Tariffs 11, Tariff 12A and Tariff 14 are also available to customers where they satisfy the additional criteria set out in any one of **1**, **2** or **3**, below:

1. Separately metered installations where all electricity used is in connection with the provision of a Meals-on-Wheels service, or for the preparation and serving of meals to the needy and for no other purpose.

2. Residential institutions:

(a) where the total installation, or that part supplied and separately metered, must be domestic residential (i.e. it must include the electricity usage of the cooking, eating, sleeping and bathing areas which are associated with the residential usage). Medical facilities, e.g. an infirmary, which are part of the complex may be included; and

(b) that are:
   (i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and
   (ii) a non-profit organisation that:
      A. imposes no scheduled charge on the residents for the services or accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or
      B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged Care Act 1997* or the *National Health Act 1953*.

3. Organisations providing support and crisis accommodation which:

(a) meet the eligibility criteria of the Specialist Homelessness Services administered by the State Department of Housing and Public Works; and

(b) are a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible.

Part 2—Standard tariffs

These tariffs are applicable subject to the matters set out in part 1.

Small customer tariffs

Tariff	Description	Charge type	Rate	Unit
11	Residential flat-rate primary tariff	Usage	24.991	c/kWh
		Daily supply charge	88.770	c
12A	Residential seasonal time-of-use primary tariff	Summer usage – Peak (3pm–9:30pm)	62.426	c/kWh
		Summer usage – All other times	21.234	c/kWh
		Usage – All other times	21.234	c/kWh
		Daily supply charge	76.621	c
14	Residential seasonal time-of-use monthly demand primary tariff. Daily demand is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm for the Peak period (Summer) and the Off-peak period (all other times). Peak chargeable demand is the average of the four highest peak daily demands in the month. Off-peak chargeable demand is the greater of the average of the four highest off-peak daily demands in the month, or 3kW.	Chargeable demand – Peak	62.790	$/kW
		Chargeable Demand – Off peak	9.243	$/kW
		Usage	17.322	c/kWh
		Daily supply charge	45.771	c
15	Top up charge applies to any consumption that exceeds the peak summer window consumption cap. Once exceeded, the cap is extended for the month, equal to the new increased peak consumption value and is then reset to the original cap at the start of the next peak month. The consumption cap is determined by the band that the customer has chosen where:	Top up charge	4.206	$/kWh/month
		Usage	18.562	c/kWh
	-Band 1 has a 0 kWh cap during the peak summer window	Fixed charge - band 1	37.194	$/month
	-Band 2 has a 5 kWh cap during the peak summer window	Fixed charge - band 2	44.355	$/month
	-Band 3 has a 10 kWh cap during the peak summer window	Fixed charge - band 3	51.516	$/month
	-Band 4 has a 15 kWh cap during the peak summer window	Fixed charge - band 4	58.677	$/month
	-Band 5 has a 20 kWh cap during the peak window	Fixed charge - band 5	65.838	$/month
20	Small business flat-rate primary tariff.	Usage	26.124	c/kWh
		Daily supply charge	122.890	c

Tariff	Description	Charge type	Rate	Unit
22A	Small business seasonal time-of-use primary tariff.	Summer usage – Peak (10am–8pm)	52.529	c/kWh
		Summer usage – All other times	22.678	c/kWh
		Usage – All other times	22.678	c/kWh
		Daily supply charge	122.890	c
24	Small business seasonal time-of-use monthly demand primary tariff. Daily demand is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm for the Peak period (Summer) and the Off-peak period (all other times). Peak chargeable demand is the average of the four highest peak daily demands in the month. Off-peak chargeable demand is the greater of the average of the four highest off-peak daily demands in the month, or 3kW.	Chargeable demand – Peak	90.072	$/kW
		Chargeable Demand – Off peak	9.277	$/kW
		Usage	18.488	c/kWh
		Daily supply charge	62.842	c
31	Small customer flat-rate secondary tariff with interruptible supply. Supply will be available for a minimum of 8 hours per day, but times when supply is available is subject to variation at the absolute discretion of the distribution entity. In general, this supply will be between the hours of 10.00 pm and 7.00 am.	Usage	16.871	c/kWh
33	Small customer flat-rate secondary tariff with interruptible supply. Supply will be available for a minimum of 18 hours per day, but times when supply is available is subject to variation at the absolute discretion of the distribution entity.	Usage	20.535	c/kWh
41	Small business monthly demand primary tariff.	Demand	23.744	$/kW
		Usage	15.791	c/kWh
		Daily supply charge	528.715	c

Large customer tariffs

Tariff	Description	Charge type		Unit
44	Large business monthly demand primary tariff Demand threshold 30 kW.	Chargeable demand	36.674	$/kW
		Usage	14.608	c/kWh
		Daily supply charge	4611.472	c

Tariff	Description	Charge type	Rate	Unit
45	Large business monthly demand primary tariff Demand threshold 120 kW.	Chargeable demand	27.767	$/kW
		Usage	14.608	c/kWh
		Daily supply charge	15515.432	c
46	Large business monthly demand primary tariff Demand threshold 400 kW.	Chargeable demand	22.523	$/kW
		Usage	14.583	c/kWh
		Daily supply charge	40157.298	c
50	Large business seasonal time-of-use monthly demand primary tariff. Peak is Summer, being 10:00am to 8:00pm on Summer weekdays for determining chargeable demand, and all day each day for usage. Off-peak is all times in non-summer months for determining chargeable demand and usage. Peak demand threshold 20 kW. Off peak demand threshold 40 kW.	Peak chargeable demand	65.230	$/kW
		Peak usage	14.251	c/kWh
		Off-peak chargeable demand	11.727	$/kW
		Off-peak usage	16.757	c/kWh
		Daily supply charge	3731.606	c
51A	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied at 66kV.	Demand	2.756	$/kVA
		Capacity	4.652	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage	13.813	c/kWh
		Daily connection charge	10.105	$/unit
		Daily supply charge	25402.872	c
51B	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied at 33kV.	Demand	2.756	$/kVA
		Capacity	5.561	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage	13.813	c/kWh
		Daily connection charge	10.105	$/unit
		Daily supply charge	18373.122	c

Tariff	Description	Charge type	Rate	Unit
51C	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV bus.	Demand	3.417	$/kVA
		Capacity	6.396	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage	13.817	c/kWh
		Daily connection charge	10.105	$/unit
		Daily supply charge	16859.022	c
51D	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV line.	Demand	6.771	$/kVA
		Capacity	12.459	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage	13.833	c/kWh
		Daily connection charge	10.105	$/unit
		Daily supply charge	15993.822	c
52A	Large business high-voltage seasonal time-of-use monthly demand primary tariffs only for customers classified as CAC and supplied at 33 or 66kV. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	12.248	$/kVA
		Chargeable capacity	6.787	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage – Summer	13.378	c/kWh
		Usage – All other times	13.779	c/kWh
		Daily connection charge	10.105	$/unit
		Daily supply charge	12424.872	c

Tariff	Description	Charge type	Rate	Unit
52B	Large business high-voltage seasonal time-of-use monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV bus. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	45.014	$/kVA
		Chargeable capacity	4.782	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage – Summer	13.383	c/kWh
		Usage – All other times	13.783	c/kWh
		Daily connection charge	10.105	$/unit
		Daily supply charge	12424.872	c
52C	Large business high-voltage seasonal time-of-use monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV line. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	80.540	$/kVA
		Chargeable capacity	8.791	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage – Summer	13.399	c/kWh
		Usage – All other times	13.799	c/kWh
		Daily connection charge	10.105	$/unit
		Daily supply charge	12424.872	c
53	Large business high-voltage primary tariff only for customers classified as ICC.	Demand	6.771	$/kVA
		Capacity	12.459	$/kVA
		Excess reactive demand	4.454	$/kVAr
		Usage	13.833	c/kWh
		Daily supply charge	15993.822	c

Part 3—Transitional and obsolete tariffs.

These tariffs are applicable subject to the matters set out in part 1.

Tariff	Description	Charge type	*Rate*	Unit
20 (large)	Transitional large business flat-rate primary tariff. Scheduled phase-out date: 1 July 2020	Usage	37.595	c/kWh
		Daily supply charge	76.858	c

Tariff	Description	Charge type	Rate	Unit
21	Transitional business declining-block primary tariff. Scheduled phase-out date: 1 July 2020	Usage – first 100 kWh/month	49.357	c/kWh
		Usage – next 9,900 kWh/month	46.374	c/kWh
		Usage – all remaining usage	35.303	c/kWh
		Minimum daily payment	72.631	c
22 (small and large)	Transitional business time-of-use primary tariff. Scheduled phase-out date: 1 July 2020	Usage – 7am to 9pm weekdays	49.820	c/kWh
		Usage – all other times	17.543	c/kWh
		Daily supply charge	184.717	c
37	Obsolete business time-of-use primary tariff. Scheduled phase-out date: 1 July 2020	Usage – 4:30pm–10:30pm	54.544	c/kWh
		Usage – all other times	21.807	c/kWh
		Minimum daily payment	30.623	c
47	Obsolete large business high voltage monthly demand primary tariff. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022	Chargeable demand	27.864	$/kW
		Usage	12.446	c/kWh
		Daily supply charge	44689.726	c
48	Obsolete large business high voltage monthly demand primary tariff only for customers classified as CAC or ICC. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022	Chargeable demand	28.822	$/kW
		Usage	12.874	c/kWh
		Daily supply charge	46712.140	c
62	Transitional farming business time-of-use declining-block primary tariff. Scheduled phase-out date: 1 July 2020	Usage – 7am to 9pm weekdays first 10,000kWh per month	46.516	c/kWh
		Usage – 7am to 9pm weekdays all remaining usage	39.336	c/kWh
		Usage – all other times	16.448	c/kWh
		Daily supply charge	78.451	c

Tariff	Description	Charge type	Rate	Unit
65	Transitional irrigation business time-of-use primary tariff. Scheduled phase-out date: 1 July 2020	Usage – Peak (daily pricing period)	36.894	c/kWh
		Usage – all other times	20.321	c/kWh
		Daily supply charge	78.003	c
66	Transitional irrigation business fixed annual dual-rate demand primary tariff. Scheduled phase-out date: 1 July 2020	Fixed charge (annual) – first 7.5kW	37.503	$/kW
		Fixed charge (annual) – remaining kW	112.759	$/kW
		Usage	19.338	c/kWh
		Daily supply charge	171.915	c

Part 4—Unmetered supply tariffs

These tariffs are applicable subject to the matters set out in part 1.

Tariff	Description	Charge type	*78.003*	Unit
71	Business flat-rate primary tariff for street lighting.	Usage	31.189	c/kWh
		Daily supply charge	0.420	c/lamp
91	Business flat-rate primary tariff.	Usage	23.953	c/kWh

Part 5—Metering charges

Type 1, 2, 3, 4 (advanced digital) meters—large business

Description	Charge type	Rate	Unit
Standard asset customer.	Daily metering charge	141.078	c
Connection asset customer.	Daily metering charge	328.542	c
Individually calculated customer.	Daily metering charge	506.502	c

Tariff	Description	Charge type	Rate	Unit

Type 4, 4A (advanced digital) meters—residential and small business.

Description	Meter	Rate	Unit
Primary flat rate tariff daily metering charge (Tariffs 11 and 20—per tariff)	Type 4	27.590	c
	Type 4A	43.612	c
Primary time-of-use tariff daily metering charge (Tariffs 12A, 22A, 22 (small and large), 37, 62, 65, 66—per tariff)	Type 4	27.590	c
	Type 4A	43.612	c
Primary demand tariff daily metering charge (Tariffs 14, 15, 24—per tariff)	Type 4	27.590	c
	Type 4A	43.612	c
Primary tariff with controlled load daily metering charge—per tariff.	Type 4	30.749	c
	Type 4A	46.771	c

Type 6 (accumulation) meters—residential and small business.

Description	Charge Type	Rate	Unit
Primary tariff daily metering charge (per tariff).	Capital	7.167	c
Tariffs 11, 12A, 20, 22A, 22 (small and large), 37, 62, 65, 66	Non-capital	2.314	c
	Total	9.481	c
Controlled load daily metering charge (per tariff).	Capital	2.150	c
Tariffs 31, 33	Non-capital	0.694	c
	Total	2.844	c

End of Tariff Schedule

APPENDIX G: ASSUMPTIONS AND DATA USED TO DETERMINE CUSTOMER IMPACTS

Typical customer figures are based on the annual consumption of the median customer on each tariff in regional Queensland. Consistent with previous price determinations, Ergon Distribution provided the forecast usage for tariffs 12A and 22A[184] while Ergon Retail provided actual usage data for the remaining tariffs.

The median customer is the middle customer in terms of consumption out of all customers on each tariff. As such, approximately half of all customers will use less electricity than the typical figure, and half will use more. Stakeholders requested the QCA provide a range of bill impacts for residential customers. For this price determination, the QCA has provided tariff 11 bill impacts for the 25th and 75th percentile customers. One quarter of customers will use less electricity than the 25th percentile customer, while three-quarters of customers will use less electricity than the 75th percentile customer.

In submissions for previous determinations, stakeholders noted that the typical customer figures provided by Ergon Retail appear lower than those on the AER's Energy Made Easy website. The reason for the discrepancy is that the Energy Made Easy website uses average consumption figures based on a survey of 4,000 customers across Australia in 2014, while Ergon Retail uses actual consumption figures from their customer base of over 700,000 electricity customers in regional Queensland.

Table 38 Usage data used to determine customer impacts

Retail tariff	*Usage (kWh per year)*	*Peak usage (%)*	*Off-peak usage (%)*	*Demand (kW per month)*	*Demand threshold (kW per month)*
T11 (only)—25th percentile	2,554				
T11 (only)—median	4,184				
T11 (only)—75th percentile	6,547				
T11 (with T31)—median	4,369				
T31—median	1,743				
T11 (with T33)—median	4,054				
T33—median	1,620				
T20—median	6,835				
T12A—median[a]	4,159	11	89		
T22A—median[a]	7,625	10.1	89.9		
T44—median	235,977			54	30
T45–median	868,631			204	120
T46–median	2,254,639			521	400

a *At the time of the draft determination, Ergon Distribution's best forecasts were forecast figures provided to the QCA as part of the 2017–2018 pricing determination.*

[184] Forecast data were provided, as actual usage data were considered unreliable due to the very small number of customers on these tariffs.

APPENDIX H: SUMMARY OF CONCESSIONAL ARRANGEMENTS FOR ELECTRICITY IN QUEENSLAND

Concession Name	***Eligibility Criteria***	***Annual Amount***
Electricity Rebate	Customers with a Pensioner Concession Card issued by either Centrelink or Department of Veterans' Affairs, a Department of Veterans' Affairs Gold Card (and recipient of the War Widow Pension or special rate TPI Pension), a Queensland Government Seniors Card, a Commonwealth Health Care Card, and customers who are asylum seekers. Customers in residential home parks and multi-unit residential premises are paid $0.8489 (exclusive of GST) per day.	$340.85
Electricity asset ownership dividend	To provide continued electricity bill relief for all Queensland households, $200 million from the dividends of government owned corporations will be delivered as a $50 per year ($100 over 2 years) rebate for households over the next 2 years.	$50.00
Energy efficient appliance rebate	To help Queensland households improve their energy efficiency, $20 million has been committed under the Affordable Energy Plan for rebates on approved energy efficient appliances.	$200 for a 4 star energy rated washing machine. $250 for a 4 star energy rated refrigerator. $300 for a 4 star energy rated air conditioner.
No interest loans and rebates for rooftop solar and battery systems	No interest loans for rooftop solar and battery systems are available from March 2018. Rebate of $1,300–$2,000 for battery systems.	
Home Energy Emergency Assistance Scheme	Customers must either hold a current, eligible concession card, or have a base income of no more than the Commonwealth Government's maximum income rate for part-age pensioners, or be on their retailer's hardship program or payment plan.	Up to $720 once every two years.
Electricity Life Support Concession Scheme	Customers must be medically assessed in accordance with the eligibility criteria determined by Queensland Health. In addition, oxygen concentrators must be provided rent-free by Queensland Health to persons who hold an eligible concession card and meet the eligibility criteria of the Medical Aids Subsidy Scheme. Kidney dialysis machines must be provided rent-free by Queensland Health to persons based on clinical needs and supplied through Queensland hospitals.	$694.18 per year for each oxygen concentrator. $464.88 for each kidney dialysis machine.
Medical Cooling and Heating Electricity Concession Scheme	Queensland residents with a qualifying medical condition requiring cooling or heating to prevent the decline of symptoms, who reside at their principal place of residence which has an air-conditioning unit.	$340.85
Drought relief from Electricity Charges Scheme	Certain farmers who use electricity for irrigation pumping during periods of very low or no water availability.	The Drought Relief from Electricity Charges Scheme (DRECS) provides relief from supply charges on electricity accounts that are used to pump water for farm or irrigation purposes.

For more information see https://www.qld.gov.au/community/cost-of-living-support/energy-concessions.

APPENDIX I: BUILD-UP OF NOTIFIED PRICES

Table 39 Regulated retail tariffs and prices for residential customers (GST exclusive)

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage (c/kWh)***	***Off-peak/Flat usage (c/kWh)***	***Peak demand ($/kW/mth)***	***Off-peak/Flat demand ($/kW/mth)***
Tariff 11—Residential (flat-rate)	Network	47.900		8.457		
	Energy			12.933		
	Fixed retail	36.643				
	Variable retail			2.411		
	Standing offer adjustment	4.227		1.190		
	SRES cost pass-through					
	Total	**88.770**		**24.991**		
Tariff 12A—Residential (seasonal time-of-use)	Network	36.329	40.498	5.241		
	Energy		12.933	12.933		
	Fixed retail	36.643				
	Variable retail		6.022	2.048		
	Standing offer adjustment	3.649	2.973	1.011		
	SRES cost pass-through					
	Total	**76.621**	**62.426**	**21.234**		
Tariff 14—Residential (seasonal time-of-use demand)	Network	6.948		1.893	53.743	7.911
	Energy			12.933		
	Fixed retail	36.643				
	Variable retail			1.671	6.057	0.892
	Standing offer adjustment	2.180		0.825	2.990	0.440
	SRES cost pass-through					
	Total	**45.771**		**17.322**	**62.790**	**9.243**
Tariff 31—Night rate super economy	Network			5.741		
	Energy			8.699		
	Fixed retail					
	Variable retail			1.627		
	Standing offer adjustment			0.803		

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/Flat usage*	*Peak demand ($/kW/mth)*	*Off-peak/Flat demand*
	SRES cost pass-through					
	Total			**16.871**		
Tariff 33—Controlled supply economy	Network			6.991		
	Energy			10.585		
	Fixed retail					
	Variable retail			1.981		
	Standing offer adjustment			0.978		
	SRES cost pass-through					
	Total			**20.535**		

a *Charged per metering point.*

Note: Totals may not add due to rounding.

Table 40 Regulated retail tariffs and prices for residential customers (GST exclusive)

Retail Tariff	*Tariff Component*	*Fixed Band 1 ($/mth)*	*Fixed Band 2 ($/mth)*	*Fixed Band 3 ($/mth)*	*Fixed Band 4 ($/mth)*	*Fixed Band 5 ($/mth)*	*Usage (c/kWh)*	*Top up Charge ($/kWh/mth)*
Tariff 15 - Residential	Network	24.270	31.090	37.910	44.730	51.550	2.954	3.600
	Energy						12.933	
	Fixed retail	11.153	11.153	11.153	11.153	11.153		
	Variable retail						1.790	0.406
	Standing offer adjustment	1.771	2.112	2.453	2.794	3.135	0.884	0.200
	SRES cost pass-through							
	Total	**37.194**	**44.355**	**51.516**	**58.677**	**65.838**	**18.562**	**4.206**

Note: Totals may not add due to rounding.

Table 41 Regulated retail tariffs and prices for small business and unmetered supply customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/Flat usage (c/kWh)*	*Peak demand ($/kW/mth)*	*Off-peak/Flat demand ($/kW/mth)*
Tariff 20–Business (flat-rate)	Network	65.100		9.123		
	Energy			12.933		
	Fixed retail	51.938				
	Variable retail			2.823		
	Standing offer adjustment	5.852		1.244		
	SRES cost pass-through					
	Total	**122.890**		**26.124**		
Tariff 22A–Business (seasonal time-of-use)	Network	65.100	31.417	6.214		
	Energy		12.933	12.933		
	Fixed retail	51.938				
	Variable retail		5.677	2.451		
	Standing offer adjustment	5.852	2.501	1.080		
	SRES cost pass-through					
	Total	**122.890**	**52.529**	**22.678**		
Tariff 24–Business (seasonal time-of-use demand)	Network	7.911		2.676	76.049	7.833
	Energy			12.933		
	Fixed retail	51.938				
	Variable retail			1.998	9.734	1.003
	Standing offer adjustment	2.992		0.880	4.289	0.442
	SRES cost pass-through					
	Total	**62.842**		**18.488**	**90.072**	**9.277**
Tariff 41–Business low voltage (demand)	Network	451.600		0.399		20.047
	Energy			12.933		
	Fixed retail	51.938				
	Variable retail			1.707		2.566
	Standing offer adjustment	25.177		0.752		1.131
	SRES cost pass-through					

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage (c/kWh)***	***Off-peak/Flat***	***Peak demand ($/kW/mth)***	***Off-peak/Flat demand***
	Total	**528.715**		**15.791**		**23.744**
Tariff 91–Unmetered supply	Network			7.290		
	Energy			12.933		
	Fixed retail					
	Variable retail			2.589		
	Standing offer adjustment			1.141		
	SRES cost pass-through					
	Total			**23.953**		

a. *Charged per metering point.*

Note: Totals may not add due to rounding

Table 42 Regulated retail tariffs and prices for large business and street lighting customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/Flat usage (c/kWh)*	*Peak demand ($/kW/mth)*	*Off-peak/Flat demand ($/kW/mth)*
Tariff 44—Business over 100 MWh/yr—Small (demand)	Network	3878.900		1.361		32.937
	Energy			11.758		
	Fixed retail	512.978				
	Variable retail			0.793		1.991
	Headroom	219.594		0.696		1.746
	SRES cost pass-through					
	Total	**4611.472**		**14.608**		**36.674**
Tariff 45—Business over 100 MWh/yr—Medium (demand)	Network	13612.800		1.361		24.937
	Energy			11.758		
	Fixed retail	1163.802				
	Variable retail			0.793		1.507
	Headroom	738.830		0.696		1.322
	SRES cost pass-through					
	Total	**15515.432**		**14.608**		**27.767**
Tariff 46—Business over 100 MWh/yr—Large (demand)	Network	35502.400		1.339		20.228
	Energy			11.758		
	Fixed retail	2742.646				
	Variable retail			0.792		1.223
	Headroom	1912.252		0.694		1.073
	SRES cost pass-through					
	Total	**40157.298**		**14.583**		**22.523**
Tariff 50—Business over 100 MWh/yr (seasonal time-of-use demand)	Network	3077.900	1.041	3.291	58.583	10.532
	Energy		11.758	11.758		
	Fixed retail	476.010				
	Variable retail		0.774	0.910	3.541	0.637
	Headroom	177.696	0.679	0.798	3.106	0.558
	SRES cost pass-through					
	Total	**3731.606**	**14.251**	**16.757**	**65.230**	**11.727**
Tariff 71—	Network	0.400		16.253		

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage***	***Off-peak/Flat***	***Peak demand ($/kW/mth)***	***Off-peak/Flat demand***
Street lighting	Energy			11.758		
	Fixed retail					
	Variable retail			1.693		
	Headroom	0.020		1.485		
	SRES cost pass-through					
	Total	**0.420**		**31.189**		

a. *Charged per metering point.*

Note: Totals may not add due to rounding.