Queensland Competition Authority

Final determination

Regulated retail electricity prices for 2020–21

Regional Queensland

June 2020

Level 27, 145 Ann Street, Brisbane Q 4000
GPO Box 2257, Brisbane Q 4001
Tel (07) 3222 0555
www.qca.org.au

We wish to acknowledge the contribution of the electricity team to this report.

Contents

1 ABOUT THIS REVIEW

1.1 What have we been asked to do?

We received a delegation from the Minister[1] to set regulated retail electricity prices (notified prices) to apply in regional Queensland[2] in 2020–21. We are delegated this task in accordance with the Electricity Act 1994 (Electricity Act).[3]

1.2 Scope of our review

Since we set prices under a delegation from the Minister, we are required to have regard to the relevant legal framework. The framework is contained in the Electricity Act and sets out factors[4] we must have regard to when making a price determination. These are:

- the actual costs of making, producing or supplying the goods or services
- the effect of the price determination on competition in the Queensland retail electricity market
- any matter we are required by delegation to consider.

We may also have regard to any other matter we consider relevant.[5]

Matters we must consider under the delegation

The Minister's delegation includes a terms of reference, which contains particular details and matters relevant to our price determination:

- the period—the price determination is to apply from 1 July 2020 to 30 June 2021
- the timeframes—we must publish our:
  - draft determination by no later than March 2020
  - final price determination and have the retail prices gazetted by no later than 26 June 2020
- particular policies or principles—we are to set notified prices having regard to, among other matters, the Queensland Government's Uniform Tariff Policy (UTP)
- pricing methodology—we are to set notified prices having regard to the network plus retail (N+R) cost build-up methodology
- consultation—we are required to consult at various stages before making the final price determination and consider holding stakeholder workshops on identified key issues.

A copy of the delegation, including the terms of reference, is provided in Appendix A.

[1] The Minister for Natural Resources, Mines and Energy in Queensland.
[2] Outside the Energex area.
[3] Section 90AA of the Electricity Act.
[4] Section 90(5)(a) of the Electricity Act.
[5] Section 90(5)(b) of the Electricity Act.

1.3 Our review process and consultation

Interim consultation paper

On 11 December 2019, we released an interim consultation paper and invited stakeholders to comment on key issues relevant to this year's price determination. In response, we received 10 stakeholder submissions.[6]

Draft determination

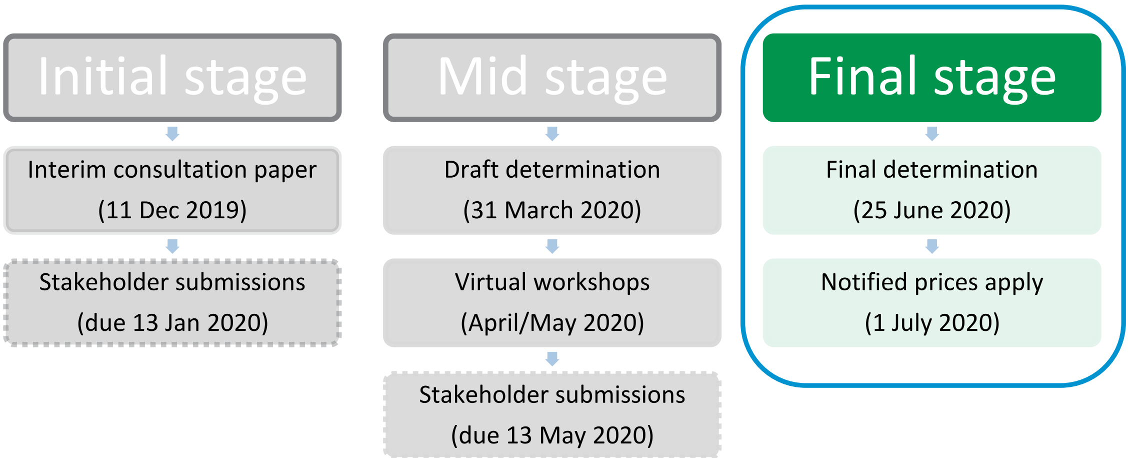
On 31 March 2020, we released a draft price determination and invited stakeholders to comment, including on the draft notified prices. In response, we received 13 stakeholder submissions. We also held virtual stakeholder workshops prior to the submission due date to assist stakeholders in preparing submissions.[7]

Final determination

This final determination contains notified prices, presented as bundled prices appropriate to the retail tariff structure (except for the site-specific tariffs).[8]

In making this final determination, we had regard to the relevant factors in the Electricity Act, matters in the delegation, comments from stakeholders and our own analysis.

This is the final stage of our review process. The notified prices set out in this final determination will apply from 1 July 2020.



[6] Public submissions are available on our website at https://www.qca.org.au/project/customers/electricity-prices/regulated-electricity-prices-for-regional-qld-2020-21/.
[7] Public submissions and the workshop information pack is available on our website (using link in footnote 6 above).
[8] As required in section 8 of the delegation terms of reference (set out in Appendix A).

1.4 Structure of this paper

This report is structured as follows:

- Indicative bill impacts of notified prices (chapter 2)
- Overarching framework—policy and pricing matters (chapter 3)
- Cost build-up components—individual cost elements (chapter 4)
  - Network component (section 4.1)
  - Retail component (section 4.2)
    - Energy costs (section 4.2.1)
    - Retail costs (section 4.2.2)
- Other costs and pricing issues (chapter 5)
- Final notified prices (chapter 6).

1.5 Supporting documents

An information booklet accompanies this report, providing an 'at a glance' overview of our price setting process and final notified prices (as contained in this report). It aims to assist stakeholders to become quickly informed of key issues and is designed to be read in conjunction with the final determination report (not as a substitute).

Technical appendices

The following appendices provide supporting and other information:

- Appendix A: Minister's delegation
- Appendix B: Submissions and references
- Appendix C: Network cost approach (small customers)
- Appendix D: Jurisdictional scheme charges
- Appendix E: Energy cost approach
- Appendix F: Cost pass-through approach
- Appendix G: Obsolete tariffs (customer impacts)
- Appendix H: Data used to estimate customer impacts
- Appendix I: Build-up of final notified prices
- Appendix J: DMO bill comparison and adjustment
- Appendix K: Gazette notice.

2 INDICATIVE BILL IMPACTS OF FINAL NOTIFIED PRICES

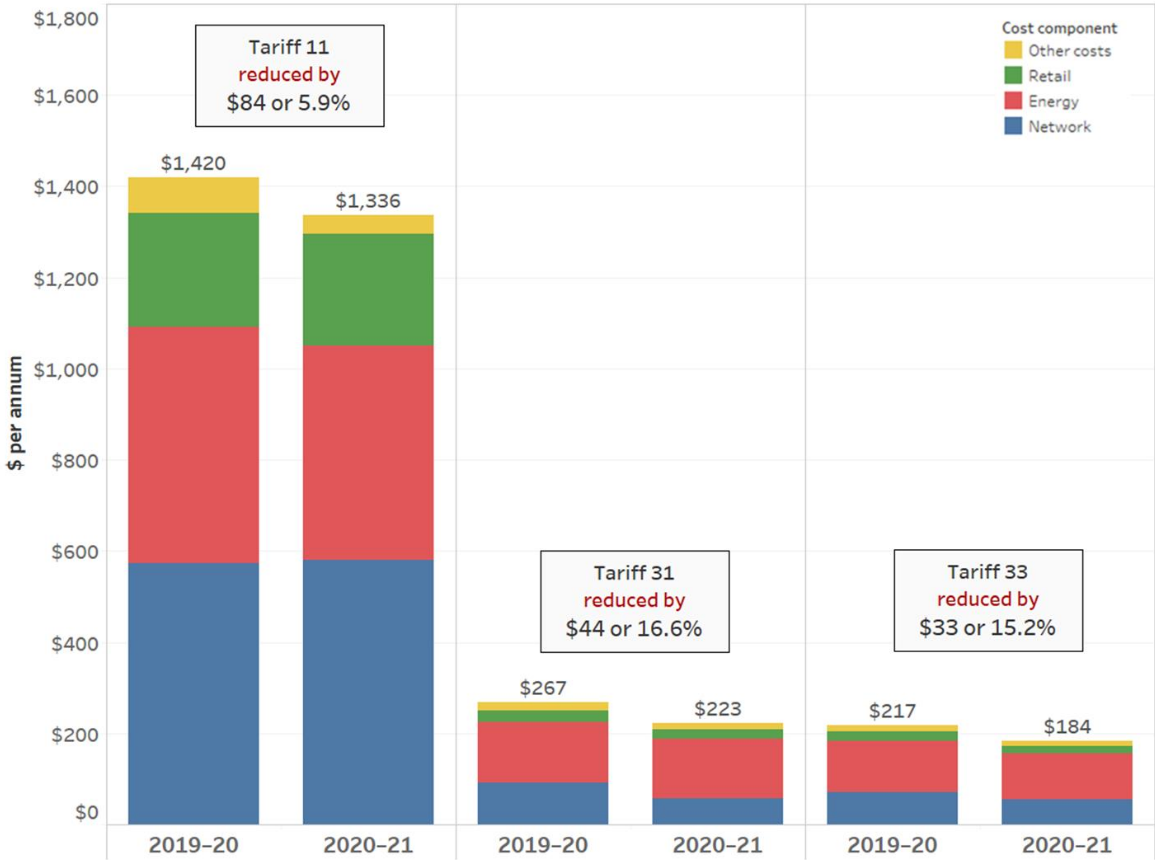
Overall, typical customers on all major tariffs can expect a reduction in their electricity bill based on notified prices in 2020–21. These reductions are largely due to an expected decrease in the network and energy costs that make up notified prices for 2020–21 (see chapter 4).

This chapter provides an indication of the electricity bill that a typical customer[9] would pay under 2020–21 notified prices compared to the bill using 2019–20 notified prices. Importantly, customers with different levels or patterns of usage, compared to the typical customer, may have different bill impacts.

2.1 Residential customers

Typical customers on the main residential tariffs (tariffs 11, 31 and 33[10]) are expected to pay around 5.9 to 16.6 per cent less for their electricity in 2020–21 (see Figure 1).[11]

Figure 1 Bills for a typical residential customer, 2019–20 and 2020–21 (incl. GST)



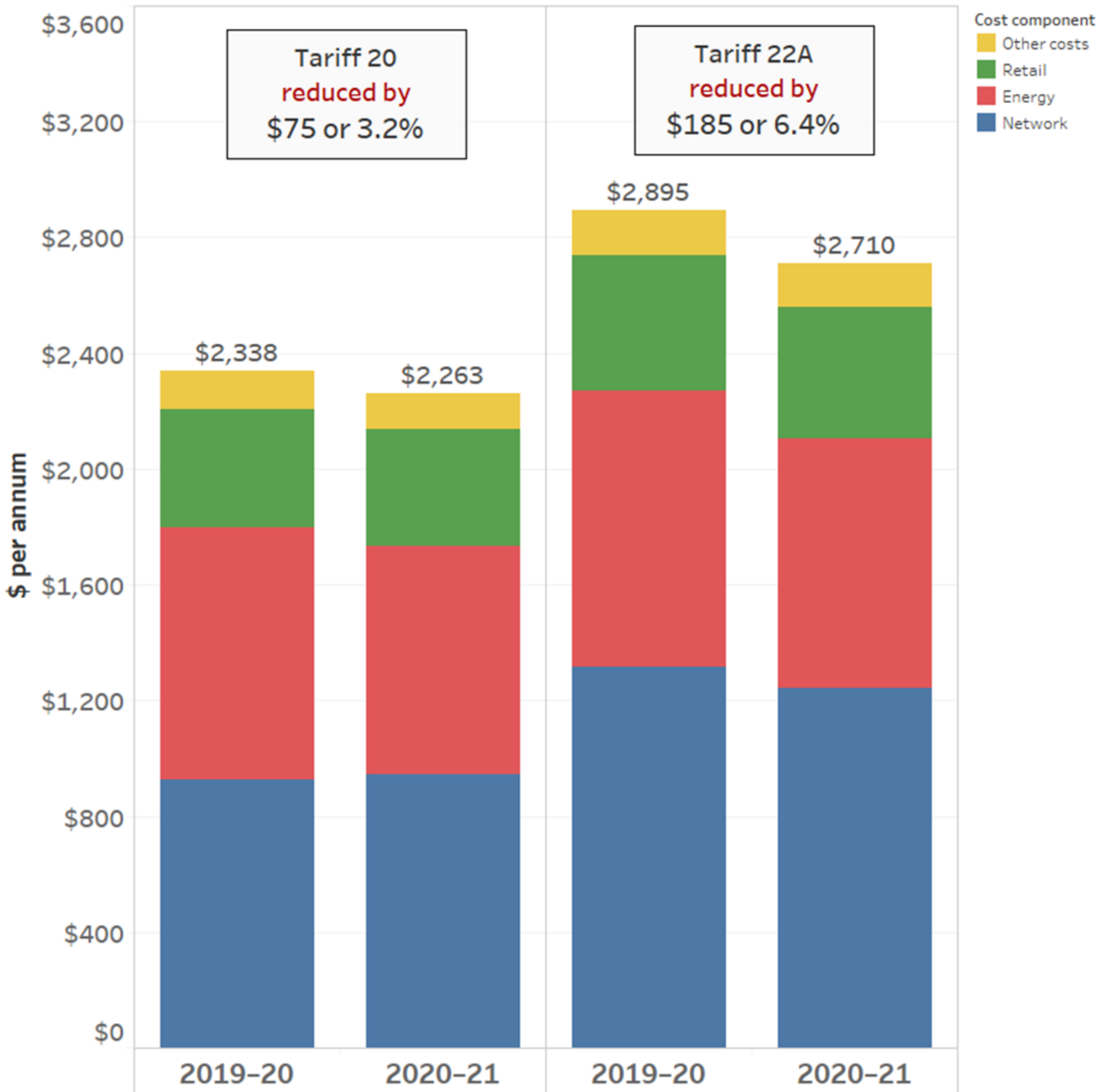
Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

[9] The typical customer for a given tariff is the median or middle customer in terms of consumption among all customers on the same tariff in regional Queensland (Ergon Retail consumption data used—see Appendix H).
[10] Most residential customers are on tariff 11, but many customers also access controlled load tariffs—tariffs 31 and 33—for appliances that do not require a constant supply of electricity (e.g. hot water systems and pool pumps).
[11] Metering charges are excluded from the bill impact analysis.

2.2 Small business customers

Typical customers on the main small business tariffs (tariffs 20 and 22A[12]) are expected to pay around 3.2 to 6.4 per cent less for their electricity in 2020–21 (see Figure 2).[13]

Figure 2 Bills for typical small business customers, 2019–20 and 2020–21 (incl. GST)



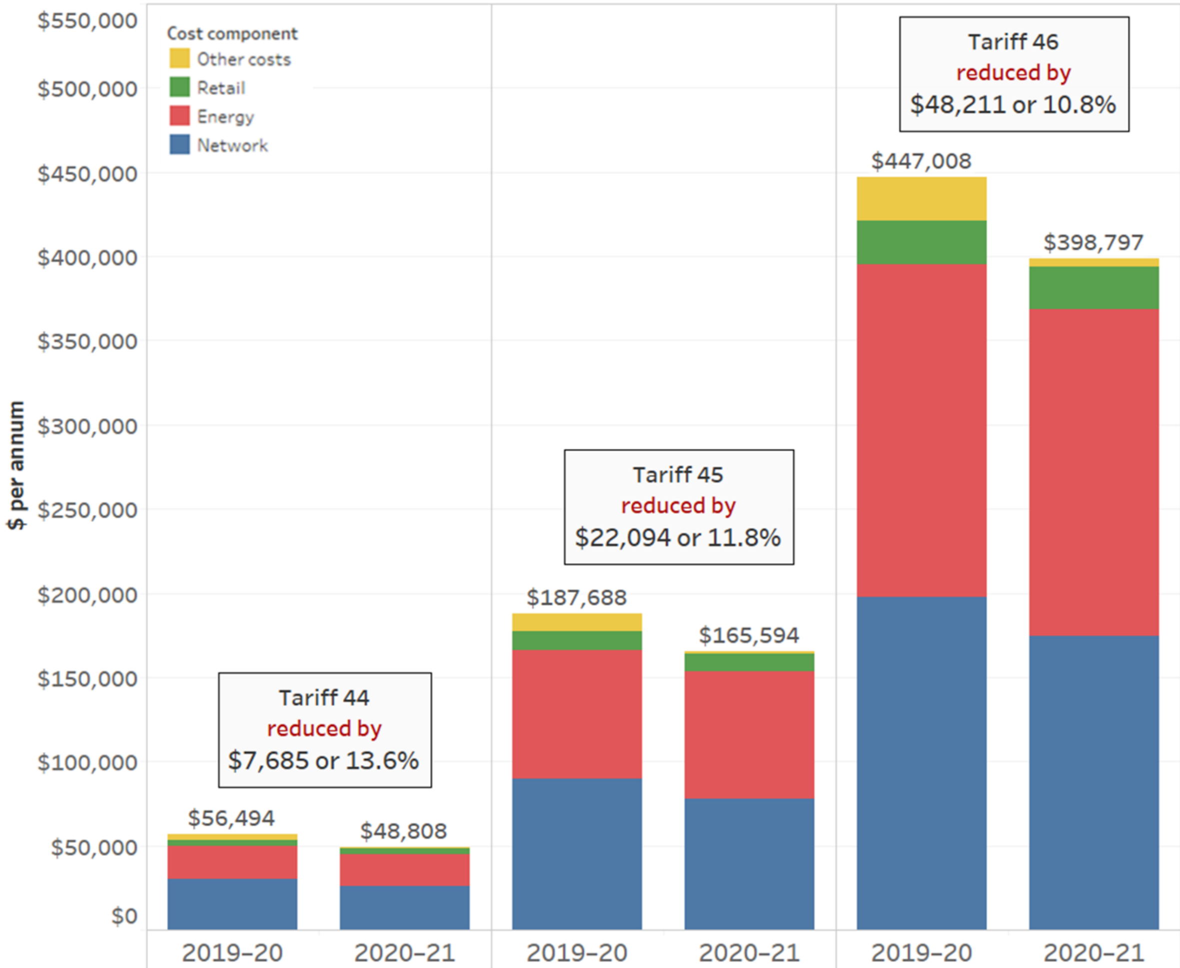
Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

[12] Tariff 20 is a flat-rate tariff, and tariff 22A is a time-of-use tariff.
[13] Metering charges are excluded from the bill impact analysis.

2.3 Large business customers

Typical customers on tariff 44, 45 or 46 are expected to pay around 10.8 to 13.6 per cent less for their electricity in 2020–21 (see Figure 3).[14]

Figure 3 Bills for typical large business customers, 2019–20 and 2020–21 (incl. GST)



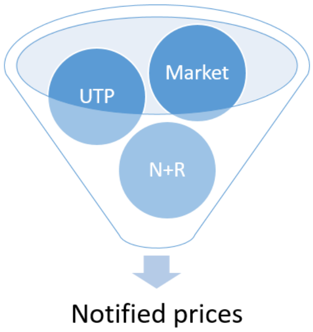
Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

[14] Metering charges are excluded from the bill impact analysis.

3 OVERARCHING FRAMEWORK—POLICY AND PRICING MATTERS

This chapter sets out key overarching framework matters that influenced our review and final determination of notified prices. The matters considered are:

- the market environment (section 3.1)
- the approach for setting notified prices (section 3.2)
- new matters in the delegation affecting notified prices and tariffs (section 3.3).



3.1 Market environment

The electricity sector is undergoing substantial reforms, including ongoing network tariff reforms (part of the regulatory decisions on network costs and structures for the electricity distributors in Queensland, Energex and Ergon Distribution).

This year, the Minister asked us to consider the market environment in setting prices. This includes managing the potential impacts on retail customers from the network tariff reforms and ensuring regional customers benefit from the protections provided by the uniform tariff policy (UTP).

More specifically, the delegation requires us to consider matters arising from two reviews undertaken by the Australian Energy Regulator (AER):

- 2020–25 regulatory determination process for distributors[15]—the AER sets network revenues and tariffs for electricity distributors in Queensland. As part of this process, Energy Queensland (EQ) (the parent company of Energex and Ergon Distribution) submitted a Tariff Structure Statement (TSS) for each distributor, proposing new network tariffs with more complex structures to facilitate a move towards greater cost reflectivity
- default market offer (DMO)—the AER sets a DMO that limits the prices charged to residential and small business customers on standard retail contracts in south east Queensland (SEQ). The DMO was first introduced in mid-2019. A DMO to apply from mid-2020 was approved by the AER on 30 April 2020.

Notably, the complex and evolving nature of the 2020–25 TSS and delays to the AER's pricing process timeframe[16] meant there was less certainty within our review timeframe on the network tariff structures and prices that would apply. The AER is expected to publish the approved network prices for 2020–21 on 24 June 2020. The network tariff reforms, including key processes, TSS milestones and timeframes, are summarised in Box 1 below.

In addition, the market environment has been impacted by the recent coronavirus pandemic. There is uncertainty around the potential implications of this, including the impact on electricity prices.

[15] The AER website provides more information on these reviews (including the process and timing), for example, Ergon Energy—Determination 2020–25 and Energex—Determination 2020–25.

[16] See the AER's annual pricing process timeline as updated on 28 May 2020, at https://www.aer.gov.au/system/files/AER%20-%20Pricing%20Timeline%20Process%20-%20Updated%2029%20May%202020_0.pdf.

Box 1: Network tariff reforms

EQ proposed to replace the flat-rate network tariffs for small customers[17] in SEQ with more complex network tariffs (as default tariffs) from 2020–21 onwards. The AER is considering this proposal as part of the 2020–25 regulatory determination process.

The form of the new network tariffs continues to evolve—EQ has amended its TSS submission three times since its first submission (January 2019). Due to the complexity of the process, the AER's draft decision was delayed from September to October 2019.

In its draft decision, the AER indicated that further substantial changes to the TSS were required for EQ to comply with the National Electricity Rules. In response, EQ made substantial changes to its June 2019 TSS proposals and submitted another revised proposal in December 2019.

In summary, EQ's December 2019 proposal included:[18]

- for the Energex area—four new demand tariffs, two new time-of-use (TOU) tariffs, new controlled load tariffs for small and large business customers and a new tariff, a wide inclining fixed tariff (WIFT)[19], for small business customers
- for the Ergon area—three new transitional network tariffs for customers on obsolete retail tariffs, three new TOU tariffs, five new demand tariffs, new controlled load tariffs for small and large business customers, and a WIFT for small business customers.

Some of the new tariffs summarised above are transitional—designed to minimise the impact on customers transitioning to the new cost-reflective network tariffs.

Since December 2019, the AER updated its annual pricing process timeline and extended the timing for making its final revenue and TSS determinations for Energex and Ergon Distribution. In late May 2020, to assist stakeholders to prepare for the 2020–21 network pricing arrangements, the AER published initial pricing proposals from Energex and Ergon Distribution (including proposed prices to apply from 1 July 2020), ahead of formal pricing proposals submitted on 10 June 2020.

In line with the AER's updated timeline:

- 5 June 2020—the AER published final revenue and TSS determinations for Energex and Ergon Distribution
- 24 June 2020—the AER will publish the approved Energex and Ergon Distribution network prices for 2020–21.

[17] Small customers with new and existing digital meters.
[18] For more information on EQ's tariff package and strategy, see its December 2019 TSS proposal, which is available on the AER website.
[19] The WIFT is a network tariff with an inclining block structure for fixed charges.

3.2 Approach for setting notified prices

3.2.1 Matters in the delegation

The terms of the delegation require us to consider:

- the Queensland Government's UTP—which provides that, wherever possible, customers of the same class should pay no more for their electricity, and should pay for their electricity via similar price structures, regardless of their geographic location
- use of the network (N) plus retail (R) cost build-up methodology when setting notified prices, where the N component (network cost) is treated as a pass-through and the R component (energy and retail costs) is determined by the QCA. Other specific matters include, when determining the N component, considering an alternative method where N cannot be treated as a pass-through due to price and structure uncertainty associated with network tariff reforms.

The Minister said it was important that 'regional customers continue to access price structures that are similar to those accessed by the majority of similar southeast Queensland customers' and, where practicable, customers are 'provided new and additional choice of retail tariffs resulting from the network tariff reform agenda'.[20]

While the UTP and N+R methodology are broadly consistent with previous determinations, some matters are new to this review, such as the tariff structure considerations under the UTP, and the additional flexibility provided under the N+R methodology when setting prices.

In making this final determination, we set notified prices having regard to:

- UTP cost considerations, noting in the past we based prices on:
  - for small customers[21]—the costs of supplying small customers in SEQ
  - for large customers[22]—the costs of supply in the Ergon Distribution area that has the lowest cost of supply and that is connected to the National Electricity Market (i.e. east zone, transmission region one)
- UTP tariff structure considerations and the resulting price-setting approach, where the delegation directs us to consider:
  - maintaining existing retail tariffs and structures, including considerations if underlying network tariffs are altered or removed
  - potentially aligning existing retail tariffs with proposed network tariffs
  - identifying options for introducing new retail tariffs based on proposed new network tariffs
- depending on the UTP considerations, using the N+R price setting methodology under:

[20] Minister's cover letter, p. 1 (Appendix A).

[21] For the purposes of this report, 'small customer' is a general reference to residential, small business and unmetered supply (other than street lighting) customers, unless otherwise indicated.

[22] For the purposes of this report, 'large customer' is a general reference to large business, very large business and street lighting customers, unless otherwise indicated.

- the standard approach—building up notified prices using the network tariffs as the basis for determining the structure of retail tariffs (i.e. passing through the N component) and adding the R component (i.e. energy and retail costs) determined by us
- the alternative approach—maintaining the existing suite of retail tariffs, by adjusting the current N component using a price indexation methodology and adding the R component (i.e. energy and retail costs) determined by us.

3.2.2 Stakeholder comments

Stakeholders strongly supported the continued use of the UTP to set notified prices.[23] Many stakeholders said the cost of electricity continues to be a key issue in regional Queensland[24] and must be 'front of mind' when setting prices so customers do not pay 'a cent more than they should have to.'[25]

Some stakeholders raised alternative ways to align prices for small customers in regional Queensland with those in SEQ, as required under the UTP—for example, by aligning notified prices with prices under SEQ market contract offers (rather than standard contract offers), or potentially averaging all prices in SEQ so that regional prices would better reflect what SEQ customers pay.[26]

There was broad consensus among stakeholders to maintain the existing retail tariff structures for notified prices in this price determination.[27] Stakeholders said this would allow new tariffs to be provided alongside existing tariffs, giving stakeholders an opportunity to either access the new tariffs on an opt-in basis[28], or at least compare the new tariffs with those currently available.[29] EQ suggested that, as part of our next price determination, we should consult on how long customers should be able to access existing tariffs whose underlying network tariffs are removed, and that access should be closed off to new customers.[30]

Stakeholders generally considered the recent network tariff reforms and introduction of new retail tariffs would benefit customers, including by:

- transitioning customers towards more cost reflective pricing—EQ said regional customers would benefit from the reforms and would be able to respond to appropriate price signals from more cost-reflective tariffs. Also, that this would provide a consistent approach to cost reflective tariffs likely to be offered by retailers in SEQ[31]
- providing new retail tariff structures—stakeholders supported having additional optionality; and EQ said it received widespread support from customers during its TSS consultation process on the new network tariff structures (to be used as the basis for developing the new retail tariff structures).[32]

[23] Kalamia, sub. 5, p. 2; Cotton Australia, sub. 3, p. 5; EQ, sub. 4, attachment, p. 1; QCOSS, sub. 7, attachment, pp. 3, 12–13.
[24] ASMC, sub. 1, pp. 1–2; Cotton Australia, sub. 3, p. 1; Kalamia, sub. 5, pp. 1–2; PV Water, sub. 17, p. 2.
[25] QCOSS, sub. 7, p. 1, sub. 18, p. 1, attachment, p. 2.
[26] Cotton Australia, sub. 3, p. 6; Kalamia, sub. 5, p. 2.
[27] QCOSS, sub. 7, attachment, pp. 4–5, sub. 18, attachment, p. 8; EQ, sub. 14, attachment, p. 5.
[28] QCOSS, sub. 7, p. 2.
[29] Cotton Australia, sub. 3, p. 6.
[30] EQ, sub. 4, attachment, p. 14, sub. 14, attachment, p. 5.
[31] EQ, sub. 4, attachment, p. 1, sub. 14, attachment, p. 4.
[32] EQ, sub. 14, attachment, p. 4.

EQ said it strongly supports introducing new retail tariffs as soon as possible and considered that some can be introduced from 1 July 2020.[33] However, it noted several issues would need to be resolved, including that customers generally prefer simplicity over complexity. Also, it is important to consider how retailers will package the new network tariffs into retail tariffs to appropriately reflect the intent of the UTP.[34] EQ said that while SEQ retailers would likely offer demand tariffs as an option, uptake may be low initially, but it was still beneficial to introduce them into the notified prices for customers (to assist the transition to more complex pricing structures) and retailers (to apply learnings to support less sophisticated customers making the transition).[35]

There was particular interest and stakeholder support for introducing retail tariffs based on new network load control tariffs during this determination. Several stakeholders considered there is sufficient certainty about the terms and conditions of these tariffs.[36] EQ also noted a number of customers are involved in load control tariff trials and, without new retail load control tariffs, they may no longer have a load control option available to them.[37]

Other stakeholders said a more cautious approach should be taken to introducing new retail tariffs, given the uncertainties around how any changes to network tariffs would affect retail tariff structures in SEQ.[38] QCOSS said while now may not be the optimal time, it supports introduction of new retail tariffs in the future, with adequate consultation.[39] QCOSS also recommended we take on a longer-term monitoring role of the implementation of new retail tariffs, such as through an expansion of the QCA's existing SEQ retail monitoring role.[40]

3.2.3 Analysis and final determination

Having regard to the relevant factors, stakeholder comments and our own analysis, we applied the UTP and N+R methodology to set notified prices in this final determination.

Two key matters are relevant to assessing the UTP and N+R methodology when setting prices:

- price levels
- tariff structures and the availability of tariffs.

Price levels

We are mindful the magnitude of electricity prices is a primary concern for most stakeholders. Customers in the regions, from broader consumer groups to industry specific consumers, raised concerns around cost pressures and affordability in regional Queensland, including with respect to electricity costs and the notified prices we set.

This year, we have continued setting notified prices in accordance with the Queensland Government's UTP. The application of the UTP leads to notified prices being set lower than they otherwise would be, by basing prices on lower cost of supply areas, that is:

- for small customers—the cost of supplying small customers in SEQ

[33] EQ, sub. 14, attachment, pp. 3–4.
[34] EQ, sub. 4, attachment, p. 1.
[35] EQ, sub. 14, attachment, pp. 3–4.
[36] BRIG, sub. 10, pp. 2–3; Cotton Australia, sub. 13, pp. 1–2; Canegrowers, sub. 11, p. 3; EQ, sub. 14, attachment, p. 4.
[37] EQ, sub. 14, attachment, p. 4.
[38] NSA, sub. 6, p. 1; Queensland Consumers' Association, sub. 8, p. 1; QCOSS, sub. 7, pp. 1–2 and attachment, pp. 4–5, 13, sub. 18, p. 2 and attachment, pp. 8–9.
[39] QCOSS, sub. 7, pp. 1–2, attachment, pp. 4–5, 13, sub. 18, pp. 8–9.
[40] QCOSS, sub. 18, p. 2; attachment, p. 9.

- for large customers—the costs of supplying large customers in the Ergon Distribution area with the lowest cost of supply that is connected to the National Electricity Market (i.e. east zone, transmission region one).

This approach is consistent with previous price determinations and, over time, it has benefitted most customers who would otherwise pay higher electricity prices (due to the higher cost of supplying electricity in regional Queensland). It relies on ongoing Queensland Government funding commitments—for 2019–20, around $498 million was budgeted to provide subsidised electricity prices for regional customers.[41]

Tariff structures and the availability of tariffs

In accordance with the N+R methodology for setting notified prices, network tariffs are used as the basis for setting retail tariffs. As noted above, there are significant changes arising from the network reforms to the underlying network tariffs for retail tariffs—particularly those in respect of small customers.

The implications of these network tariff reforms for retail tariffs is a key matter for our determination. For example, we need to consider whether to maintain existing retail tariffs, and whether to establish new retail tariffs to reflect the new network tariffs.

Small customers

Our final position is to maintain the existing suite of retail tariffs and structures when setting notified prices for small customers in regional Queensland, and not to introduce new retail tariffs that reflect the recently approved new network tariffs.

Given the extent of network tariff reforms, and revisions made to these reforms as the network determination process has evolved, we have decided to maintain existing standard retail tariffs. This should minimise the disruption to customers on existing retail tariffs, who otherwise may have been forced to switch to alternative retail tariffs based on new or altered network tariffs. This is also consistent with the delegation and the Minister's expectations that customers are not adversely impacted as a result of the ongoing network reforms.

Our decision to maintain existing retail tariffs has implications for determining the network cost component for some small customer tariffs, particularly some of the less commonly accessed demand and time-of-use tariffs that no longer have (or align with) underlying network tariffs (discussed in chapter 4).

We considered whether to introduce new retail tariff structures based on the new network tariffs, but decided it was not appropriate at this time. The new network tariff structures are complex and, importantly, as EQ pointed to, a key consideration is how retailers will package Energex's new network tariffs into SEQ customer retail tariffs. We consider this is particularly relevant, given the government's UTP provides that, among other things, customers of the same class should pay for their electricity via similar price structures, regardless of their geographic location. Also relevant, as indicated by EQ, customers generally prefer simplicity over complexity.

At this time, we are unable to anticipate how retailers in SEQ will respond, or whether they will offer tariff options based on the more complex suite of EQ network tariff structures that were recently approved. In the past, more complex tariff options are generally less popular among retailers and customers alike. As such, it is not clear that introducing new retail tariffs (based on the more complex new network tariffs) will be consistent with tariffs offered by retailers in SEQ

[41] Queensland Government, *Queensland Budget 2019–20—Budget Strategy and Outlook: Budget Paper No. 2*, June 2019 p. 20.

in the coming year, as EQ has suggested. Further, EQ submitted that SEQ retailers are likely to offer new demand tariffs as options, but again this is not guaranteed, as it is possible that retailers will not offer these new retail tariffs at all—given that customers generally prefer simpler pricing structures.

We appreciate some customers would prefer new tariffs to be introduced in this determination—for example, to provide them with the opportunity to compare the impacts of different tariff options on their bills and to be able to access those new tariffs. We also note a number of customers would prefer new load control tariffs to be introduced, given the potential benefits customers expect these tariffs provide.

However, because the SEQ market response is uncertain and we need to consider the tariff structure considerations under the UTP, the introduction of new retail tariffs needs to be carefully considered. Further, given the changes in the market (including the network tariff reforms) and the amendments to the UTP for small customers, we also consider there may be issues with the application of the N+R approach going forward.

Applying the N+R methodology as we have done to date, results in a retail tariff structure that duplicates the underlying network tariff structure, where retailers are assumed to pass-through the network charges to customers. However, the network tariff reform means that retailers in SEQ are now more likely to offer retail tariffs with structures that differ from the underlying network tariffs. This is due to a mismatch between customer preferences (who likely prefer simpler pricing structures) and the introduction of network tariffs with complex structures (due to the tariff reforms). Implementing the N+R approach in such an environment will be challenging because there is limited transparency on how retailers in SEQ will pass on network charges and manage the financial risks associated with the misalignment of network and retail tariff structures.

With regard to the new load control network tariffs, we are also unable to establish new retail tariffs based on these at this time, as we do not have sufficient information on the relevant load profiles. This information is important for us to be able to appropriately determine the energy costs of these tariffs. This is particularly an issue for these new tariffs because, in contrast to existing load control tariffs, which are largely used by residential customers, the new tariffs are targeted for use in a commercial capacity, including for large businesses for the first time. For a detailed explanation of our considerations, refer to Appendix E.

We consider our approach is consistent with the UTP and appropriately addresses stakeholder concerns. It is also consistent with government and stakeholder expectations that existing standard retail tariffs be retained.

Large customers

In contrast to the network tariff reforms for small customers, there are less extensive reforms to network tariffs for large customers. As such, there is a greater similarity between existing retail tariffs and the network tariffs for large customers.

Our final position is to base notified prices on the large customer network tariffs that have similar structures to those currently in place. This means that notified prices are based on tariff structures that are, in all material respects, unchanged from those currently available (i.e. since the underlying network tariffs for large customers are substantially consistent with structures that apply now).

We decided not to establish new retail tariffs based on new network tariffs for large customers, namely the new network default time-of-use demand tariff and load control tariffs. Similar to our position in respect of small customers, we consider there has been insufficient certainty within our review timeframe to incorporate these within notified prices. For instance, as discussed above in respect of small customers, we do not have enough information about the relevant load profiles of the new load control network tariffs to be able to appropriately determine the energy costs of these tariffs at this time.[42]

However, there are some aspects of the network tariff reforms that we have incorporated into notified prices:

- removal of excess kVAr charges[43] that were previously included in connection asset customer (CAC) and Individually calculated customer (ICC) tariffs, which reflects the removal of these charges from the equivalent network tariffs[44]
- introduction of kilovolt ampere (kVA) demand-based charging parameters for retail tariffs 44, 45 and 46, with kilowatt (kW) charging available where customer metering does not support kVA billing.[45] EQ has raised concerns about the challenges facing customers transitioning to the kVA charging parameter in the current economic climate and covid-19 environment, including the cost and availability of power factor correction equipment that customers may need to install in order to benefit from kVA tariffs.[46] In light of these concerns, we consider it reasonable to accept EQ's proposal for customers to be able to opt in to the use of kVA demand-based charging parameters during the period of this price determination. For customers with type 6 metering that is replaced with type 1 to 4 metering due to action not initiated by the customer, we have also decided to provide a 12-month opt-in period for kVA charging from the meter replacement date. This should allow customers, whose metering otherwise supports kVA billing data, time to prepare for the transition to kVA demand-based charging parameters.

We otherwise consider that large customers are sophisticated and well-equipped enough to assess and manage the impacts of these changes to tariff structures at the individual customer level.

In our draft determination, we proposed the removal of tariffs 52A–C (time-of-use demand tariffs for CACs) to reflect the proposed retirement of the underlying network tariffs for these retail tariffs. However, the underlying network tariffs will no longer be retired and, as such, we have revised our position and retained these retail tariffs.[47]

[42] For a detailed explanation of our considerations, see Appendix E and ACIL Allen's final report (available on our website).

[43] An excess kVAr charge is an excess reactive power charge ($/excess kVAr/month), which applies to the kVAr used by a customer that exceeds the customer's permissible quantity. A customer's permissible kVAr quantity is determined by the customer's authorised demand and the compliant power factor as per the National Electricity Rules.

[44] AER, *Ergon Energy Distribution Determination 2020 to 2025—Overview*, final decision, June 2020, attachment 18: tariff structure statement, p. 10.

[45] Ergon Energy, *Revised Tariff Structure Statement—Explanatory Notes 2020–25*, December 2019, pp. 44–45; AER, *Ergon Energy Distribution Determination 2020 to 2025—Amended Tariff Structure Statement, final decision, June 2020*, pp. 13–14.

[46] EQ, sub. 14, attachment, pp. 5–6.

[47] AER, *Ergon Energy Distribution Determination 2020 to 2025—Overview*, final decision, June 2020, attachment 18: tariff structure statement, pp. 26–27.

3.3 New pricing matters

3.3.1 Solar bonus scheme (SBS) costs

In February 2020, EQ advised that Energex and Ergon Distribution intended to include jurisdictional scheme amounts, which include SBS and Australian Energy Market Commission (AEMC) levy costs, in their respective annual pricing proposals for network tariffs (see Appendix D). These proposals were submitted to the AER on 26 May 2020. The AER is expected provide its decision on these proposals in late June 2020 (with network charges to take effect from 1 July 2020).

Stakeholder submissions

EQ said we should include jurisdictional scheme amounts (such as SBS costs) as part of our determination of notified prices.[48] It noted this is not an EQ decision, but a requirement of the National Electricity Rules.[49]

Other stakeholders did not support the inclusion of SBS costs in notified prices, with some considering we should seek a Ministerial direction on this matter before including these costs.[50] In particular, stakeholders said these costs should continue to be funded by general state revenue,[51] particularly since it will have a negative impact on the affordability of electricity for regional customers[52] in this time of exacerbated hardship brought about by covid-19.[53] QCOSS said jurisdictional scheme amounts should only be included if the AER includes those costs in the approved network charges.[54]

Analysis and final position

Having regard to the relevant factors, stakeholder comments and our own analysis, our decision is to reflect the jurisdictional scheme amounts in notified prices (see Appendix D).

Under the National Electricity Law, distributors are entitled to recover jurisdictional scheme amounts (such as SBS costs) through network charges. In accordance with the N+R approach to setting notified prices, we pass through jurisdictional scheme amounts as part of the network component of notified prices, given they are included in the AER-approved network prices. This has also been the approach we have taken in previous determinations, excluding determinations between 2017–18 and 2019–20, because of the Queensland Government's 2017 direction to EQ to remove SBS costs from network prices over that period.

We are mindful that consumers would prefer it if jurisdictional scheme amounts were not included in notified prices, or only included on further advice from the Minister. However, for the reasons we discussed above, including that there is an appropriate legal basis for including these costs and they are included in the network prices proposed to apply from 1 July 2020, they necessarily are reflected in notified prices.

We have used the jurisdictional scheme amounts included in the distributors' annual pricing proposals to the AER (provided on 26 May 2020). The use of proposed amounts (rather than those

[48] EQ, sub. 4, attachment, p. 3.
[49] EQ, sub. 14, attachment, p. 8.
[50] QEUN, sub. 20, pp. 21–23; COTA, sub. 12, p. 2; QFF, sub. 9, p. 2; Cotton Australia, sub. 3, p. 7, sub. 13, p. 2; Canegrowers, sub. 11, p. 4; QCOSS, sub. 18, p. 2.
[51] COTA, sub. 12, p. 2; Cotton Australia, sub. 13, p. 2.
[52] QCOSS, sub. 18, p. 2.
[53] COTA, sub. 12, p. 2.
[54] QCOSS, sub. 18, attachment, p. 12.

approved by the AER) is consistent with our practice in previous years, given the timing of our respective determination processes. Discrepancies with the AER's determination could be subject to a cost pass-through mechanism in the next determination.

3.3.2 Nomination of default tariffs

The terms of the delegation require us to consider the 'nomination of a primary tariff for each class of small customer to apply to a customer's electricity account in the event the customer does not nominate a primary tariff when opening an electricity account**.**'

Additionally, the Minister's cover letter said we should consider nominating tariff 11 as the default residential tariff, and tariff 20 as the default small business tariff. It also stated that 'this default designation should not limit customers from selecting alternative tariffs they are eligible for if they choose to do so'.[55]

Analysis and final position

Having regard to the relevant factors, stakeholder comments and our own analysis, we have implemented the arrangements for nominating default tariffs consistent with the delegation. That is, nominating tariff 11 as the default tariff for a residential customer, and tariff 20 as the default tariff for a small business customer, who does not nominate a tariff upon establishing an electricity account.

Given the network reforms underway, this will provide certainty on the retail tariff these customers will be assigned to in the event they do not nominate a tariff. This is consistent with government expectations and is broadly supported by stakeholders.[56]

This does not restrict a customer from choosing an alternative tariff when they establish an account (or switching from the default tariff to another tariff at a later date).

3.3.3 Individually calculated customer (ICC) tariffs

Individually calculated customers (ICCs) are very large business customers generally consuming over 40 GWh each year. Generally, these are large industrial users, such as smelters and other heavy industry customers.

The terms of the delegation require us to consider, for ICC tariffs, 'a methodology that allows for the pass-through of the customers' individual network charges'. This matter has not formed part of previous delegations and is therefore a new matter to consider for this price determination.

The Minister has described the policy intent as follows:

> Ergon distribution has also proposed to the AER to reassign some Connection Asset Customers (CAC) to Individually Calculated Customers (ICC) in 2020-21 when they have been identified as an outlier to their costs to serve. This has the potential to significantly lower the network charges for some of these customers. The government considers it important that any potential reduction in network charges be passed through to customers via notified prices. However, to ensure existing ICC customers are no worse off, the QCA should also maintain Tariff 53.[57]

[55] The Minister's cover letter (Appendix A).

[56] Queensland Consumers' Association, sub. 8, p. 1; Kalamia, sub. 5, p. 2, sub. 15, p. 2; EQ, sub. 4, attachment, p. 4; QCOSS, sub. 7, p. 1, attachment, p. 6, sub. 18, attachment, p. 9.

[57] Minister's cover letter, p. 3 (Appendix A).

Stakeholder submissions

Stakeholders indicated support for the proposed reforms in respect of ICC tariffs. The Australian Sugar Milling Council said these initiatives have the potential to broadly benefit customers, including by improving cost transparency and increasing customer choice and flexibility.[58]

While not opposing the reforms, Cotton Australia said we must make specific efforts to ensure customers are consulted on the implications of being reclassified as ICC. It noted that, while Ergon Energy had preliminary discussions about this with cotton ginning companies, it is not clear to customers whether they would be better off or not.[59]

EQ identified issues we would need to consider in order to give effect to the ICC reforms, including how new site-specific retail tariffs will be established and published to ensure customer information is protected, as well as the application of retail and headroom amounts.[60]

Analysis and final position

Having regard to the relevant factors, stakeholder comments and our own analysis, we are introducing notified prices based on site-specific network charges. This provides optionality for customers and is in the interests of stakeholders, particularly those who would be otherwise worse off. This is also consistent with the government's intention to provide more options to customers on ICC tariffs. This results in:

- tariff 53 being maintained
- customers on ICC tariffs having the option of accessing a notified price based on the site-specific network charges (determined by the AER) and the non-N component (energy costs, retail costs and cost pass-through) determined by us.

To determine the non-N component of site-specific tariffs, we used the non-N component used for determining tariff 53. We consider this approach is appropriate, because we are determining tariff 53 for the same group of very large customers that will have access to site-specific tariffs.

We are not convinced it is appropriate for us to apply a more complex approach than the one we have proposed for setting the non-N component, as suggested by EQ.[61] Determining a non-N component for each site-specific tariff would be administratively complex. We would need to determine the non-N components by calculating variable retail costs as a percentage of other cost components (see Chapters 4 and 5), and each site-specific retail tariff has a different network cost component.

Further, we do not consider it appropriate to apply a more complex approach in order to set more tailored site-specific notified prices for ICCs. Notified prices are generally meant to act as a safety net for large customers, especially for those with access to market contracts (in areas where notified prices closely reflect the actual costs of supply). In other words, large customers should be encouraged to seek out more attractive market offers.

---

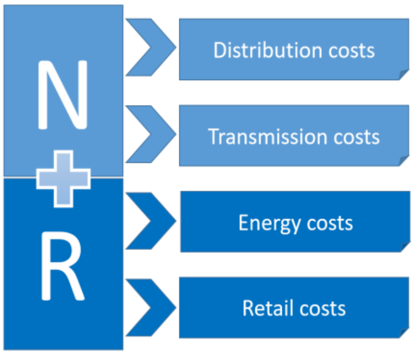
[58] ASMC, sub. 1, pp. 1–2.
[59] Cotton Australia, sub. 3, pp. 5–6.
[60] EQ, sub. 4, attachment, pp. 4–5, sub. 14, attachment, p. 6.
[61] In relation to the specific issue that EQ raised on the application of the non-N components with regard to the transmission use of system (TOUS) charges, we note that, for the underlying network tariff of tariff 53, both TUOS and distribution use of system (DUOS) charges are measured in kVA, and no TUOS charges were allocated to the demand component.

Given the nature of site-specific tariffs, it will be a matter for individual customers as to whether or not they will be better off under a site-specific tariff or taking up a market offer. We encourage customers to consider their options.

4 COST BUILD-UP COMPONENTS—INDIVIDUAL COST ELEMENTS

This chapter sets out our final position on issues related to the cost build-up components under the N+R approach, which we use to set notified prices.

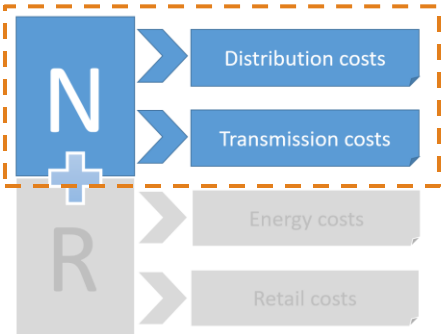
Many of these issues are identified in the delegation, which we must consider when setting notified prices. For instance, the Minister has provided additional matters for us to consider in determining the network component to reflect the network tariff reforms currently underway.



The individual cost elements include:

- the network (N) component—distribution and transmission costs associated with transporting electricity to customers
- the retail (R) component—the costs of buying electricity from the National Electricity Market and on-selling it to customers.

4.1 Network component



Network costs include the costs of transporting electricity through transmission and distribution networks. These costs are regulated by the AER.

The AER also regulates jurisdictional scheme charges, which form a component of network costs. In Queensland, these charges generally include the Solar Bonus Scheme (SBS) and AEMC levy costs. The proposed network prices for 2020–21 include jurisdictional scheme charges.[62]

Overall, total network costs are expected to:

- increase by 1.3 to 2.0 per cent for small customers on flat-rate tariffs
- decrease by 11.6 to 14.8 per cent for large customers, depending on the tariff.

The pricing approach we adopted this year (discussed in chapter 3) is to:

- for small customers—maintain the existing retail tariffs and structures
- for large customers—base the retail tariffs on network tariffs that have similar structures to those currently in place
- for both small and large customers—not introduce new retail tariffs based on the new network tariffs for Energex and Ergon Distribution recently approved as part of the AER’s network determination process.[63]

[62] See section 3.3.1 and Appendix D.

[63] The AER made its network determinations for Energex and Ergon Distribution on 5 June 2020, which included the AER's determination on each distributor's tariff structure statement.

In determining the N component of notified prices, we have taken into account the network tariff reforms that progressed while our review was underway. As such, for this price determination, it was necessary to consider whether to:

- pass through the network prices[64] to be approved by the AER (i.e. the standard approach), or
- apply a price indexation approach to reflect the changes in network costs determined by the AER.

4.1.1 Stakeholder submissions

Stakeholders raised concerns about the application of an indexation approach for determining the N component.

EQ did not support an indexation approach and said this would distort price signals, delay critical tariff reform and create a misalignment between retail and network tariffs.[65] In particular, it said this approach would result in a greater reduction in the N component of the retail tariff paid by a typical customer (compared with passing through approved network prices), meaning it would not reflect the cost of providing Energex's network services in south east Queensland, and would result in increases in the N component in future to correct for this over-adjustment.[66] It also noted this approach would result in a divergence between the N components of the time-of-use and demand tariffs (tariffs 12A and 14) and the Energex flat rate network tariff, which would not be consistent with the network cost equalisation principle typically applied to these tariffs.[67]

While EQ said AER-approved network prices should be applied to all regulated retail electricity tariffs, it considered that for small customers, at a minimum, the approved network prices should be applied for retail tariffs 11, 20, 31 and 33, given these include the proposed default retail tariffs and the majority of Ergon Energy Retail customers are on these tariffs.[68]

QCOSS and QEUN said we should use actual network prices in our final determination, because there should be no uncertainty of the price structures of network tariffs to apply, given the AER is due to approve prices by mid-June 2020. As such, they considered our ministerial delegation did not permit the use of a price indexation methodology in these circumstances.[69] Nonetheless, QCOSS noted retail tariffs 12A and 14 may no longer have underlying network tariff structures (once the new network tariffs are approved by the AER) and considered we needed to develop a different method of setting the N component for these two retail tariffs and consult on this prior to the final determination.[70] QEUN also said we should convene another public workshop as soon as we decide whether or not to use the indexation approach for network tariffs.[71]

Similarly, Canegrowers did not support the use of an indexation approach and said we should calculate cost-reflective retail tariffs based on the actual network prices.[72] It said using an indexation approach to 'smooth' the N component of retail prices between 2019–20 and 2020–21 would be inconsistent with the Electricity Act, because the N component would 'exceed any

[64] For the purposes of this report, 'network costs/prices' is a general reference to distribution and transmission costs/prices, unless otherwise indicated.
[65] EQ, sub. 4, attachment, p. 3, sub. 14, attachment, pp. 2–3.
[66] EQ, sub. 14, attachment, p. 2.
[67] EQ, sub. 14, attachment, p. 3.
[68] EQ, sub. 14, attachment, p. 2.
[69] QCOSS, sub. 7, attachment, pp. 7–8, sub. 18, attachment, pp. 10–11; QEUN, sub. 20, p. 21.
[70] QCOSS, sub. 18, attachment, pp. 10–12.
[71] QEUN, sub. 20, p. 21.
[72] Canegrowers, sub. 11, p. 3.

reasonable estimate of the actual costs of making, producing or supplying the goods and services'.[73]

4.1.2 Analysis and final decision

Having regard to the relevant factors, stakeholder comments and our own analysis, we have decided to determine the N component of notified prices by:

- for small customers:
  - passing through 2020–21 network prices to be approved by the AER (where the underlying network tariff structure is similar to an existing retail tariff (i.e. for tariffs 11, 20, 31, 33, 41 and 91))[74]
  - where the above is not possible, applying a price indexation approach to reflect the changes in network costs determined by the AER (specifically, where the existing retail tariff no longer has an underlying network tariff with a similar structure—i.e. for tariffs 12A, 14, 22A and 24)
- for large customers—passing through 2020–21 network prices to be approved by the AER.[75]

Small customers

In previous price determinations, under the standard N+R approach, we used the network prices to be approved by the AER as the basis for determining the N component.

Given our decision to maintain existing retail tariffs for small customers this year (see section 3.2.3), we are unable to use this approach in all instances. This is because EQ has proposed to retire certain network tariffs that underpin the existing retail tariffs.

Furthermore, we are unable to align all existing retail tariffs with the new network tariff structures and prices due to the material difference between the new network tariffs and the previous network (and retail) tariff structures.

However, since our draft determination, certainty has increased about the final form of network tariff structures and prices, particularly for Energex's flat-rate and existing controlled load network tariffs, that underpin existing regulated retail tariffs for small customers. We have taken this into account in this final determination.

Accordingly, we have used a mixture of the standard and indexation approach (where necessary) to determine the network costs for the purposes of this price determination.

Passing through network prices under the standard approach

For existing regulated retail tariffs that will continue to have underlying network tariffs, we have applied the standard N+R approach for determining the relevant N component—that is, by passing through the 2020–21 network prices to be approved by the AER.

This approach has been applied to retail tariffs 11, 20, 31, 33, 41 and 91, which all continue to have underlying network tariffs. A significant majority of small customers in regional Queensland

---

[73] Canegrowers, sub. 2, p. 2 and attachment, p. 15.

[74] The network prices passed through are based on Energex's initial pricing proposal submitted to the AER on 26 May 2020. The AER is expected to publish the approved network prices on 24 June 2020.

[75] The network prices passed through are based on Ergon Distribution's initial pricing proposal submitted to the AER on 26 May 2020. The AER is expected to publish the approved network prices on 24 June 2020.

are on one of these tariffs, which include the residential and small business flat rate tariffs that we have decided will become default retail tariffs (see section 3.3.2).

Due to the timing of our determination, we have used the 2020–21 pricing proposal Energex submitted to the AER on 26 May 2020 as the relevant network prices. The AER is expected to publish the approved network prices on 24 June 2020. If the AER's approved prices differ from those submitted by Energex, we will consider using a cost pass-through mechanism to adjust for material differences (see section 5.3), if we are delegated this task in the future. We incorporated jurisdictional scheme charges (chapter 3) into network costs for small customers, which reflects the inclusion of these charges in network prices to be determined by the AER.

Price indexation approach

For the remaining existing regulated retail tariffs that will not have an underlying network tariff, we have determined the N component by using a price indexation approach, specifically an 'X-factor' approach.[76] This approach allows for the pass-through of changes in network costs (as determined by the AER). This approach uses 2019–20 network costs as a starting point, which are then adjusted using the AER’s nominal X-factors. More details on the X-factor approach are available in Appendix C.

This approach has been applied to retail tariffs 12A, 14, 22A and 24.

We are mindful some stakeholders would have preferred further consultation around this matter, including prior to making our price determination. However, due to the timing of network pricing information becoming available (i.e. 26 May 2020), in conjunction with our own review timeframes, a further round of consultation prior to our final determination was not possible.

We note comments made by stakeholders about the application of an indexation approach, including whether this is consistent with the terms of reference for our review. In deciding on an appropriate approach, we have considered the policies, principles and other matters the ministerial delegation requires us to consider when determining notified prices. We acknowledge there is now greater certainty about the network tariff reforms, given the network tariff structures have now been determined by the AER, and that, at the time of our determination, network pricing proposals have been submitted to the AER for its approval. As such, we have passed through 2020–21 network prices for existing retail tariffs, where possible.

However, it is not possible to pass through 2020–21 network prices for all existing retail tariffs because there is not an underlying network tariff for all of these retail tariffs. At this time, we have also been unable to base the N component for those retail tariffs on an alternative suitable network tariff. Accordingly, we consider the indexation approach is necessary for these retail tariffs that no longer have an underlying network tariff. We note the indexation approach has not been applied widely in this determination; the N component for most existing retail tariffs, including the commonly used flat rate tariffs, is based on passing through 2020–21 network prices.

We also note EQ's concerns that an indexation approach will require adjustments to be made in future determinations to ‘rebase’ the N component. We consider the issue of rebasing retail tariffs could be considered in future price determinations if EQ amends (or ‘rebases’) network tariffs in future, including the extent to which existing retail tariffs should be maintained or

[76] As part of the revenue determination process, the AER produces five X-factors for the purposes of revenue smoothing (the X-factor for the first year is also known as P_0). Mathematically, X-factors are weights that are applied to allowable revenue for one year to calculate the allowable revenue for the next year using a CPI-X price formula.

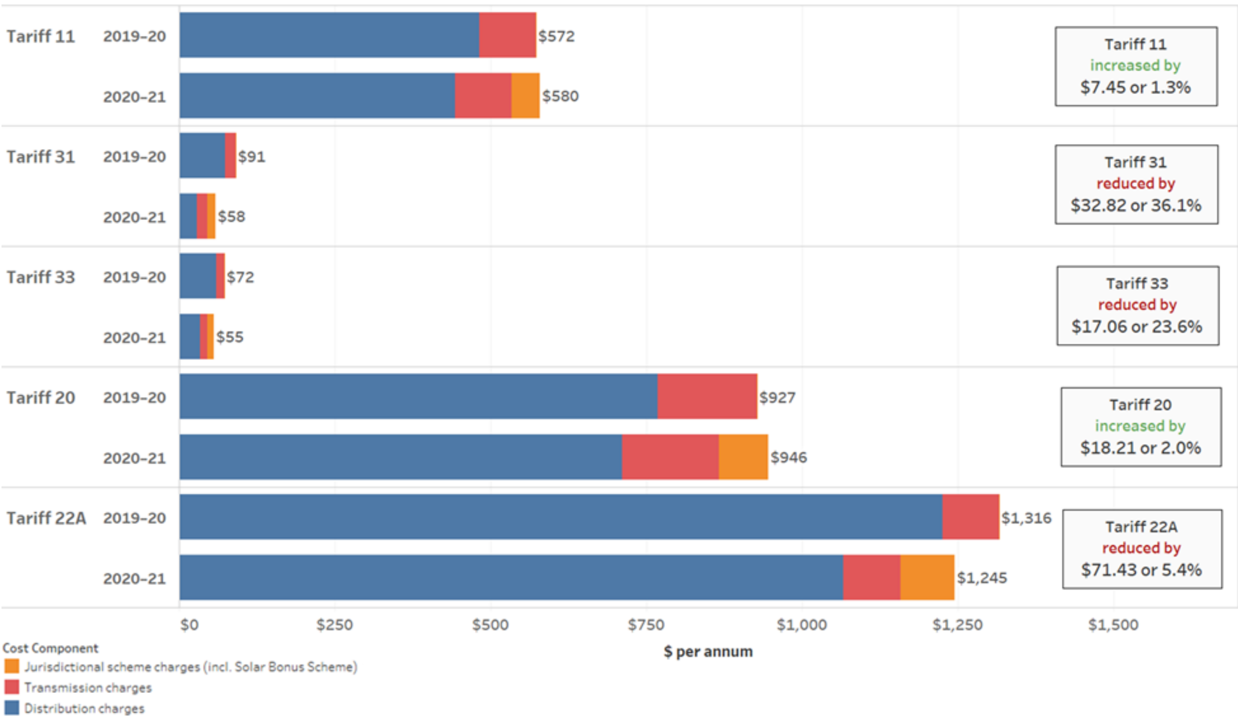
phased out. This is likely to be one of the issues arising from the network reforms that may impact future reviews.

Furthermore, we note other stakeholder concerns about the use of an indexation approach to 'smooth' the N component and about whether this would be consistent with the Electricity Act.[77] However, the indexation approach will not 'smooth' the N component over multiple years; it is an adjustment to reflect the change in network costs from 2019–20 to 2020–21. We use X-factors set by the AER in its network determination, which reflect the AER's determination of the efficient costs that transmission and distribution companies are entitled to recover. Accordingly, we consider the use of the indexation approach is appropriate under the current circumstances, as it reflects the underlying network costs, and we do not consider it is inconsistent with the Electricity Act.

We incorporated jurisdictional scheme charges (discussed in chapter 3) into network costs for small customers, which reflects the inclusion of these charges in network prices to be approved by the AER.

The following chart shows the network costs included in notified prices for small customers in 2020–21 compared to 2019–20.

Figure 4 Network costs—typical customers on small customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

Large customers

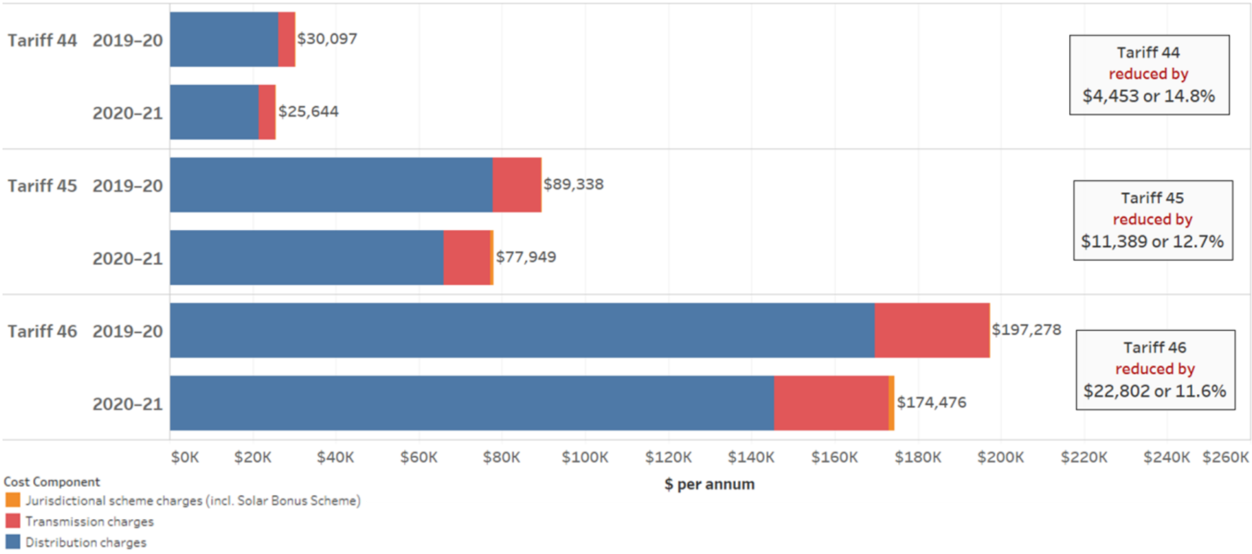
Given the similarities between the tariff structures of existing large customer retail tariffs and the new network tariffs, we have applied the standard N+R approach for determining the N component for large customer retail tariffs (including the street lighting retail tariff)—that is, by passing through the 2020–21 network prices to be approved by the AER.

[77] Canegrowers, sub. 2, p. 2 and attachment, p. 15.

Due to the timing of our determination, we have used Ergon Distribution's proposed prices for 2020–21 (as submitted to the AER on 26 May 2020) as the relevant network prices. The AER is expected to publish the approved network prices on 24 June 2020. If the AER's approved prices differ from those submitted by Ergon Distribution, we will consider using a cost pass-through mechanism to adjust for material differences (see section 5.3), if we are delegated this task in the future. We incorporated jurisdictional scheme charges (discussed in chapter 3) into network costs for large customers, which reflects the inclusion of these charges in network prices to be determined by the AER.

The following chart shows the network costs included in notified prices for large customers in 2020–21 compared to 2019–20.

Figure 5 Network costs—typical customers on large customer tariffs (GST incl.)



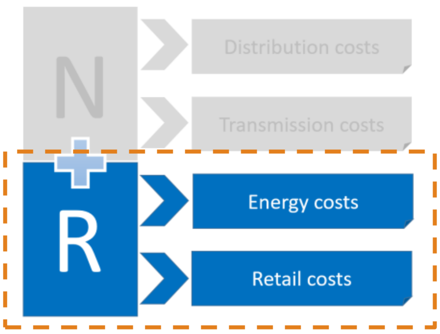
Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

4.2 Retail component

The R component consists of energy and retail costs. These include the costs of retailers purchasing electricity to supply to their customers, the costs of running their general operations, and a return for the risk they face by operating in the market.

We have used broadly the same approach to determine the R component this year:

- Total energy costs are expected to reduce by 3.9 per cent to 10.2 per cent for small customers, depending on the tariff, and by 1.9 per cent for large customers, across all tariffs.
- Total retail costs are expected to reduce by 1.7 per cent to 16.9 per cent for small customers, and 2.0 per cent to 5.2 per cent for large customers, depending on the tariff.



4.2.1 Energy costs

Energy costs include costs associated with wholesale energy costs (the costs of purchasing electricity from the National Electricity Market (NEM)), other energy costs and energy losses.

Consistent with previous years, we have engaged ACIL Allen to provide expert advice on energy costs.[78] Our position for this review is to estimate energy costs based on ACIL Allen's advice.

Stakeholder submissions

Stakeholders broadly supported us applying the same approach to estimate energy costs that we used in previous years. EQ noted that applying a consistent approach allows it to effectively manage the significant risks involved in purchasing electricity from the NEM.[79]

However, QEUN noted that wholesale spot prices in Queensland have declined since covid-19 restrictions were introduced. It submitted that we should engage a second consultant to estimate energy costs, and that we use the latest energy cost data possible, to capture the effects of covid-19.[80] QCOSS also considered that we should use a later data cut-off date for our energy cost analysis given the later timing of our final decision, compared to previous years.[81]

Canegrowers noted that since the onset of the covid-19 pandemic, the cost of electricity generation has fallen sharply, reflecting global reductions in the prices of oil, coal and LNG. Canegrowers submitted that we should revise our energy cost analysis to take into account the sharply lower global cost of energy. [82]

EQ asked us to pay particular attention to the effect of further increases in solar generation, both rooftop and large scale, on spot prices and therefore on wholesale energy costs. EQ considered that extreme negative spot prices are a risk to market participants and deserve as much attention as extreme high spot price events.[83]

Wholesale energy costs

Retailers incur wholesale energy costs when purchasing electricity from the NEM to meet the electricity demand of their customers. Retailers typically adopt a range of strategies to reduce their exposure to volatile wholesale electricity prices (spot price risk) when purchasing from the NEM, including pursuing hedging (financial), contractual and operational strategies.

We have estimated wholesale energy costs based on the ACIL Allen estimates, which reflect:

- a market hedging approach—to simulate expected spot prices that a retailer faces (having regard to the likely variation in demand profiles and generation and supply costs), and then estimate wholesale energy costs for a retailer that hedges spot price risk (through exchange-traded energy financial derivatives, i.e. ASX energy futures)
- market data up until early May—to take into account the most current information.[84]

This is broadly similar to the approach applied in previous years.

Analysis

Our decision is to determine wholesale energy costs based on ACIL Allen's advice, using a market hedging approach and up-to-date market data. To address stakeholders' concerns while still

[78] ACIL Allen's final report is available on our website.
[79] QCOSS, sub. 7, attachment, p. 9; EQ, sub. 4, attachment, p. 6.
[80] QEUN, sub. 20, pp. 13–20.
[81] QCOSS, sub. 18, attachment, p. 18.
[82] Canegrowers, sub. 11, p. 3.
[83] EQ, sub. 4, attachment, pp. 6–11, sub. 14, attachment, pp. 6–8.
[84] See Appendix E for a detailed description of ACIL Allen's market hedging approach.

meeting our final determination deadline, we have extended the energy data cut-off date (to 8 May 2020) to better reflect the impacts of covid-19, as well as other drivers, on the NEM.

We consider that this approach is transparent and likely to produce robust estimates of actual costs retailers incur when purchasing electricity from the NEM. This approach uses the latest available market data—including the uptake of rooftop solar PV, the latest peak demand and supply projections of the Australian Energy Market Operator (AEMO), and market participants' formal announcements on generation availability/operation.[85] This means that our estimates adequately take into account the likely variation in demand profiles and generation supply/costs (including fuel costs) within the NEM, while still meeting our final determination timeframe. The AEMC also endorsed a market hedging approach in its 2013 advice on best practice retail regulation.[86]

We also consider that this approach takes into account the potential impacts of covid-19 on the NEM, specifically through the incorporation of ASX contract data until May 2020. These contract prices reflect, to date, the market participants' views of the impacts of covid-19, as well as other drivers, on the NEM.

Further, to estimate wholesale energy costs, we have used a large number of simulations (i.e. 539 simulations), covering a wide range of the demand outcomes. These demand outcomes, though not driven by covid-19, are likely to adequately capture the potential demand variations due to covid-19 should they eventuate. The approach we adopted is consistent with the AER's methodology to determining the wholesale energy costs for its 2020–21 default market offer in south east Queensland.

QEUN emphasised the declining wholesale spot prices since covid-19 restrictions were introduced and compared wholesale prices with our energy cost estimates. However, wholesale prices do not reflect the costs that retailers would actually incur in practice when sourcing electricity from the NEM. To manage spot price volatility risk, retailers generally lock-in the price for an amount of electricity that they have to pay for in the future (for example, through the purchase of ASX contracts). In other words, retailers had already locked-in higher future electricity prices for a proportion of electricity to be supplied in 2020–21, before the more recent decline in wholesale and contract prices (that coincides with the covid-19 restrictions).

We agree with EQ that the continued uptake of rooftop solar PV and development of utility scale solar PV will likely increase the number of negative spot price outcomes during daylight hours. However, this phenomenon is not something new. In our earlier determinations, there were occasions when the simulated spot prices were below their corresponding trade-weighted contract prices (that a retailer locks-in). In this situation, retailers will be compensated for this negative price difference through ACIL Allen's hedge model as costs incurred while pursuing a hedging strategy using financial derivatives. We are satisfied that ACIL Allen's methodology adequately addresses EQ's concerns and captures the impacts of negative spot price outcomes during daylight hours.[87]

Compared to the estimates from last year, our estimates of wholesale energy costs have fallen for both small and large customer tariff classes,[88] reflecting the expected entry of renewable

[85] This is discussed further in Appendix E and addressed in chapter 3 of ACIL Allen’s final report.
[86] AEMC, *Advice on Best Practice Retail Price Regulation Methodology*, final report, September 2013.
[87] More details are available in chapter 3 of ACIL Allen's final report.
[88] As discussed in chapter 3, our final decision is to base notified prices for small customers on the costs of supply in SEQ, and for large customers on the costs of supply in Ergon east zone, transmission region one. This means the

investment in Queensland and other NEM regions, and a reduction in domestic gas prices.[89] Reductions in wholesale energy cost estimates for large customer tariffs are less significant—compared to small customer tariffs—due to the increasing proportion of electricity from the grid consumed during peak periods due to the uptake of rooftop solar PV in the Ergon area.

The change in wholesale energy costs for the controlled load tariffs largely reflects the volume and pattern of electricity consumption of these tariffs, which are controlled by Energex. Wholesale energy costs for tariff 31 are projected to decline less than those for tariff 33. This is because the majority of electricity consumed on tariff 31 occurs between 10pm and 2am and wholesale prices during these periods are not projected to decrease.

For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix E and ACIL Allen's final report.

Other energy costs and losses

Retailers incur other energy costs[90] and losses when purchasing electricity from the NEM, namely:

- Renewable Energy Target (RET) costs—associated with the purchase of certificates to meet the targets mandated under the RET[91]
- NEM management fees and ancillary services charges—the costs levied by AEMO to cover the cost of operating the NEM and services used to manage power system safety, security and reliability
- prudential capital costs—the costs of providing financial guarantees to AEMO and lodging initial margins with the ASX for futures contracts
- costs associated with energy losses—this is because retailers need to purchase more electricity than is demanded by customers to allow for losses that occur when electricity is transported (via transmission and distribution networks).

wholesale energy costs for small customers are based on the Energex net system and controlled load profiles, while for large customers, they are based on the Ergon net system load profile.

[89] The reduction in domestic gas prices is due to a slightly better global supply outlook, which has meant LNG exporters have made more supply available to the domestic market due to depressed international gas prices.

[90] Retailers may also incur costs associated with the Reliability and Emergency Reserve Trader (RERT) scheme. These charges are levied by AEMO to cover the costs of maintaining power system reliability and security using reserve contracts. For 2020–21, we estimated that no RERT costs will be incurred in Queensland. For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix E and ACIL Allen's final report.

[91] The RET, comprising 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.

Analysis

Our decision is to determine other energy costs and losses based on ACIL Allen's advice:

RET costs

- **Large-scale Renewable Energy Target (LRET) costs**—estimated using forward prices for large-scale generation certificates and renewable power percentage values derived from mandated LRET targets and estimates of electricity acquisitions
- **Small-scale Renewable Energy Scheme (SRES) costs**—estimated using the clearing house price for small-scale technology certificates and small-scale technology percentages that reflect the most recent expected uptake in small-scale renewable energy systems and the estimated carryover of surplus certificates from 2019

NEM fees and ancillary charges

- **NEM management fees**—estimated using AEMO's budget and fee projections
- **Ancillary services charges**—estimated using the average ancillary service payment observed over the preceding 52 weeks

Prudential costs

- **Prudential costs**—estimated using AEMO's prudential requirements and margin requirements for trading in the ASX futures market

Energy losses

- **Energy losses**—estimated by applying transmission and distribution loss factors published by AEMO, in a manner that aligned with AEMO's settlement process

We consider this approach is appropriate and is likely to produce the most reliable estimates of other energy costs incurred by retailers. The underlying methodologies are aligned with the way retailers incur these costs in practice, and use the latest market data, where available and appropriate, to enhance the accuracy of the estimates.

Compared to the estimates from last year:

- LRET costs have decreased by approximately 47 per cent ($4.39/MWh)—driven by a fall in the forward price of large-scale generation certificates due to a surge in renewable investment
- SRES costs have increased by approximately 28 per cent ($2.05/MWh)—driven by an increase in the number of small-scale technology certificates retailers are required to purchase, due to a higher uptake in small-scale renewable energy systems than previously estimated
- NEM management fees have increased by approximately 13 per cent ($0.08/MWh)—reflecting the higher costs that AEMO expects to incur when managing the NEM
- ancillary services charges have increased by 314 per cent ($1.16/MWh)—reflecting a surge in demand for ancillary services, including due to the Basslink interconnector outage in Tasmania, the planned outage of the Heywood to Mortlake line in Victoria, the islanding[92] of South Australia from the NEM and the extended power system separation between South Australia and Victoria.
- prudential costs have decreased by approximately 20 per cent ($0.43/MWh) for small customer tariffs and by about 5 per cent ($0.08/MWh) for large customer tariffs—reflecting lower expected price volatility in the NEM.

In summary, compared to the estimates from last year, our estimate of other energy costs:

- for small customer retail tariffs decreased by 7.7 per cent ($1.53/MWh)

[92] Islanding occurs when a jurisdiction's electricity network is disconnected from the rest of the NEM.

- for large customer retail tariffs decreased by 6.2 per cent ($1.18/MWh).

As part of this final determination, we have also updated our estimate of energy losses, based on AEMO's recently published 2020–21 loss factors. Compared to estimates last year, overall energy loss factors[93] have:

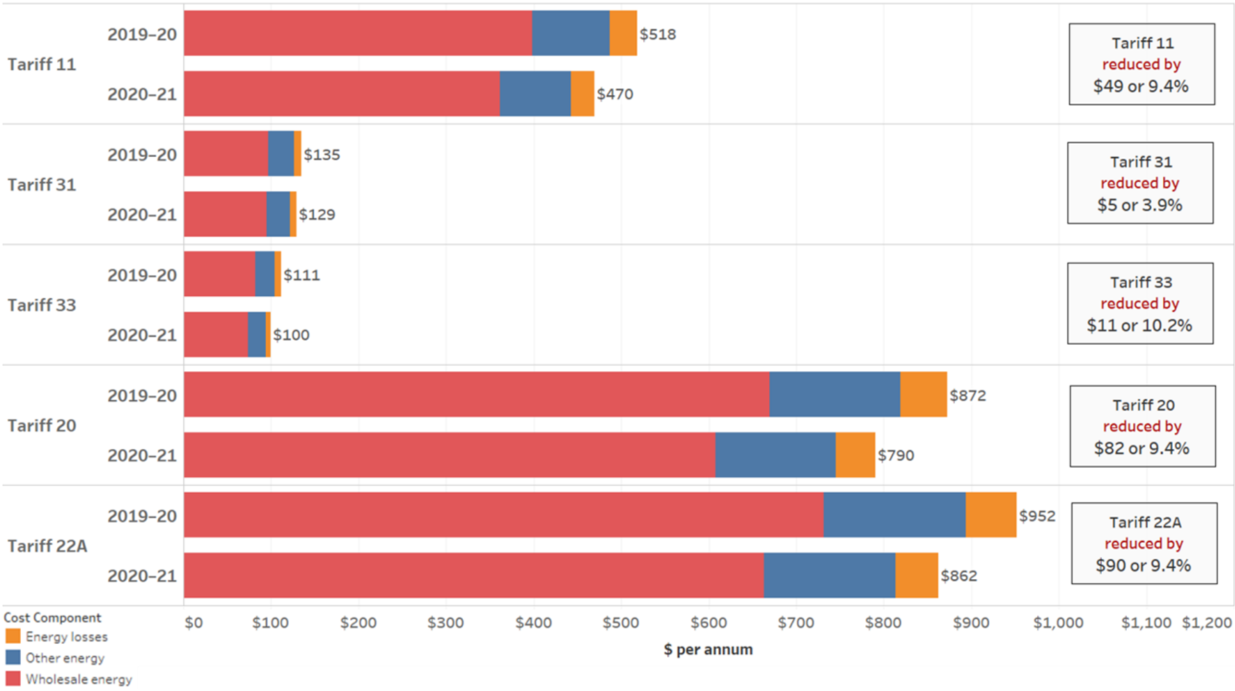
- decreased for small customer tariffs, reflecting a decrease in both transmission and distribution loss factors
- increased for large customer tariffs, reflecting an increase in transmission loss factors.

For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix E and ACIL Allen's final report.

Total energy costs included in final notified prices

The following charts show the overall energy costs included in our final notified prices, compared to last year's estimates—by tariff type for the typical small and large customers.

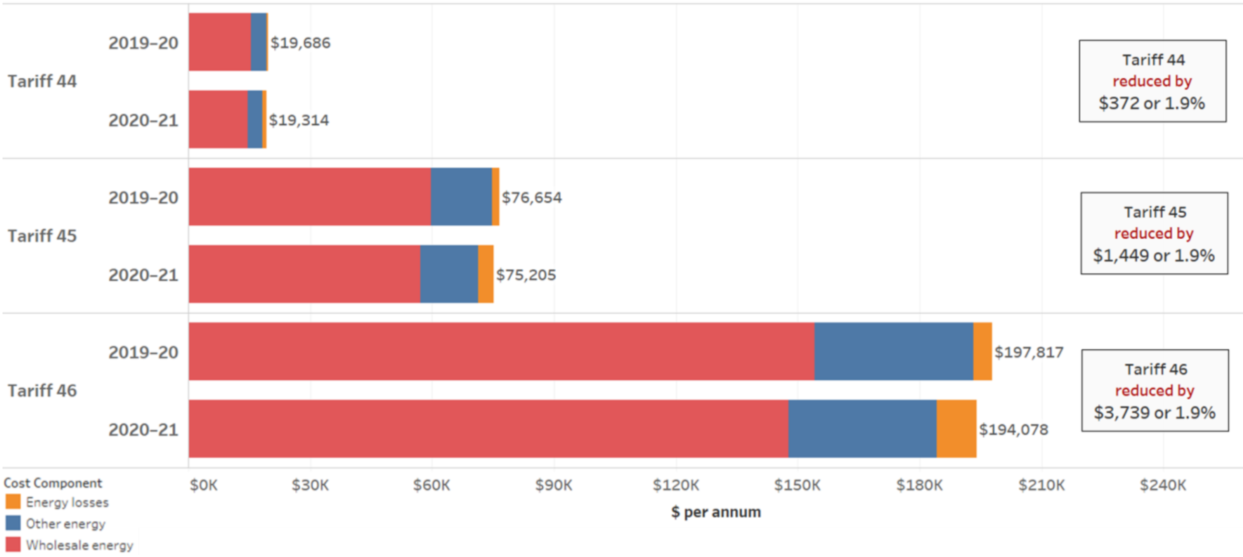
Figure 6 Energy costs—typical customers on small customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

[93] Total energy loss factors are the product of the distribution loss factor and the transmission loss factor.

Figure 7 Energy costs—typical customers on large customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

4.2.2 Retail costs

The costs of running a retail business include costs of servicing existing customers, acquiring new customers, and managing the risks associated with providing retail services. The delegation does not specify a particular approach to estimate retail costs, with one exception—consistent with previous determinations, we are to exclude residential and small business customer metering costs.[94]

We last undertook a comprehensive review of retail costs as part of the 2016–17 price determination. That assessment used a combination of bottom-up and benchmarking methods, using information from public sources (including retail market offers) and confidential information from retailers.[95] In determinations since then, we updated the 2016–17 cost estimates in the following way:

- the fixed cost allowances were adjusted for the forecast change in the CPI (to maintain the allowances in real terms)
- the variable retail cost percentage allocators were maintained at 2016–17 levels.[96]

Stakeholder submissions

In light of the market environment and review timeframe, most stakeholders did not object to us using the same approach to set retail costs this year as for previous determinations[97], but were keen for this approach to be updated in future:

---

[94] Consistent with previous determinations, we separated the non-AER regulated metering costs for large customers from retail costs, and estimated metering charges separately (see section 5.6).
[95] More information on how we calculated the 2016–17 retail cost allowance can be found in our 2016–17 final determination, which is available on our website.
[96] To calculate the variable retail cost percentage allocators in the 2016–17 determination, we calculated the variable retail cost component as a percentage of total variable costs (excluding variable retail costs).
[97] QCOSS, sub. 18, attachment, p. 14; EQ, sub. 14, p. 8; COTA, sub. 12, p. 1; Queensland Consumers Association, sub. 19, p. 1.

- QCOSS said updates to the existing retail cost allowance should be undertaken as a matter of urgency and 'customers must not bear any of the cost-burden of the reforms themselves including any unreasonable transitional costs'.[98] Further, both Queensland Consumers' Association and QCOSS said that additional efficiencies had been achieved since our last comprehensive review of retail costs, and called for the retail cost estimates to be updated to incorporate these efficiencies.[99]
- On the other hand, EQ said there is a need for greater acknowledgement of increasing regulatory compliance costs that are material and should be appropriately accounted for in retailer costs, including costs associated with various regulatory and policy reforms, such as new hardship requirements, new life-support obligations, new market reform initiatives and additional compliance obligations.[100]

Canegrowers was concerned that including jurisdictional charges in variable retail costs would 'deliver a small windfall gain to retailers at the expense of consumers' and said they should be removed from the cost base on which the retail margin is calculated.[101]

In regard to updating the retail cost estimates in future:

- COTA said it is prudent to carry out a full bottom-up review of retail costs every five years at a minimum and urged the QCA to revisit this exercise in the next price review.[102]
- QCOSS said the time available after the QCA receives its annual delegation was not sufficient and a separate review should be conducted (outside of the usual notified price process) to determine new retail cost benchmarks. It asked that we clarify and commit to when and how this can occur.[103]
- Stakeholders were also keen to understand what impacts covid-19 would have on retail costs and operations, with EQ noting it is continuing to monitor this situation.[104]

Analysis and final decision

We consider there may be merit in establishing new retail cost allowances reflecting up-to-date information. However, in the current uncertain market environment, we are concerned the information we would need to rely on (e.g. retail market offers and cost data), would not be reliable. The following market reforms and environmental factors are likely to impact our assessment:

- Network tariff reforms—the potential introduction of more complex network tariff structures from 1 July 2020[105] is likely to increase costs, but the magnitude of the increase is unknown. If retailers decide to align retail tariff structures with network tariff structures, they may incur additional costs to upgrade systems and educate customers. If retailers instead decide to moderate customer impacts by maintaining current retail tariff structures, they would likely be taking on greater risk due to the misalignment of network and retail tariff structures.

98 QCOSS, sub. 7, p. 2, sub. 18, attachment, p. 14.
99 QCOSS, sub. 7, attachment, pp. 10–11; Queensland Consumers' Association, sub. 8, p. 2.
100 EQ, sub. 4, attachment, pp. 12–13, sub. 14, attachment, p. 8.
101 Canegrowers, sub. 11, p. 4.
102 COTA, sub. 12, p. 1.
103 QCOSS, sub. 18, p. 2; Queensland Consumer's Association, sub. 19, p. 1.
104 EQ, sub. 14, attachment, p. 8.
105 See chapter 3 for more details.

- Introduction of the DMO—current market prices are unlikely to be a reliable basis for estimating retail costs. The retail market is still adjusting to the introduction of the DMO in mid-2019. We note the AER's view that:

  > The current evidence suggests the introduction of the DMO has reduced high priced standing offers while maintaining the availability of low priced market offers.[106]

  But the AER also notes that:

  > [It is] too early to draw strong conclusions about the impact of the DMO. This is because, in a dynamic market we expect electricity retailers will respond to competitors by adapting their offers and pricing and significant changes will likely become apparent over a longer time period ...[107]

  We expect the retail market will continue to adjust over the coming year in response to the DMO2 (approved by the AER in May 2020 to apply from mid-2020). Also, given the DMO is likely to be a consistent feature of the electricity market in future, ongoing market adjustments can be expected.

- Potential impacts of covid-19—since our draft determination, the coronavirus pandemic has significantly impacted every facet of the economy. At this time, it is unclear what the effects may be on retail costs. It is likely that any potential impacts may be ongoing (and unable to be fully quantified) for some months.

Stakeholders did not comment substantively on covid-19 impacts during our review, but did raise concerns in the AER's DMO process on this matter.[108] For example, submissions to the AER pointed to the potential for retail costs to increase as a result of bad debts, increased resourcing costs (due to staff working from home), closure of international call centres and increased customer call volumes. However, no adjustments were made to costs. The AER explained that:

> the current level of uncertainty about COVID-19 and limited information makes it difficult for us to forecast the cost impacts.[109]

Given the uncertainty identified, we consider updating our retail cost benchmark this year is unlikely to produce more reliable and robust cost estimates than if we continued to use our current approach of updating 2016–17 cost estimates. Also, we note this approach is also broadly consistent with that applied by the AER in its recent final determination of the DMO for 2020–21 where, after assessing potential step changes in retail costs, the AER considered no specific adjustments were necessary, and made a final determination to adjust the previous year's retail cost estimate to reflect forecast changes in the CPI.[110]

Consistent with our previous practice, we consider it would not be appropriate to remove the SBS costs from the cost base used to calculate the variable retail costs, as suggested by Canegrowers. This is because the jurisdictional scheme charges (including the SBS costs) form a component of network charges (regulated by the AER), which distributors recover from retailers (see section 3.3.1).

Accordingly, our final position is to maintain our current approach of updating the 2016–17 retail cost estimates. However, we will consider whether it is appropriate to revisit this approach in the future. We note it would also be possible to conduct a separate review process (as suggested by

[106] AER, *Default Market Offer Prices 2020–21*, draft determination, February 2020, p. 12.
[107] AER, *Default Market Offer Prices 2020–21*, draft determination, February 2020, p. 25.
[108] As part of the additional consultation in the AER's DMO2 process on covid-19 (see the AER's website at https://www.aer.gov.au).
[109] AER, *Default Market Offer Prices 2020–21*, final determination, April 2020, p. 21.
[110] AER, *Default Market Offer Prices 2020–21*, final determination, April 2020, p. 48.

some stakeholders) given the relatively short timeframes of the annual price reviews. However, a separate direction from the government would be required to initiate such a review.

Residential and small business customers (small customers)

For small customer tariffs, we:

- adjusted the 2019–20 fixed retail cost allowances by the Reserve Bank of Australia's (RBA’s) forecast of the change in the CPI for 2020–21[111]—to maintain the fixed component in real terms
- maintained the variable retail cost allocators at 11.27 per cent for residential customers and 12.80 per cent for small business customers—the same levels established in the 2016–17 price determination.[112]

Large customers

For large customer tariffs, we adjusted the 2019–20 fixed retail cost allowances by the RBA’s forecast change in the CPI, and maintained variable retail cost allocators at 6.0445 per cent (the same level established in the 2016–17 price determination).

Total retail costs included in notified prices

Retail costs are generally decreasing, compared to 2019–20. This is primarily due to a reduction in variable network and energy costs, which has decreased the value of variable retail costs for most tariffs. The reduction, however, is tempered by the increase in the fixed retail cost component.

The following charts compare the retail cost allowances included in the final notified prices with the 2019–20 allowances. The comparison is by tariff type for typical small and large customers.[113] We note actual costs will vary for individual customers with different levels of electricity usage.

[111] The RBA revised its forecast on 8 May 2020, now estimating a change in the CPI of –1 per cent for the period ending June 2020 and 2.75 per cent for the period ending June 2021. We took an average of these forecasts to derive a value of 0.875 per cent for 2020–21. See RBA, *Statement on Monetary Policy—May 2020*, May 2020, p. 89.

[112] To calculate the variable retail cost percentage allocators in the 2016–17 determination, we calculated the variable retail cost component as a percentage of total variable costs (excluding variable retail costs). More information on how we calculated the 2016–17 retail cost allowance can be found in our 2016–17 final determination, which is available on our website.

[113] Typical customer consumption data was provided by Ergon Retail (see Appendix H).

Figure 8 Retail costs—typical customers on small customer tariffs (GST incl.)

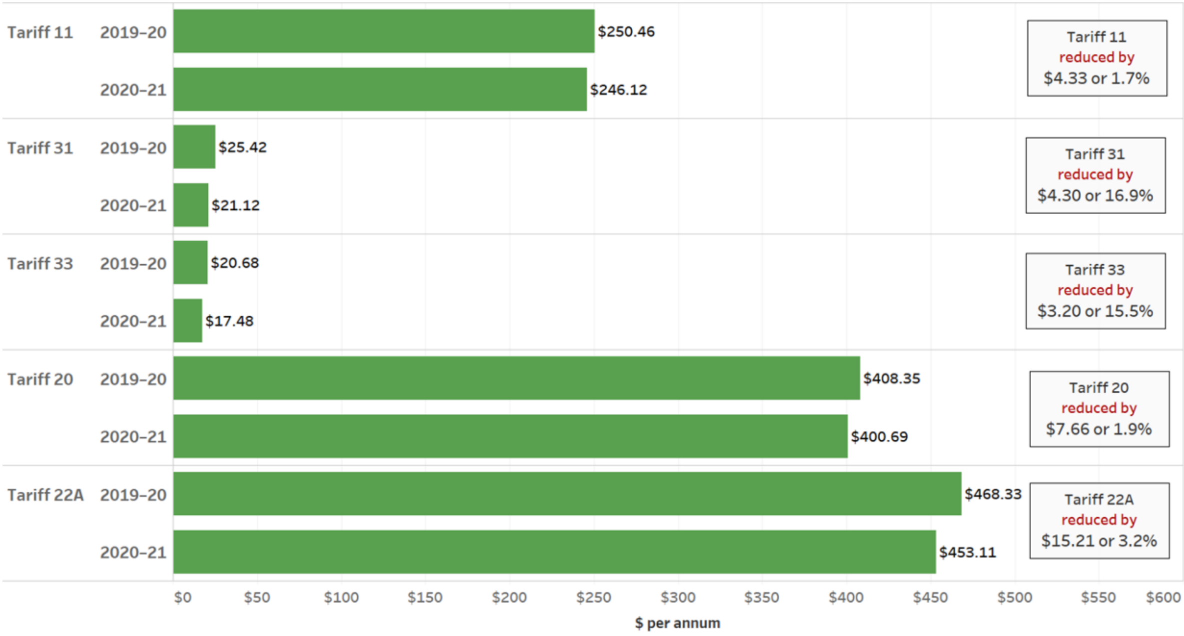
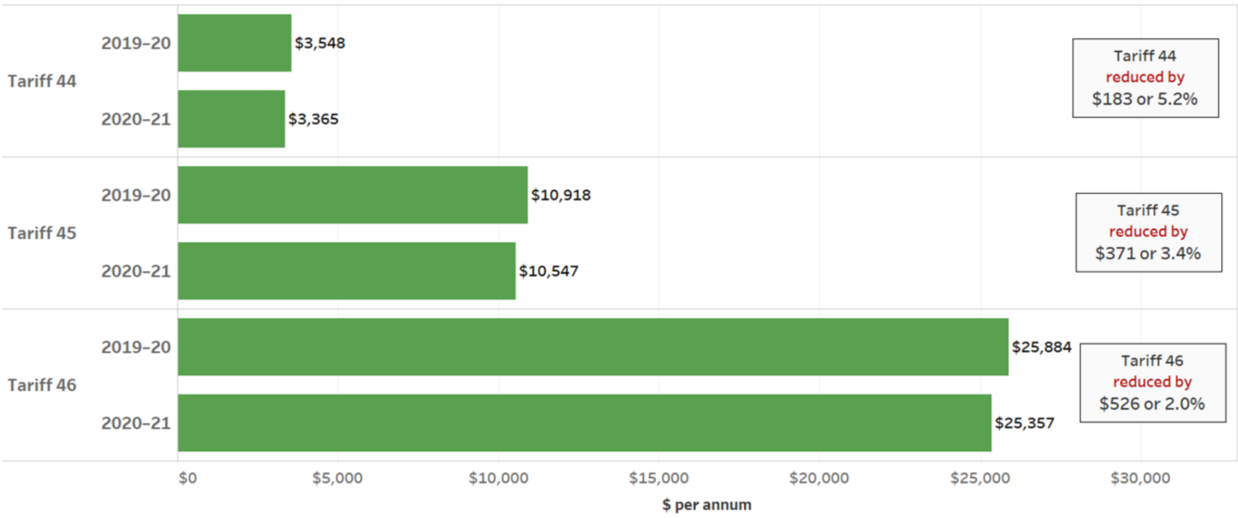


Figure 9 Retail costs—typical customers on large customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

5 OTHER COSTS AND PRICING ISSUES

This chapter sets out the other costs and pricing issues relevant for this determination, including any adjustments we need to consider when setting notified prices. Many of these matters are identified in the delegation, which we must consider when setting notified prices.

The following matters are discussed:

- standing offer adjustment for small customers
- headroom for large customers
- cost pass-through
- obsolete tariffs
- enabling the provision of additional retail services
- large customer metering costs
- additional issues raised by stakeholders.

5.1 Standing offer adjustment—small customers

The terms of the delegation require us to consider incorporating a standing offer adjustment amount into notified prices for residential and small business customers, taking the following matters into consideration:

- basis for the adjustment—the adjustment should reflect the more favourable terms and conditions of standard contracts relative to market contracts
- level of the adjustment—the level included in previous determinations (i.e. 5 per cent of total costs) should be maintained, as it appropriately reflects the additional value of more favourable standard contract terms and conditions, but the resulting electricity bill should not exceed the equivalent default market offer (DMO) reference bill.

Stakeholder submissions

Many stakeholders said electricity prices should not include a standing offer adjustment. Their reasons included:

- regional customers pay more for their electricity because they do not have access to market contract prices, which is inconsistent with the UTP
- there is doubt about whether standing contracts actually do provide significant benefits and protections (and therefore value) for consumers compared to market contracts, including whether the value of these terms equates to the $50 to $60 per annum included in pricing.[114]

Therefore, many stakeholders said the adjustment value should ideally be zero, but no more than 5 per cent.[115] They also suggested that we should not simply carry forward the 5 per cent value this year, but that we should undertake and publish more robust analysis of the value customers

[114] COTA, sub. 12, p. 2.
[115] QCOSS, sub. 7, p. 2 and attachment, pp. 12–15; Queensland Consumers' Association, sub. 8, p. 2.

place on having standard terms and conditions, or provide a credible quantification of the proposed adjustment, for stakeholder comment.[116] Queensland Consumers' Association said the review of the standing offer adjustment should be public and conducted separate to, and before the start of, the next price-setting process.[117]

On the other hand, EQ said market contracts are discounted and do not contain the same terms and conditions as standard retail contracts, which is 'evidence that these contractual consumer protection provisions offer value to electricity customers'.[118]

Consumer groups supported the adjustment being reduced to ensure notified prices do not exceed the equivalent DMO for SEQ set by the AER.[119] QCOSS said stakeholders should have been provided with an opportunity to review and comment on the methodology we would use to make any such adjustment prior to the final determination. This would have allowed stakeholders to identify any potential issues before the final notified prices were set.[120]

Analysis and final position

Under the delegation, we must consider basing the standing offer adjustment on the value of more favourable standard contract terms and conditions relative to market contracts and to include an adjustment that is similar to the adjustment in previous determinations (i.e. 5 per cent of total costs).

We do consider standard contracts typically provide more favourable terms and conditions than market contracts. These benefits include simpler pricing, access to paper bills at no extra cost, better payment terms (which can include bill smoothing) and ongoing certainty of terms (i.e. retailers cannot change terms or impose restrictions, as they can under market contracts).

In the 2019–20 determination, we considered the fees and charges a SEQ customer would likely incur on a market contract (such as access to paper bills and the use of credit/debit card) that were potentially provided to customers on standard contracts as benefits due to the more favourable terms and conditions. The analysis indicated that typical residential customers in SEQ can pay up to 9.5 per cent of their annual bill to enjoy these benefits. Typical small business customers can pay up to 7.4 per cent of their annual bill to enjoy these benefits.

Despite the limitations inherent in that analysis, it provided a useful indication of the potential maximum amount customers in SEQ would need to pay to enjoy the benefits of more favourable terms and conditions. As such, a reasonable adjustment to reflect the more favourable terms and conditions is likely to be less than 9.5 per cent for residential customers and 7.4 per cent for small business customers.

We have previously acknowledged the difficulty of appropriately quantifying the value of these additional benefits. Nevertheless, taking into account the analysis and conclusions from last year[121], and the requirement in the delegation to consider applying a similar adjustment to previous determinations, we consider maintaining the adjustment at 5 per cent of total costs is reasonable.

[116] QCOSS, sub. 7, p. 2 and attachment, pp. 12–15; COTA, sub. 12, p. 2.
[117] Queensland Consumers Association, sub. 19, p. 1.
[118] EQ, sub. 4, attachment, p. 13.
[119] QCOSS, sub. 7, p. 1 and attachment, p. 15, sub. 18, p. 2 and attachment, pp. 16–18; Queensland Consumers' Association, sub. 8, p. 2.
[120] QCOSS, sub. 18, attachment, p. 17.
[121] QCA, *Regulated retail electricity prices for 2019–20*, final determination, May 2019, chapter 6.

We acknowledge some stakeholders would prefer no standing offer adjustment at all be included in notified prices. However, the inclusion of a 5 per cent adjustment (or lower adjustment if the DMO cap applies) brings notified prices closer to the actual costs of supply, which is a factor the Electricity Act requires us to consider when determining notified prices.[122]

Reducing the adjustment

Consistent with the delegation, we assessed whether the 5 per cent standing offer adjustment needs to be reduced for small customers—that is, in the case where the resulting notified price bill (including a 5 per cent standing offer adjustment) would exceed the equivalent DMO reference bill in SEQ.

In order to do this, we followed a two-step process:

(1) We assessed the components of the DMO reference bill to ensure any comparisons made with the relevant notified price customer bill were made on a like-for-like basis. This included taking account of:

- metering costs, which are included in the DMO reference bill but not our notified prices
- GST, which is included in the DMO reference bill, but is not included in our notified prices
- consumption levels, which are different for the DMO reference bill than what we use to calculate our notified price bill impacts.

(2) We then compared each of the DMO reference bills with the relevant notified price customer bills (with a standing offer adjustment of 5 per cent).

Based on the comparisons (step 2 above), we found one notified price bill—for the flat rate residential tariff (tariff 11)—exceeded the equivalent DMO reference bill.

Accordingly, in order to bring the tariff 11 notified price bill down to the equivalent DMO reference bill, we have reduced the level of the standing offer adjustment for tariff 11 to approximately 2.2 per cent (from 5 per cent).

Appendix J sets out further detail, including the process and bill comparisons described above we used to inform this decision.

5.2 Competition and headroom—large customers

In making our determination we are required to have regard to, among other things, the effect of it on competition in the Queensland retail electricity market.[123] Since the 2012–13 determination, we have included a headroom allowance of five per cent of total costs in notified prices for large and very large customers. The purpose of including headroom was to promote retail competition in this market segment by:

- incentivising retailers to enter the market and compete for customers

[122] See s. 90(5) of the Electricity Act.
[123] See s. 90(5) of the Electricity Act.

- encouraging customers to move off notified prices and seek out more attractive offers in the competitive market.[124]

A well-functioning competitive market is expected to deliver lower prices, innovative products and more choice for consumers than is the case where services are provided by a small number of firms with market power. As competition becomes more effective, there is generally less need for price regulation to protect consumers from the exercise of retailer market power and the deregulation of prices needs to be considered to ensure the long term interests of consumers.

Stakeholder submissions

Cotton Australia[125] and QEUN[126] did not support including a headroom allowance in notified prices. Cotton Australia said the concept is flawed and is akin to a retailer increasing prices one day, so it can offer a discount the next. Also, it said there is no evidence competition has developed from its application and, as such, the inclusion of headroom is just a windfall gain. QEUN said prices should not be inflated to promote non-existent retail competition.

EQ noted the headroom adjustment has enabled the development of a competitive market in some customer segments, and that the rationale for continued use of an appropriate headroom allowance to stimulate competition remains sound.[127]

Analysis and position

The long-standing approach of including a headroom allowance may have promoted a degree of competition in those areas where notified prices closely reflect the actual costs of supply—that is, the Ergon east pricing zone, and particularly transmission region one (which we refer to as east zone one). Based on the most recent data from EQ, a significant proportion of large and very large customers in east zone one are on a market contract—50 per cent of large customers and 77 per cent of very large customers.[6] We have identified market features that may not support the further development of competition:

- Switching risk—once a large/very large customer accepts a market contract, they can no longer access notified prices. This is likely to discourage customers from accepting a market offer in the first place.
- Continued access to below-cost tariffs—some large/very large customers may be accessing tariffs that do not reflect the actual costs of supplying them. These include:
  - obsolete tariffs, although most of these tariffs are due to be removed next year (see section 5.4)
  - tariff 53, which is the standard tariff available to very large customers (see section 3.3.3).

  In instances where customers are on tariffs that are below cost, retailers will have limited ability to offer those customers a better deal on a market contract.

That said, the continuation of price regulation more generally, where competition is already well established, may do more harm than good. Regulated prices are based on imperfect cost information and are not flexible enough to accommodate differences in individual customer

[124] The inclusion of headroom to promote competition is consistent with the AEMC's advice on best practice retail regulation (AEMC, *Advice on Best Practice Retail Price Regulation Methodology*, final report, September 2013) and is consistent with the past practice of other regulators, including IPART.
[125] Cotton Australia, sub. 3, pp. 2, 6, sub. 13, p. 3.
[126] QEUN, sub. 20, pp. 23–25.
[127] EQ, sub. 4, attachment, p. 13.

preferences or to adjust to changing market conditions. There is also a risk that the limited regulatory tools available to promote competition (like headroom) instead produce regulated prices that serve as a coordination device among retailers, potentially resulting in higher market prices than if price regulation were removed.[128]

We have no compelling evidence before us that that headroom is an effective means of promoting competition, particularly given the issues we have identified above. We have therefore decided against including a headroom allowance in notified prices for large and very large customers.

5.3 Cost pass-through mechanism

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

QCOSS did not support this approach and considered that the costs of supply in 2019–20 are not relevant to the costs of supply in 2020–21, with it noting the AER's DMO calculations do not allow under-recovery of costs from one year to be added to the next year's tariffs.[129]

However, to continue to align notified prices with the UTP, we consider a cost pass-through mechanism is necessary to account for the under- or over-recovery of costs beyond the control of regulated entities. In previous determinations, we have provided a cost pass-through for SRES and we have decided to do the same for this review.

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

5.3.1 SRES cost pass-through

Retailers incur SRES costs based on the number of certificates that they are required to purchase and surrender to the Clean Energy Regulator (CER). The CER determines these SRES liabilities for each calendar year, but notified prices are determined for each financial year.

Generally, at the time of our final determination for notified prices, only the SRES liabilities for the first half of the financial year are known, while liabilities for the second half are based on the forecasts from the CER. The CER typically determines the final SRES liabilities for the second half of the financial year about 9 months after our final determination.

Such an arrangement can lead to an over- or under-recovery SRES costs if there are discrepancies between the CER's forecast and its final determination of the SRES liabilities. To account for the over- or under-recovery SRES costs, we have decided to apply a cost pass-through mechanism.

5.3.2 Analysis and final decision

The CER has updated the SRES liabilities for 2020 to reflect the most recent developments in the uptake of small-scale renewable energy systems. This means that retailers will be required to

[128] Yarrow, G, *Report on the impact of maintaining price regulation*, Regulatory Policy Institute, Oxford, UK, January 2008, p. 71.
[129] QCOSS, sub. 18, attachment, p. 18.

purchase and surrender more certificates to CER than initially estimated—leading to an under-recovery of SRES costs for 2019–20.

Using the final SRES liabilities for 2020, we estimated that these under-recovered SRES costs will increase usage charges for all retail tariffs. For a more detailed explanation on how the SRES cost pass-through was estimated, refer to our technical appendix.

Depending on the regulatory framework for future price determinations and whether changes are made to the UTP, 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.

5.4 Obsolete tariffs

5.4.1 Scheduled phase-out date

After the 2019–20 determination, the government extended the phase-out dates for the majority of obsolete tariffs—that is, tariffs 20 (large), 21, 22 (small and large), 37, 62, 65, and 66—by one year to 1 July 2021.[130] This was in recognition of the challenges that some customers faced when adjusting to standard tariffs. This year, the delegation requires us to consider maintaining the current phase-out date for obsolete tariffs.

Stakeholder submissions

Cotton Australia raised concerns about the network tariff reforms and the uncertainty around what tariffs would be available, noting this year was meant to be a period where users would have the choice of existing and new tariffs to review before the loss of access to obsolete tariffs.[131] Similarly, QFF raised concerns in light of uncertainty associated with alternative tariff options available after the phase-out date, arguing to extend timeframes for tariffs 62, 65 and 66, regardless of when new alternative tariffs are introduced, to allow users time to assess the alternative tariffs.[132]

Many stakeholders were keen to see the tariffs that will be available to customers on obsolete tariffs once they expire, given the concerns customers have with the existing tariffs. Customers could then also assess the best option for their business.[133]

QFF and Cotton Australia both called for the extension of the determination process to facilitate the implementation of replacement tariffs for tariff 62, 65 and 66, and the introduction of primary interruptible supply tariffs 33 and 34 by October 2020. The QFF contended this was vital to give regional consumers an opportunity to compare the cost and viability of new and old tariff options.[134]

Analysis and final position

Consistent with the delegation, we are maintaining the existing scheduled phase-out date for obsolete tariffs. Customers have had eight years to prepare to move to standard tariff prices and structures. We encourage customers to engage with Ergon Retail as soon as possible to best manage the transition away from obsolete tariffs.

[130] This phase-out date is applicable to all obsolete tariffs, except tariffs 47 and 48 (which are scheduled to expire on 30 June 2022).
[131] Cotton Australia, sub. 2, pp. 2, 6.
[132] QFF, sub. 21, p. 3.
[133] Cotton Australia, sub. 13, p. 2; Kalamia, sub. 15, p. 2.
[134] Cotton Australia, sub. 13, p. 2; QFF, sub. 21, p. 4.

We note stakeholders were keen to see notified prices that reflect the proposed new transitional time-of-use network tariffs that EQ plans to introduce—which mirror the structure of obsolete tariffs 62, 65 and 66.[135] As these network tariffs are not scheduled to apply until 1 July 2021, the introduction of retail tariffs based on these tariffs is beyond the remit of this review.

Stakeholders also noted customers on obsolete tariffs were keen to see new load control tariffs introduced, based on EQ's new load control network tariffs. The reasons for not introducing new load control retail tariffs as part of this determination are discussed in section 3.2.3.

5.4.2 Price adjustments to obsolete tariffs

Unlike other tariffs, obsolete tariffs are not determined using the N+R approach. In previous determinations, we escalated prices for obsolete tariffs when prices for the alternative standard tariff increased.[136] Where standard tariff prices decreased, we maintained obsolete tariffs at their existing price levels.

Stakeholder submissions

A number of stakeholders said we should pass through reductions in electricity costs to customers on obsolete tariffs. Cotton Australia said this would give these customers relief during periods of falling prices.[137] Kalamia noted standard small business tariff usage costs have decreased, while transitional tariffs have remained frozen, which further disadvantaged rural customers.[138] Similarly, QFF was disappointed that cost reductions may not be passed on to farmers on irrigation tariffs and other business tariffs.[139]

Analysis and final position

As notified prices for standard tariffs are decreasing this year, we decided to maintain obsolete tariffs at existing price levels in 2020–21.

While we considered stakeholder views, including the potential benefits to some customers if obsolete tariffs were reduced, we remain of the view that our approach to freeze obsolete tariffs at existing price levels is reasonable.

In previous determinations, our approach has been to escalate obsolete tariff prices if standard tariff prices increased and leave obsolete tariff prices unchanged (or frozen) if standard tariff prices decreased. This approach reduces the price difference between obsolete tariffs and standard tariffs, as well as the relative cost advantage customers on obsolete tariffs have as a result of lower prices, relative to customers on standard tariffs.[140]

Based on analysis from Ergon Retail, some customers may be better off moving from obsolete to standard tariffs.[141] Reducing obsolete tariff charges one year prior to their phase-out would hamper efforts to encourage these customers to engage with Ergon Retail and shift to standard tariffs before 1 July 2021.

---

[135] The proposed access eligibility criteria for these network tariffs are available in Ergon Distribution's Tariff Structure Statement. It stated that in order to be eligible for the new tariffs, customers must have accessed tariff 62, 65 or 66 at some point from 1 July 2017 to 30 June 2020 (see Ergon Energy, *Tariff Structure Statement 2020–25*, May 2020, p. 24).

[136] Refer to our 2019–20 final determination on regulated retail electricity prices for a detailed summary of our considerations in determining an appropriate escalation factor for obsolete and transitional tariff charges.

[137] Cotton Australia, sub. 3, p. 7.

[138] Kalamia, sub. 5, p. 2.

[139] QFF, sub. 9, p. 2.

[140] QCA, *Regulated retail electricity prices for 2019–20*, final determination, May 2019, pp. 70–74.

[141] See Appendix G.

Other customers may not be better off moving from obsolete to standard tariffs. However, they are paying lower prices than the already subsidised standard tariff prices, so we do not consider further price relief is appropriate, as suggested by stakeholders. A further reduction would also increase the difference between obsolete tariff prices and standard tariff prices, which would exacerbate the impact of moving to standard tariff prices in 2021.

To best manage the transition away from obsolete tariffs, customers are encouraged to engage with Ergon Retail as soon as possible.

5.5 Enabling the provision of additional retail services

The delegation requires us to consider enabling retailers to offer standard contract customers the following services:

- the purchase of electricity from renewable or environmentally friendly sources (but only if certain conditions are met)
- participating in Ergon Retail's EasyPay Reward scheme, which entitles customers to payment credits if they meet certain conditions.[142]

We consider there is no reason to refuse to enable the provision of the above services, noting the programs do not affect customers' rights to standard contract terms and conditions or notified prices. As such, the available schemes have been incorporated into the gazette notice (see Appendix K).

5.6 Large customer metering costs

Consistent with previous determinations, we have separated the large customer metering costs for advanced digital meters from retail costs and estimated these metering charges separately.

Also consistent with previous determinations, we have estimated metering charges based on the latest confidential data provided by retailers. We averaged this data to produce cost estimates for each large customer type.

Overall, metering costs (based on the latest data) indicate a decrease in costs for connection asset customers and an increase in costs for standard asset customers and individually calculated customers.

The metering charges for large customers are set out in chapter 6.

5.7 Additional issues raised by stakeholders

The table responds to additional issues raised in submissions, which are not addressed elsewhere in this determination.

Table 1 Additional issues raised in stakeholder submissions

Stakeholder comment	***Our response***
Several stakeholders said there was a need to develop new tariffs for agricultural and related industries: • The Australian Sugar Milling Council suggested developing a new grower tariff that encourages	In accordance with the delegation, we are required to consider setting notified prices using an N+R approach. The question of whether it is appropriate to develop new agricultural-oriented tariffs is a

[142] This scheme was closed off to new customers on 31 December 2019 and will end on 30 September 2020.

Stakeholder comment	***Our response***
energy usage during the daytime off-peak period and takes advantage of falling solar input costs.[143] • Cotton Australia said we should work with the networks to ensure cotton gins and other similar industries have access to more flexible demand-based tariffs, including those that allow different tariffs for the ginning and maintenance seasons (given the different energy use during these periods). It also highlighted the impacts fixed costs can have on highly seasonal industries, such as cotton ginning.[144] • QFF said it is paramount that producers have access to tariffs that are not only cost-effective, but also reflect their usage, and are flexible to accommodate their business's varying usage. [145]	matter for EQ (and its distribution businesses) and the AER to determine at the network level.
QCOSS said we should consider our role in the future and how it must shift to support the transition to a future electricity grid, including relating to decarbonisation.[146]	We perform our role in accordance with the requirements of the Electricity Act and the terms of our delegation. While we note QCOSS's comments, these broader policy issues are outside the scope of our current determination process and are matters for the Queensland Government.
QFF raised issues around the treatment of electricity costs in our rural irrigation price review and said electricity prices should not be determined in isolation from irrigation water prices.[147]	The timing and nature of the QCA's role in relation to electricity and irrigation water prices are determined by legislation and the terms of the relevant ministerial referral/delegation. The QCA does not have a deterministic role in respect of irrigation water prices. We can be directed to investigate and make recommendations about these prices via a ministerial referral in accordance with Part 3 of the *Queensland Competition Authority Act 1997*. We considered those specific matters raised by QFF as part of our rural irrigation price review (2020–24) and made our recommendations to the relevant Minister. Our role in determining regional electricity prices is governed by the Electricity Act and the terms of our ministerial delegation.
National Seniors Australia (NSA) expressed concerns about the network tariff structures proposed by EQ.[148]	We note NSA has raised with the AER several issues associated with the network tariff structures proposed by EQ. These are matters for the AER to consider as part of its network determinations for Energex and Ergon Distribution.

[143] ASMC, sub. 1, p. 2.
[144] Cotton Australia, sub. 3, pp. 4–5, sub. 13, p. 2.
[145] QFF, sub. 9, p. 3.
[146] QCOSS, sub. 7, p. 2.
[147] QFF, sub. 9, p. 3, sub. 21, pp. 3–4.
[148] NSA, sub. 6, p. 1.

Stakeholder comment	***Our response***
Canegrowers made comments in relation to Energex and Ergon Distribution's network revenue and tariff proposal.[149]	While we note the matters raised by Canegrowers, these are matters for the AER to determine as part of its network determinations for Energex and Ergon Distribution.
Stakeholders raised concerns about the transition from obsolete tariffs: • Cotton Australia raised concerns about the financial impact and appropriateness of transitioning from the obsolete farming and irrigation tariffs to the demand-based tariffs for large irrigators.[150] • Kalamia said before transitional tariffs expire, alternatives must be developed to meet the specific requirements for agricultural irrigation.[151]	In accordance with the delegation, we are required to consider setting notified prices using an N+R approach. Customers on obsolete tariffs have had an eight-year transition period in which to assess tariff options once obsolete tariffs expire. This was originally put in place to alleviate price shocks and provide customers an opportunity to assess options and engage with Ergon Retail on what option may best suit their needs. The question of the appropriateness of demand-based network tariffs for large irrigators is a matter for EQ (and its distribution businesses) and the AER to determine at the network level.
EQ proposed the extension of retail discretion rules on drought revocation for drought-affected sites, such as allowing sites on tariff 66 to move to tariff 62 or 65.[152]	The arrangements for access to obsolete tariffs is a matter of government policy. We encourage EQ to consult the government on this matter.
QFF was of the view the restrictions on access to obsolete tariffs hampered the efforts of customers to move to alternative tariffs due to the 'fear of non-reversion and lack of trust in the tariff identification process'.[153]	The non-reversion arrangements are a matter of government policy. We encourage Ergon Retail and customers on these tariffs to engage with each other to identify suitable alternative tariffs.
QCOSS made comments on the QCA's consultation process for this review. In particular, it suggested future stakeholder engagement could be improved by: • scheduling workshops much sooner after the release of the draft determination so that stakeholders can genuinely be helped by the workshops to provide submissions • changing the format of workshops to allow 'deep dives' on key issues • having workshops with QCA board members or staff present that have a sufficient degree of autonomy to provide meaningful exploration of viewpoints and options that goes beyond describing the specific content of the QCA's draft determination • changing the annual timetable to avoid scheduling consultation over the December / January holiday period.[154]	We note the comments about our consultation process for the review, including the stakeholder workshops on the draft determination. Unfortunately, our usual practice of holding a series of stakeholder workshops in regional locations and in Brisbane was impacted by covid-19. This required us to hold workshops remotely and also resulted in delays to their scheduling. We appreciate the participation of stakeholders at these workshops, and stakeholder submissions made at each stage of our consultation process. Stakeholder consultation is an important part of our decision-making processes and we will consider improvements that can be made for future processes.

[149] Canegrowers, sub. 2, attachment, pp. 1–17.
[150] Cotton Australia, sub. 3, pp. 3–4.
[151] Kalamia, sub. 5, p. 2, sub. 15, p. 2.
[152] EQ, sub. 4, attachment, p. 14.

[154] QCOSS, sub. 18, attachment, pp. 19–20.

Stakeholder comment	Our response
QEUN also commented on the delayed public workshops on the draft determination.[155]	
EQ sought clarification on the treatment of distribution loss factor (DLF) adjustments in the N component, particularly for retail tariffs based on an Ergon Energy-based N component.[156]	Consistent with our previous practice, we have used the network charges (i.e. the network use of system charges) that EQ has submitted to the AER to determine notified prices. The treatment of network related loss factors is a matter for EQ (and its distribution businesses) and the AER to determine at the network level.
BRIG considered a sustainable and affordable retail electricity tariff would be one that has a ceiling of 8 c/kWh for the "electrons" and 8 c/kWh for the network, with QFF and Canegrowers proposing that retail electricity prices for agriculture be capped at this amount.[157]	In accordance with the delegation, we are required to consider setting notified prices using an N+R approach. The question of whether it is appropriate to develop new agricultural-oriented tariffs is a matter for EQ (and its distribution businesses) and the AER to determine at the network level.
QEUN recommended the Queensland Government lists as a motion for the next COAG Energy Council meeting an increase in the electricity point of connection levy collected by AEMO to $1.12 per year and that it supports a mechanism that provides equitable resourcing for business, residential and regional energy consumers to bring evidence-based recommendations to state and national energy policy tables and to the QCA.[158]	This matter is directed towards the Queensland Government and is outside the scope of this report.
QEUN said the UTP arrangements should be made transparent by reporting on how the UTP is defined and calculated and disclosing annually the distribution of the community service obligation by customer category, region and industry sector.[159]	This matter is outside the scope of this report. Reporting on the UTP is a matter for the Queensland Government.
QEUN said the removal of the non-reversion policy should be extended to include customers consuming up to 160 MWh per year.[160]	This is a matter for the Queensland Government and is outside the scope of this report.
QEUN recommended the introduction of the Traffic Light System of demand response to lower power bills and maintain reliability standards as the Queensland Government implements its 50% Renewable Energy Target by 2030.[161]	This matter is outside the scope of this report.
QEUN recommended the national reliability standard be maintained at 0.002% to prevent an increase in power bills.[162]	This matter is outside the scope of this report.
QEUN said there should be public acknowledgement that under the Constitution it is the responsibility of the Queensland Government, not the QCA, to set	As discussed in chapter 1, the responsibility for setting notified prices is set out in the Electricity Act. As expressly provided for under that Act, the

[155] QEUN, sub. 20, p. 8.
[156] EQ, sub. 14, attachment, p. 9.
[157] BRIG, sub. 10, p. 1; QFF, sub. 21, pp. 2–3; Canegrowers, sub. 11, p. 2.
[158] QEUN, sub. 20, p. 13.
[159] QEUN, sub. 20, pp. 26–27.
[160] QEUN, sub. 20, p. 27.
[161] QEUN, sub. 20, pp. 28–30.
[162] QEUN, sub. 20, p. 31.

Stakeholder comment	***Our response***
regulated retail electricity prices in regional Queensland.[163]	Minister has delegated relevant price setting functions to the QCA for 2020–21. Whether any further public statement is necessary is a matter for the Queensland Government.
EQ requested further information about the calculation of the N component for retail tariff 41. It considered the fixed and usage charge components should be consistent with the approach adopted for other small customer retail tariffs.[164]	Since price deregulation in SEQ in 2016–17, we have based the N component of retail tariff 41 on Energex's network tariff NTC 8300, on the basis that, while it is a large customer tariff, it was made available to small business customers on a voluntary basis. It appears that this network tariff will no longer be available to small business customers under Energex's recently approved network tariff reforms. As discussed in chapter 3, we decided to maintain existing retail tariffs and to not introduce new retail tariffs based on new network tariffs at this time. In accordance with those decisions, we have continued to base the N component of retail tariff 41 on NTC 8300 for this determination. We can consider this matter further in future determinations, including whether this tariff can be replaced by a new retail tariff based on an equivalent new network tariff.
QFF said it seeks a comprehensive assessment of the costs and benefits of revising the electricity network and transmission businesses' regulated asset base (RAB) to 'efficient levels'. It considered the RABs have been 'artificially inflated and inefficiently grown to excessive levels' and that, despite being subject to regulation, network costs, profits and prices 'continue to appear to be excessive'.[165]	In accordance with the delegation, we are required to consider setting notified prices using an N+R approach. The RABs for network and transmission businesses is a matter for the AER.
Canegrowers said that, in accordance with the QCA Act, we should take account of irrigators' ability to pay when determining final retail electricity prices for regional users.[166]	Our role in determining regional electricity prices is governed by the Electricity Act and the terms of our ministerial delegation. This framework sets out factors we must have regard to when making a price determination (see chapter 1). We note we have set prices in accordance with the Queensland Government's UTP, which, for customers on standard tariffs, means prices are generally set lower than the relevant cost of supply.
PV Water referred to our role under Part 3 of the QCA Act and referenced a number of matters under section 26 of the QCA Act to which it said we should have regard.[167]	Our role in determining regional electricity prices is governed by the Electricity Act and the terms of our ministerial delegation. This framework sets out factors we must have regard to when making a price determination (see chapter 1).
Mainstream Aquaculture queried why it is paying more for its electricity in Queensland than in Victoria	As discussed in ACIL Allen's final report, wholesale electricity costs in Queensland are the

[163] QEUN, sub. 20, p. 31.
[164] EQ, sub. 14, attachment, pp. 8–9.
[165] QFF, sub. 21, p. 3.
[166] Canegrowers, sub. 11, pp. 3–4.
[167] PV Water, sub. 17, pp. 1–2.

Stakeholder comment	***Our response***
and provided a chart of quarterly base futures prices by state.[168]	lowest of all distribution zones for 2019–20 and 2020–21.[169] More broadly, and without knowing the individual circumstances of Mainstream Aquaculture, we also note it is difficult to make comparisons between retail electricity prices in different jurisdictions due to differences in the characteristics of each network, such as customer density and other factors, which may influence the cost of supply.

[168] Mainstream Aquaculture, sub. 16, p. 1.
[169] ACIL Allen's final report, pp. 13–14.

6 FINAL NOTIFIED PRICES

This chapter sets out our notified prices for 2020–21. A breakdown of notified prices by cost component is provided in Appendix I.

Appendix K provides the gazette notice, which includes the final notified prices published in a tariff schedule, and the eligibility criteria and terms and conditions for accessing each tariff.

Table 2 Regulated retail tariffs and prices for residential customers (excl. GST), 2020–21

Retail tariff	***Fixed charge[a]***	***Usage charge (off-peak/flat)***	***Usage charge (peak)***	***Demand charge (off-peak)***	***Demand charge (peak)***
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 11—residential (flat rate)	90.676	21.756			
Tariff 12A—residential (time-of-use)[b]	75.091	19.084	55.966		
Tariff 14—residential (time-of-use demand)[c]	47.434	15.505		7.423	51.689
Tariff 31—night rate (super economy)		14.932			
Tariff 33—controlled supply (economy)		16.331			

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 3 Regulated retail tariffs and prices for small business and unmetered supply customers, other than street lighting (excl. GST), 2020–21

Retail tariff	***Fixed charge[a]***	***Usage charge (off-peak/flat)***	***Usage charge (peak)***	***Demand charge (off-peak/flat)***	***Demand charge (peak)***
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 20—business (flat rate)	128.266	23.258			
Tariff 22A—business (time-of-use)[b]	118.338	21.777	54.496		
Tariff 24—business (time-of-use demand)[c]	64.541	16.439		7.161	71.258
Tariff 41—low voltage (demand)	639.826	14.498		18.765	
Tariff 91—unmetered		20.366			

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 4 Regulated retail tariffs and prices for large business and street lighting customers (excl. GST), 2020–21

Retail tariff	***Fixed charge***	***Usage charge (off-peak/flat)***	***Usage charge (peak)***	***Demand charge (off-peak/flat)***	***Demand charge (peak)***	***Demand charge***[a]
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***	***$/kVA/mth***
Tariff 44—small (demand)	4021.494	11.668		26.142		23.528
Tariff 45—medium (demand)	13081.281	11.668		20.768		18.691
Tariff 46—large (demand)	34103.721	11.668		17.034		15.331
Tariff 50—seasonal time-of-use (demand)[b]	3368.897	13.532	11.459	10.495	66.700	
Tariff 71—street lighting		24.437				

a *Customers on tariffs 44, 45 and 46 will be charged for demand on either a kW or kVA basis, based on their metering arrangements.*

b *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).*

Table 5 Regulated retail tariffs and prices for very large business customers (excl. GST), 2020–21

Retail tariff	*Fixed charge*	*Usage charge (off-peak/flat)*	*Usage charge (peak)*	*Connection unit*	*Capacity*	*Demand charge*
	c/day	*c/kWh*		*$/day/unit*	*$/kVA of AD/mth*	*$/kVA/mth*
Tariff 51A—high voltage (CAC 66 kV)	24821.461	11.123		5.903	3.490	3.039
Tariff 51B—high voltage (CAC 33 kV)	18290.861	11.123		5.903	4.268	3.148
Tariff 51C—high voltage (CAC 22/11 kV Bus)	17159.661	11.123		5.903	4.926	3.817
Tariff 51D—high voltage (CAC 22/11 kV Line)	16513.261	11.123		5.903	9.571	7.699
Tariff 52A—high voltage (CAC STOUD 33-66kV)	13846.861	11.079	10.765	5.903	5.988	11.880
Tariff 52B—high voltage (CAC STOUD 22/11kV Bus)	13846.861	11.079	10.765	5.903	4.227	44.748
Tariff 52C—high voltage (CAC STOUD 22/11kV Line)	13846.861	11.079	10.765	5.903	7.749	78.117
Tariff 53—high voltage (ICC)	24639.027	11.123			3.490	3.039
ICC site-specific—high voltage	2457.427	9.827			0.199	0.173

Table 6 Obsolete regulated retail tariffs and prices (excl. GST), 2020–21

Retail tariff	*Fixed charge*	*Minimum 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)—obsolete	76.858					37.595		
Tariff 21—obsolete		72.631	49.357	46.374	35.303			
Tariff 22 (small and large)—obsolete	184.717		49.820		17.543			
Tariff 37[d]—obsolete		30.623	21.807		54.544			
Tariff 62—obsolete	78.451		46.516	39.336	16.448			
Tariff 65—obsolete	78.003		36.894		20.321			
Tariff 66—obsolete	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 10,000 kWh; tariff 65—12 hour 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 times; tariff 37—4.30 pm to 10.30 pm; tariffs 62 and 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 7 Obsolete high voltage regulated retail tariffs and prices (excl. GST), 2020–21

Retail tariff	***Fixed charge***	***Usage charge (off-peak/flat)***	***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

Table 8 Metering charges for large customers—advanced meters (excl. GST), 2020–21

Customer type	***Metering charge (c/day)***
Standard asset customer (annual usage of 750 MWh or less)	182.880
Standard asset customer (annual usage greater than 750 MWh)	217.109
Connection asset customer	430.155
Individually calculated customer	493.816

Source: Retailer data.