Queensland Competition Authority

Draft determination

Regulated retail electricity prices for 2020–21

Regional Queensland

March 2020

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SUBMISSIONS

Closing date for submissions: 13 May 2020

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (QCA). Therefore submissions are invited from interested parties concerning its assessment of regulated regional electricity prices for 2020–21. The QCA will take account of all submissions received within the stated timeframes.

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

Queensland Competition Authority
GPO Box 2257
Brisbane Q 4001

Tel (07) 3222 0555
Fax (07) 3222 0599
www.qca.org.au/submissions

Confidentiality

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

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

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

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

Public access to submissions

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

Contents

1 ABOUT OUR REVIEW

1.1 What have we been asked to do?

We have received a delegation from the Minister for Natural Resources, Mines and Energy to set regulated retail electricity prices (notified prices) to apply in regional Queensland (outside of the Energex area) in 2020–21. We are delegated this task by the Minister in accordance with the *Electricity Act 1994* (Electricity Act).[1]

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[2] 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.[3]

Matters we must consider under the delegation

The Minister's delegation (the delegation) includes a terms of reference, containing particular details and matters relevant to our price determination, namely:

- 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] Section 90AA of the Electricity Act.
[2] Section 90(5)(a) of the Electricity Act.
[3] Section 90(5)(b) of the Electricity Act.

1.3 Review process and key dates

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.

We received ten submissions in response to our paper. These are available on our website.

Draft determination

On 31 March 2020, we released this draft price determination. It contains draft notified prices, presented as bundled prices appropriate to the retail tariff structure (except for the site-specific tariffs).[4]

In making our determination, we have had regard to the relevant factors in the Electricity Act, matters set out in the delegation and comments from stakeholders on the interim consultation paper, and we have undertaken our own analysis.

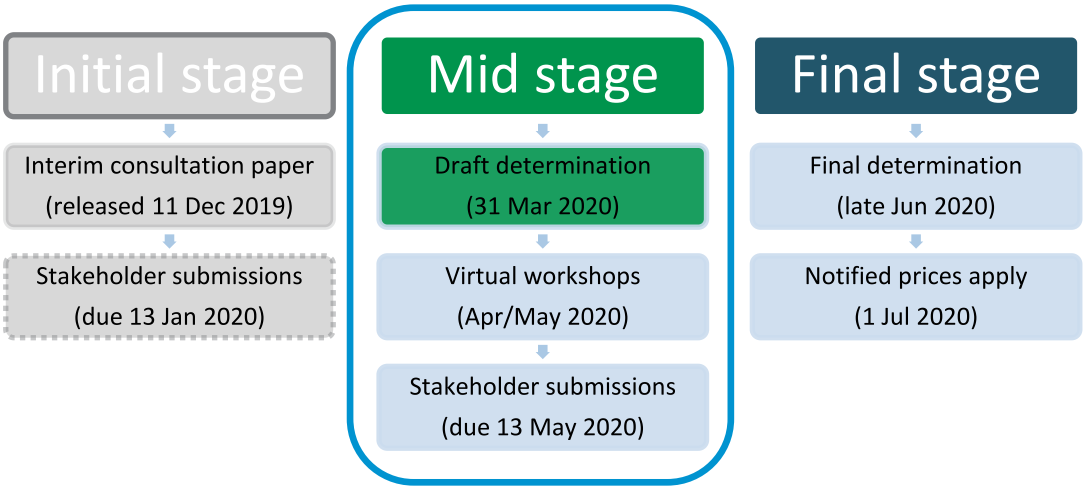
Stakeholders are invited to provide submissions on our draft determination. Information on making a submission is available on our website.[5]

Submissions on the draft determination are due by 13 May 2020.

We will consider all stakeholder submissions received by the due date, along with other relevant information, when making our final determination on notified prices.

Way forward and indicative consultation timetable

We are currently mid-way through the review process. For key dates from here, including when we intend to publish our final determination, see the consultation timetable below. To inform stakeholders about our draft determination, we plan to hold stakeholder workshops during April/May 2020. However, given the rapidly changing COVID-19 situation, we plan to hold virtual (rather than in-person) workshops this year, using video or phone conferencing. More information will be available on our website soon.



[4] As required in s. 8 of the delegation terms of reference (Appendix A).
[5] https://www.qca.org.au/submission-policy/.

It is important to note these timeframes are indicative and may change, particularly in light of any further COVID-19 developments. To keep up to date with the latest developments on this project (including workshop information), we encourage stakeholders to subscribe to our email alerts.[6]

1.4 Structure of this paper

We have structured our draft determination report as follows:

- Indicative bill impacts of draft 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)
- Draft notified prices (chapter 6).

1.5 Supporting documents

1.5.1 Information booklet

We have prepared an information booklet to accompany the draft determination report—it provides an 'at a glance' overview of our price setting process and draft notified prices (as contained in this report). The information booklet aims to help stakeholders to become quickly informed of key issues, which may make it easier to prepare submissions. It is designed to be read in conjunction with the draft determination report (not as a substitute).

1.5.2 Technical appendices

We have provided supporting and other information in the appendices as follows:

- Appendix A: Minister's delegation
- Appendix B: Submissions and references
- Appendix C: Network cost approach (small customers)
- Appendix D: Draft 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 draft notified prices
- Appendix J: Draft gazette notice.

[6] https://www.qca.org.au/email-alerts/.

2 INDICATIVE BILL IMPACTS OF DRAFT NOTIFIED PRICES

This overview provides an indication of the electricity bill a typical customer[7] would pay in 2020–21 (using draft notified prices) compared to the bill using 2019–20 notified prices.

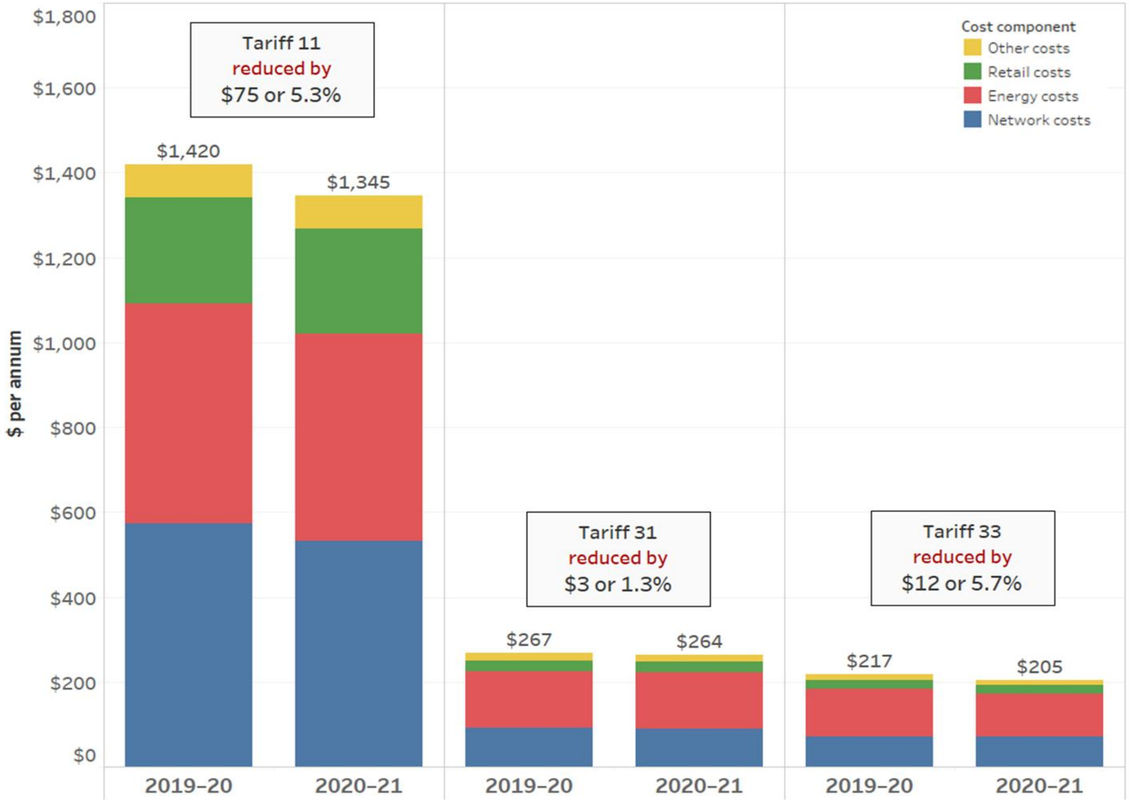
Overall, typical customers on all major tariffs can expect reductions in their notified price bills compared to 2019–20, largely due to an expected decrease in network and energy costs.

Our analysis for the draft determination is based on the latest information available at the time of publication and will be updated as part of our final determination.

2.1 Residential customers

Typical customers on the main residential tariffs—tariffs 11, 31 and 33[8]—are expected to pay between 1.3 per cent and 5.7 per cent less per annum for their electricity based on our draft notified prices.[9] However, it is important to note the bill impact will be different for customers with different levels of electricity usage.

Figure 1 Bills based on draft notified prices—typical residential customers (incl. GST)



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

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

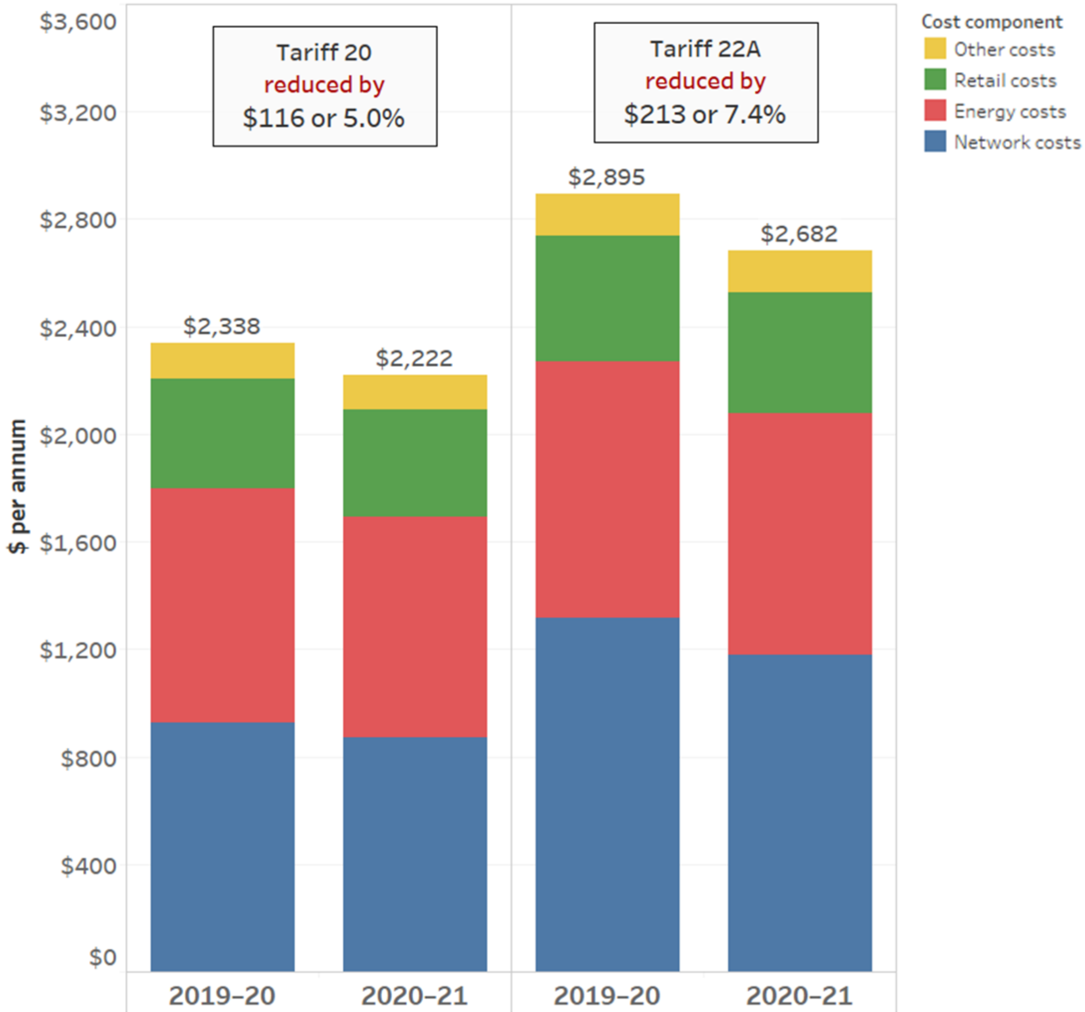
[8] Most residential customers are on tariff 11, but many customers also access controlled load tariffs—tariffs 31 and 33—for appliances that do not require a constant supply of electricity (e.g. hot water systems and pool pumps).

[9] 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[10]—are expected to pay between 5.0 per cent and 7.4 per cent less per annum for their electricity based on our draft notified prices.[11] However, actual bill impacts will depend on customers' levels or patterns of electricity usage.

Figure 2 Bills based on draft notified prices—typical small business customers (incl. GST)



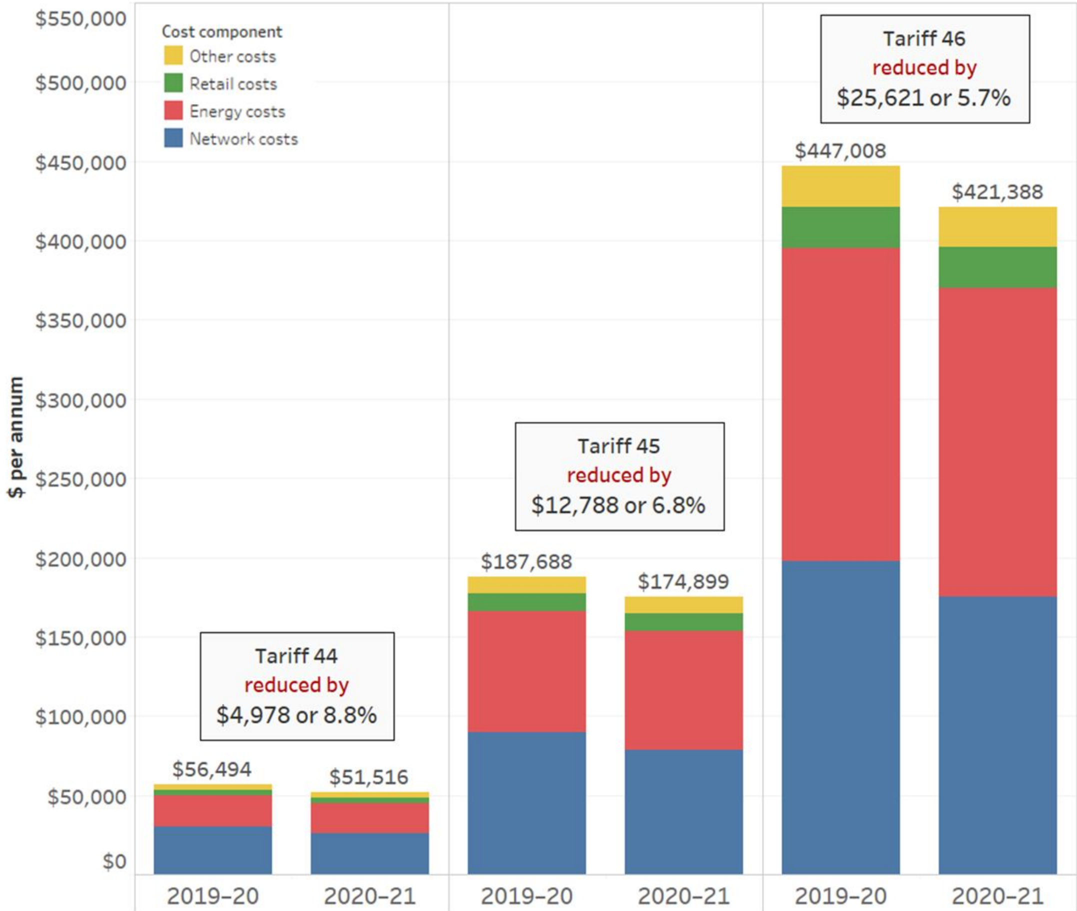
Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

[10] Tariff 20 is a flat-rate tariff and tariff 22A is a time-of-use tariff.
[11] 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 between 5.7 per cent and 8.8 per cent less per annum for their electricity based on our draft notified prices.[12] However, customers with different levels or patterns of usage can expect different bill impacts.

Figure 3 Bills based on draft notified prices—typical large business customers (incl. GST)



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

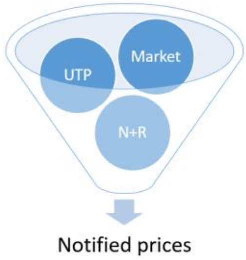
[12] Metering charges are excluded from the bill impact analysis.

3 OVERARCHING FRAMEWORK—POLICY AND PRICING MATTERS

This chapter provides our views on key overarching framework matters that influence our review and the notified prices set out in this draft determination.

Our consideration of these matters is as follows:

- the market environment (section 3.1)
- the methodology 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 the ongoing network tariff reforms (i.e. the expected regulatory decisions for distributors—Energex and Ergon Distribution—in Queensland on network costs and structures).

The Minister has asked us to consider the market environment in setting prices, including managing the potential impacts on retail customers from the network tariff reforms and ensuring regional customers benefit from the electricity cost protection provided by the uniform tariff policy (UTP). More specifically, the delegation requires us to have regard to matters arising from two reviews that the Australian Energy Regulator (AER) is undertaking:

- 2020–25 regulatory determination process for distributors[13]—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 increasingly complex structures to facilitate a move towards greater cost reflectivity
- default market offer (DMO) for south east Queensland (SEQ)—the AER sets a DMO that limits the prices charged to residential and small business customers on standard retail contracts. The DMO was first introduced in 2019–20. The AER released a draft determination on the 2020–21 DMO on 10 February 2020 and has indicated it will issue a final determination by April 2020.

Notably, the complex and evolving nature of the 2020–25 TSS means we are unlikely to have certainty on network tariff structures and prices prior to the AER's final decision in April 2020. In particular, the AER has not made a determination yet on the recently revised TSS proposals EQ submitted in December 2019.

The proposed network tariff reforms, including key processes and proposed TSS milestones, are summarised in Box 1.

[13] The AER website provides more information on these reviews, for example, Ergon Energy—Determination 2020–25 and Energex—Determination 2020–25.

Box 1: Network tariff reforms

EQ proposed to replace the flat-rate network tariffs for small customers[14] 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 continue 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 further substantial changes to the TSS are 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 latest revised proposal includes:[15]

- 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 wide inclining fixed tariff (WIFT) 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. They were designed to minimise the impact on customers transitioning to the new cost-reflective network tariffs.

The AER's final decision on each revised TSS is due by 30 April 2020.

3.2 Draft pricing approach

3.2.1 Matters in the delegation

The terms of the delegation require us to consider:

- the 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'

[14] Small customers with new and existing digital meters.
[15] For more information on EQ's tariff package and strategy, see its December 2019 TSS proposal, which is available on the AER website.

and, where practicable, customers are 'provided new and additional choice of retail tariffs resulting from the network tariff reform agenda'.[16]

While the UTP and N+R methodology are broadly consistent with what we have been required to consider in previous years, 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. We therefore need to consider setting notified prices having regard to:

- UTP cost considerations, noting that in the past we based prices on:
  - for small customers[17]—the costs of supplying small customers in SEQ
  - for large customers[18]—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:
  - 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

There was broad stakeholder support for continued use of the UTP to set notified prices.[19] Several stakeholders said the cost of electricity continues to be a key issue in regional Queensland[20] and cost must be 'front of mind' when setting prices so customers do not pay 'a cent more than they should have to.'[21]

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

[16] Minister's cover letter, p. 1 (Appendix A).
[17] 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.
[18] 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.
[19] 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.
[20] ASMC, sub. 1, pp. 1–2; Cotton Australia, sub. 3, p. 1; Kalamia, sub. 5, pp. 1–2.
[21] QCOSS, sub. 7, p. 1.

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.[22]

There was stakeholder support for maintaining the existing retail tariff structures in our determination of notified prices.[23] It was suggested that 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[24], or at least compare the new tariffs with those currently available.[25]

EQ said network tariff reforms are required to assist customers' transition towards the changing electricity market, including through giving more tariff options, especially for customers with digital meters.[26] It said its strong preference is to pass through the new network prices and tariffs into notified prices, while continuing to have regard to the UTP.[27] However, it noted there were several issues that would need to be resolved, including that customers generally prefer simplicity over complexity. As a result, EQ suggested it was important for the QCA to consider how retailers will package the new network tariffs into retail tariffs to appropriately reflect the intent of the UTP.[28] EQ supported maintaining existing retail tariffs whose underlying network tariffs would be removed (under EQ's proposal). It also suggested that access to these tariffs should be closed off to new customers.[29]

Queensland Consumers' Association was concerned about the 'major uncertainties' regarding how any changes to network tariffs would affect retail tariff structures in SEQ. It said we should be very cautious implementing changes related to network tariff reforms to take account of this.[30]

Stakeholders also raised concerns about the lack of clarity around new pricing structures, the delays in the network reform process, and the effect this would have on setting notified prices in the coming year.[31]

Cotton Australia requested that we provide more information on the changes that may result from the new tariff structures with regard to the UTP. It also suggested that our process may need to be more flexible this year, such as by delaying the release of new tariffs until a few months into the determination period, which would allow customers time to consider and compare the new tariffs for the remainder of the year.[32] QCOSS said any new tariffs implemented should have sufficient accompanying material, including communications, education and information for customers to compare bill impacts.[33]

[22] Cotton Australia, sub. 3, p. 6; Kalamia, sub. 5, p. 2.
[23] QCOSS, sub. 7, attachment, pp. 4–5.
[24] QCOSS, sub. 7, p. 2.
[25] Cotton Australia, sub. 3, p. 6.
[26] EQ, sub. 4, attachment, p. 1.
[27] EQ, sub. 4, p. 1.
[28] EQ, sub. 4, attachment, p. 1.
[29] EQ, sub. 4, attachment, p. 14.
[30] Queensland Consumers' Association, sub. 8, p. 1.
[31] Cotton Australia, sub. 3, pp. 3, 5–6; NSA, sub. 6, p. 1; QCOSS, sub. 7, pp. 1–2.
[32] Cotton Australia, sub. 3, pp. 3, 5–6.
[33] QCOSS, sub. 7, pp. 1–2, attachment, pp. 4–5, 13.

3.2.3 Analysis and draft position

Having regard to the relevant factors, stakeholder comments and our own analysis, we have formed draft views on how we will have regard to the UTP and N+R methodology when setting notified prices this year.

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 that 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 propose to continue setting notified prices in accordance with the Queensland Government's UTP. We note 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
- 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, 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, approximately $498 million is budgeted to provide subsidised electricity prices for regional customers.[34]

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, significant changes are proposed to the underlying network tariffs for retail tariffs—particularly those in respect of small customers—which have yet to be approved by the AER.

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 establish new retail tariffs to reflect proposed new network tariffs, and whether to maintain existing retail tariffs.

Small customers

Our draft 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 proposed new network tariffs.

We considered whether to introduce new retail tariff structures based on the proposed new network tariff reforms, but do not consider it appropriate to do so at this time. The new network tariff structures are complex and evolving, and we cannot currently anticipate whether they will be approved (without further amendment) by the AER in its final determination.

[34] Queensland Government (2019), p. 20.

Further, the full terms and conditions of some network tariffs are yet to be proposed (such as the new proposed load control tariffs for small and large business customers).[35]

Importantly, as EQ pointed out, a key consideration is how retailers will package Energex's proposed new network tariffs into SEQ customer retail tariffs. We consider this particularly relevant, given that 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 will respond, or whether they will offer tariff options based on the more complex suite of network tariff structures EQ has proposed. In the past, more complex tariff options were not popular among retailers and customers alike. For instance, Energex and Ergon Energy trialled Lifestyle Package tariffs in 2018, but due to limited retailer or customer response, they decided to discontinue them.[36]

We appreciate that some customers may want these proposed network tariffs to be introduced at the retail level as part of this determination—for example, to provide customers with the opportunity to compare the impacts of different tariff options on their bills and to be able to access those new tariffs. However, we consider there is not enough certainty for us at this stage to establish new retail tariffs based on these proposed new network tariffs. Given the changes in the market (including the network 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.

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

We note our position to maintain existing retail tariffs will have implications for the determination of the network cost component for these tariffs, given there will be a misalignment with the underlying network tariffs (discussed in chapter 4).

Large customers

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

Our draft position is to base notified prices on the proposed 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 that EQ proposed for large customers are substantially consistent with structures that apply now).

We propose to not establish new retail tariffs based on proposed new network tariffs for large customers, namely the new default time of use demand tariff and load control tariffs. Similar to our position in respect of small customers, we consider there is insufficient certainty to incorporate these within notified prices at this stage. For instance, we note the AER has sought

[35] In addition, we do not have enough information at this stage about the load profile of these tariffs to appropriately determine the energy costs for these tariffs. Our approach to determining energy costs is discussed in chapter 4 and ACIL Allen's draft report (available on our website).

[36] Energex 2019d, p. 36.

further information from Ergon Distribution on the proposed new default time of use demand tariff[37] and, as discussed above in respect of small customers, there are uncertainties about the full terms and conditions of the proposed new load control tariffs.[38]

However, subject to stakeholder views, there are some aspects of proposed network tariff reforms that we do propose to incorporate into notified prices:

- removal of tariffs 52A–C (time of use demand tariffs for connection asset customers) to reflect Ergon Distribution's proposed removal of the underlying network tariffs for these retail tariffs, which the AER has not objected to as part of its draft decision.[39] We propose to take this approach because there are only a very small number of customers that are on these tariffs and there are other tariff options available to them, such as tariffs 51A–D (demand tariffs for connection asset customers).
- removal of excess kVAr charges[40], noting the AER has supported this in its draft decision[41]
- introduction of kilovolt ampere (kVA) demand-based charging parameters for particular tariffs, with kilowatt (kW) charging available where customer metering does not support kVA billing.[42] We note the AER has provided in-principle support for this reform (subject to further supporting information being provided).[43] We will reconsider this matter in our final determination if EQ's proposal is ultimately not approved by the AER.

We consider that these changes to tariff structures are minor and that large customers are sophisticated and well-equipped to assess and manage the impacts (if any) at the individual customer level.

3.3 New pricing issues

3.3.1 Solar bonus scheme (SBS) costs

On 21 February 2020, we received advice from EQ of Energex and Ergon Distribution’s intention 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 are due to the AER in May 2020 to take effect from 1 July 2020.

Stakeholder submissions

EQ has said that we should include SBS costs as part of our draft determination of notified prices.[44] Cotton Australia, on the other hand, said that any solar rebates/incentives (i.e. SBS

[37] AER 2019b, attachment 18: tariff structure statement, pp. 49–50.
[38] In addition, we also have insufficient information at this stage about the load profile of these tariffs in order for us to appropriately determine the energy costs for these tariffs. For further information on our approach to determining energy costs, see chapter 4, Appendix E and ACIL Allen’s draft report (available on our website).
[39] Ergon Energy 2019c, p. 25.
[40] 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.
[41] AER 2019b, attachment 18: tariff structure statement, p. 50.
[42] Ergon Energy 2019c, p. 27; Ergon Energy 2019d, pp. 44–45.
[43] AER 2019b, attachment 18: tariff structure statement, p. 49.
[44] EQ, sub. 4, attachment, p. 3.

costs) provided by the government should be funded through consolidated revenue and not through electricity charges.[45]

Analysis and draft position

Having regard to the relevant factors, stakeholder comments and our own analysis, our draft decision is to reflect the jurisdictional scheme amounts supplied by EQ in the draft notified prices set out in our draft determination (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 acknowledge we have reflected jurisdictional scheme amounts in our draft price determination ahead of Energex and Ergon Distribution submitting their annual price proposals to the AER. We have done so to provide as fulsome and accurate a picture of proposed notified prices as possible, so that stakeholders can better assess the proposed prices and the associated changes in indicative customer bills.

In the final determination, we expect to use updated jurisdictional scheme amounts included in the distributors' annual pricing proposals to the AER. The use of proposed amounts (rather than those 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'.[46]

Analysis and draft position

Having regard to the relevant factors, stakeholder comments and our own analysis, we intend to implement the arrangements consistent with the delegation. In light of 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 upon establishing an electricity account. This is consistent with government expectations and is broadly supported by stakeholders.[47]

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).

[45] Cotton Australia, sub. 3, p. 7.
[46] See Appendix A for the Minister's cover letter.
[47] Queensland Consumers' Association, sub. 8, p. 1; Kalamia, sub. 5, p. 2; EQ, sub. 4, attachment, p. 4; QCOSS, sub. 7, p. 1; attachment, p. 6.

3.3.3 Individually calculated customer (ICC) tariffs

Individually calculated customers (ICC) 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.

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 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.[48]

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.[49]

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, noting that, while Ergon Energy has had preliminary discussions about this with cotton ginning companies, it is not clear to customers whether they would be better off or not.[50]

EQ identified issues we would need to consider 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.[51]

Analysis and draft position

Having regard to the relevant factors, stakeholder comments and our own analysis, we propose to introduce notified prices based on site-specific network charges. We consider providing this optionality for customers 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.

Such an approach would result 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 and retail costs, headroom and cost pass-through) determined by us.

To determine the non-N component of site-specific tariffs, we propose to use the non-N component we determine for tariff 53. We consider this approach is appropriate, because we

[48] Minister's cover letter, p. 3 (Appendix A).
[49] ASMC, sub. 1, pp. 1–2.
[50] Cotton Australia, sub. 3, pp. 5–6.
[51] EQ, sub. 4, attachment, pp. 4–5.

are determining tariff 53 for the same group of very large customers that will have access to site-specific tariffs.

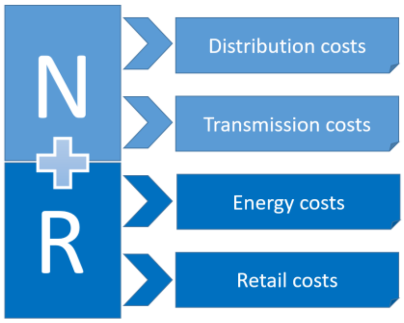
Determining a non-N component for each site-specific tariff would be administratively complex. This is because our proposed approach to determine the non-N components is to calculate variable retail costs and headroom as a percentage of other cost components (see chapters 4 and 5), and each site specific retail tariff has a different network cost 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 draft 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.

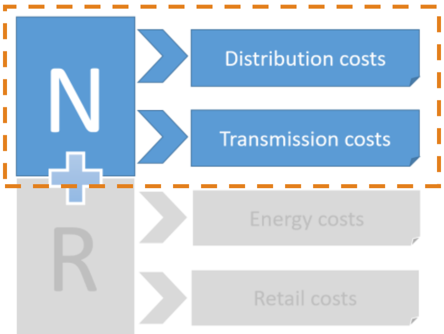


This chapter sets out our draft positions in respect of:

- 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, jurisdictional scheme charges generally include the Solar Bonus Scheme (SBS) and AEMC levy costs. We have received advice from EQ on its intention to include jurisdictional scheme charges as part of network prices for 2020–21 (see chapter 3 and Appendix D).

Our proposed approach to determining the N component differs from previous years in light of the ongoing network tariff reforms. Overall, total network costs are expected to reduce by 1.5 per cent to 10.4 per cent for small customers, and 11.2 per cent to 14.6 per cent for large customers, depending on the tariff.

Our draft position (chapter 3) is to:

- for small customers—maintain the existing retail tariffs
- for large customers—base the retail tariffs on proposed 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 network tariffs being proposed by Energex and Ergon Distribution as part of the AER's network determination process.

This section sets out our views on how to determine the N component of notified prices, in light of the above draft positions—in particular, our consideration of whether to:

- pass through the network prices[52] determined 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 (i.e. the alternative approach).

4.1.1 Stakeholder submissions

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

EQ considered this option has 'potential to deliver results which are inaccurate, distort the price signal and could result in the need for new transition paths in future years as regulated retail tariffs are rebased to the true 'N'.' Instead, it proposed that we base our calculation of the N component on the draft network tariffs that Energex and Ergon Distribution submitted to the AER in December 2019.[53] QCOSS also considered that we should determine the N component based on actual network tariffs for 2020–21, at least for our final determination when network tariffs should be known.[54]

Canegrowers also said that 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 reasonable estimate of the actual costs of making, producing or supplying the goods and services'.[55]

4.1.2 Analysis and draft position

Having regard to the relevant factors, stakeholder comments and our own analysis, we have formed draft views on how we will determine the N component of notified prices for small and large customers.

Our draft position is to:

- for small customers—apply a price indexation approach to reflect the changes in network costs determined by the AER
- for large customers—pass through the network prices determined by the AER.

Small customers

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

However, given our draft position of maintaining existing retail tariffs for small customers (see section 3.2.3), we are unable to use that same approach in this price determination. This is because EQ has proposed to retire most of the network tariffs that underpin the existing retail tariffs.

Furthermore, we are unable to align the existing retail tariffs with the new proposed network tariff structures and prices considering the material difference between the proposed network tariffs and the current network (and retail) tariff structures. There is also uncertainty over the final form of network tariff structures and prices that the AER will approve. While we acknowledge there is greater certainty about particular network tariffs (such as Energex's flat-

[52] For the purposes of this report, 'network costs/prices' is a general reference to distribution and transmission costs/prices, unless otherwise indicated.
[53] EQ, sub. 4, attachment, pp. 3, 5.
[54] QCOSS, sub. 7, attachment, pp. 7–8.
[55] Canegrowers, sub. 2, p. 2; attachment, p. 15.

rate network tariffs for small customers), these are part of an overall package of proposed network prices. If the AER decides to make amendments to any of these network tariffs or prices, further adjustments to the proposed network prices are likely needed to ensure that the revenue recovered from network prices does not exceed the allowable network revenue.

Accordingly, we need to use an alternative approach to determining the network costs for the purposes of our price determination.

Price indexation approach

Our draft position is to determine the N component for existing small customer retail tariffs by using a price indexation approach, specifically an 'X-factor' approach.[56] This is essentially an approach that 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.

We note EQ has raised concerns about using an indexation-based approach to determine the N component, including that it will require transition paths in future years to ‘rebase’ regulated retail tariffs to the true ‘N’.[57] As discussed above, we consider our proposed indexation-based approach is necessary, given the uncertainty associated with the ongoing network tariff reforms. In deciding on an appropriate approach, we have taken into account the terms of reference for our review, which direct us to consider the use of a price indexation methodology in the event of significant uncertainty of both the prices and price structures of network tariffs.[58] Our proposed approach is also consistent with the AER's proposed approach to determine network costs for its upcoming DMO for SEQ, as noted in its draft decision.[59]

We consider the issue of rebasing retail tariffs could be considered in future price determinations if EQ amends (or ‘rebases’) network tariffs in future pricing proposals, including the extent to which existing retail tariffs should be maintained or phased out. This is likely to be one of many 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.[60] However, our proposed X-factor 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. This approach uses the X-factors set by the AER in its network determination, which reflects the AER’s determination of the efficient costs that transmission and distribution companies are entitled to recover. Accordingly, we consider the use of our proposed indexation approach is appropriate, as it reflects the underlying network costs, and we do not consider it is inconsistent with the Electricity Act.

In relation to the jurisdictional scheme charges (discussed in chapter 3), our draft decision is to incorporate these proposed charges into network costs for small customers as advised by EQ

[56] 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.

[57] EQ, sub. 4, attachment, pp. 3, 5.

[58] Terms of reference, schedule, cl. 2(e)(vi).

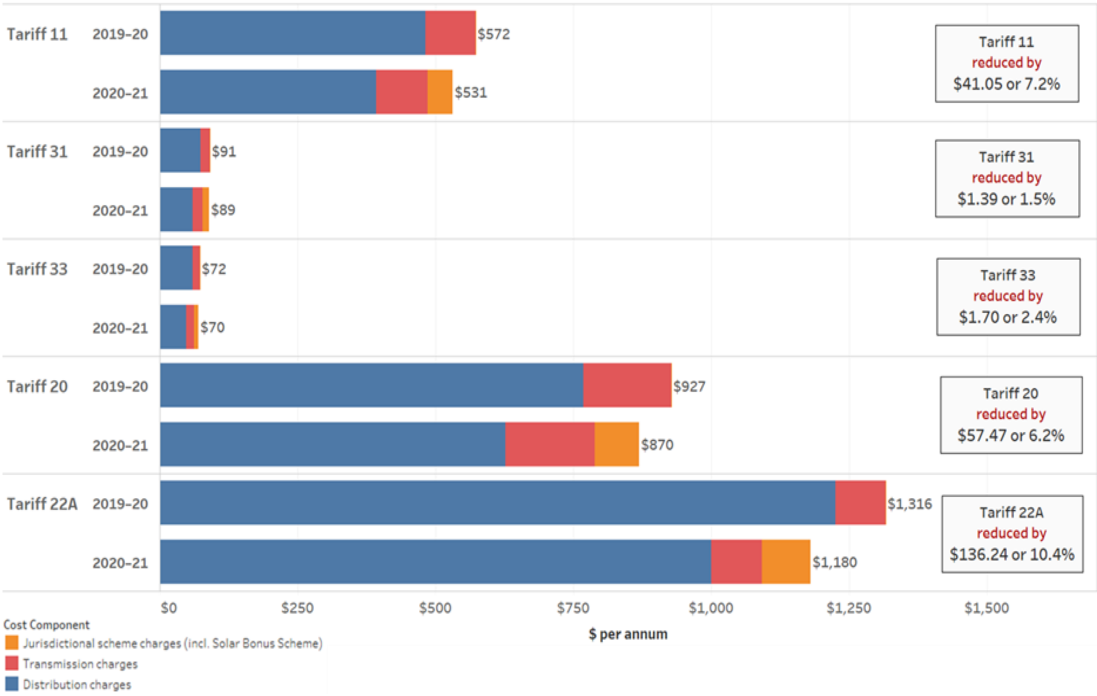
[59] AER 2020, pp. 41–43.

[60] Canegrowers, sub. 2, p. 2, attachment, p. 15.

(see Appendix D). This will provide stakeholders with a more fulsome and accurate picture of the network costs expected to be incurred by retailers.

The following chart shows the network costs included in our draft notified prices for small customers, compared to last year's estimates.

Figure 4 Draft 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

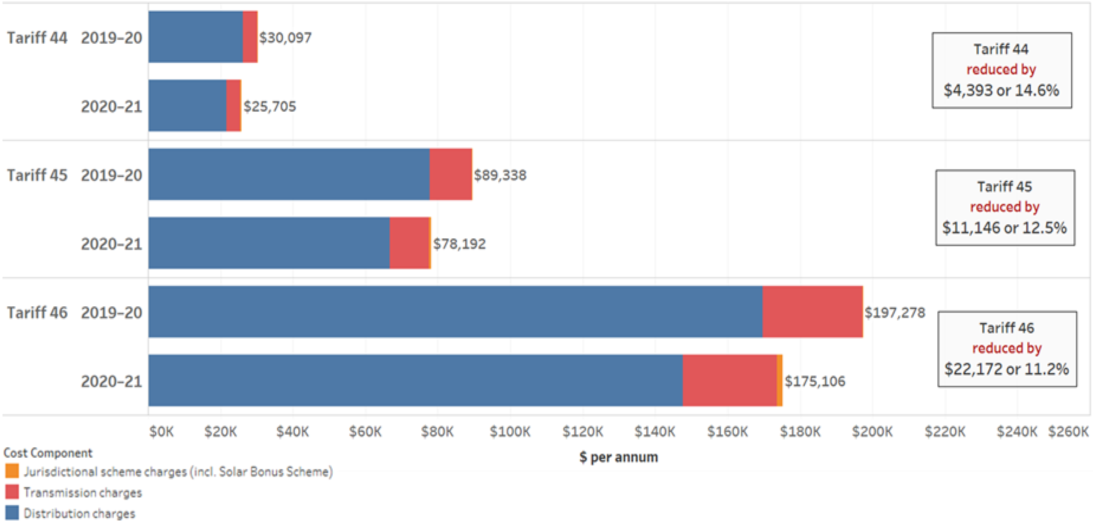
Given our draft position is to base the large customer retail tariffs on proposed network tariffs that have similar structures to those currently in place, we propose to apply the standard N+R approach for determining the N costs for these tariffs. This approach will pass through the 2020–21 network prices determined by the AER.

Due to the timing of our draft determination, we have used the 2020–21 network prices that Ergon Distribution submitted to the AER as part of its revised proposal in December 2019 (being the latest publicly available data). For our final determination, we intend to use the updated pricing approved by the AER in its network determination, which is due by 30 April 2020.

Our draft decision is to incorporate the proposed jurisdictional scheme charges (discussed in chapter 3) into network costs for large customers as advised by EQ (see Appendix D). This will provide stakeholders with a more fulsome and accurate picture of the network costs expected to be incurred by retailers.

The following chart shows the network costs included in our draft notified prices for large customers, compared to last year's estimates.

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

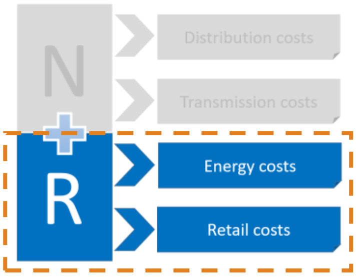


Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

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 propose to use broadly the same approach to determine the R component this year:



- Total energy costs are expected to reduce by 1.7 per cent to 8.4 per cent for small customers, depending on the tariff, and by 1.4 per cent for large customers, across all tariffs.
- Total retail costs are expected to reduce by 0.9 per cent to 6 per cent for small customers, and 1.3 per cent to 4.5 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.[61] Our draft 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.[62]

[61] ACIL Allen's draft report is available on our website.
[62] QCOSS, sub. 7, attachment, p. 9; EQ, sub. 4, attachment, p. 6.

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.[63] ACIL Allen demonstrated that its proposed methodology adequately addresses EQ's concerns by incorporating the latest data on solar generation when estimating wholesale energy costs.[64]

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 propose to determine 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 January—to take into account the most current information (including developments over the potentially volatile summer period).[65]

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

Analysis and draft position

Our draft decision is to determine wholesale energy costs based on ACIL Allen's advice, using a market hedging approach and up-to-date market data.

We consider that this approach is transparent and likely to produce robust estimates that best reflect the actual costs retailers incur when purchasing electricity from the NEM. The 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.[66] This means it adequately takes into account the likely variation in demand profiles and generation supply/costs within the NEM, while still meeting our draft determination timeframe. The AEMC also endorsed a market hedging approach in its 2013 advice on best practice retail regulation.[67]

Compared to the estimates from last year, our estimates of wholesale energy costs:[68]

- decrease for small customer tariffs (excluding tariff 31)—reflecting the projected decrease in spot price volatility in Queensland and other NEM regions
- increase marginally for large customer tariffs—reflecting the increasing proportion of electricity from the grid consumed during peak periods due to the uptake of rooftop solar PV in the Ergon area

[63] EQ, sub. 4, attachment, pp. 6–11.
[64] More details are available in chapter 3 of ACIL Allen's draft report.
[65] See Appendix E for a detailed description of ACIL Allen's market hedging approach.
[66] This is discussed further in Appendix E and addressed in chapter 3 of ACIL Allen's draft report.
[67] AEMC 2013.
[68] As discussed in chapter 3, our draft 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 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.

- increase marginally for tariff 31—reflecting the volume and pattern of electricity consumption on tariff 31, which are controlled by Energex. The majority of electricity consumed on tariff 31 occurs between 10 pm and 2 am, 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 draft report.

Other energy costs and losses

Retailers incur other energy costs 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[69]
- 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).

Analysis and draft position

Our draft 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 how

[69] The RET, comprised of the Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES), provides incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions.

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 51 per cent ($4.82/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 34 per cent ($2.46/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 11 per cent ($0.07/MWh)—reflecting the higher costs that AEMO expects to incur when managing the NEM
- ancillary services charges have increased by 100 per cent ($0.37/MWh)—reflecting a surge in demand for ancillary services, including due to the Basslink interconnector outage in Tasmania and the planned outage of the Heywood to Mortlake line in Victoria
- prudential costs have decreased by approximately 23 per cent ($0.50/MWh) for small customer tariffs and by about 9 per cent ($0.14/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:

- decreases for small customer retail tariffs by 12 per cent ($2.42/MWh)
- decreases for large customer retail tariffs by 11 per cent ($2.06/MWh).

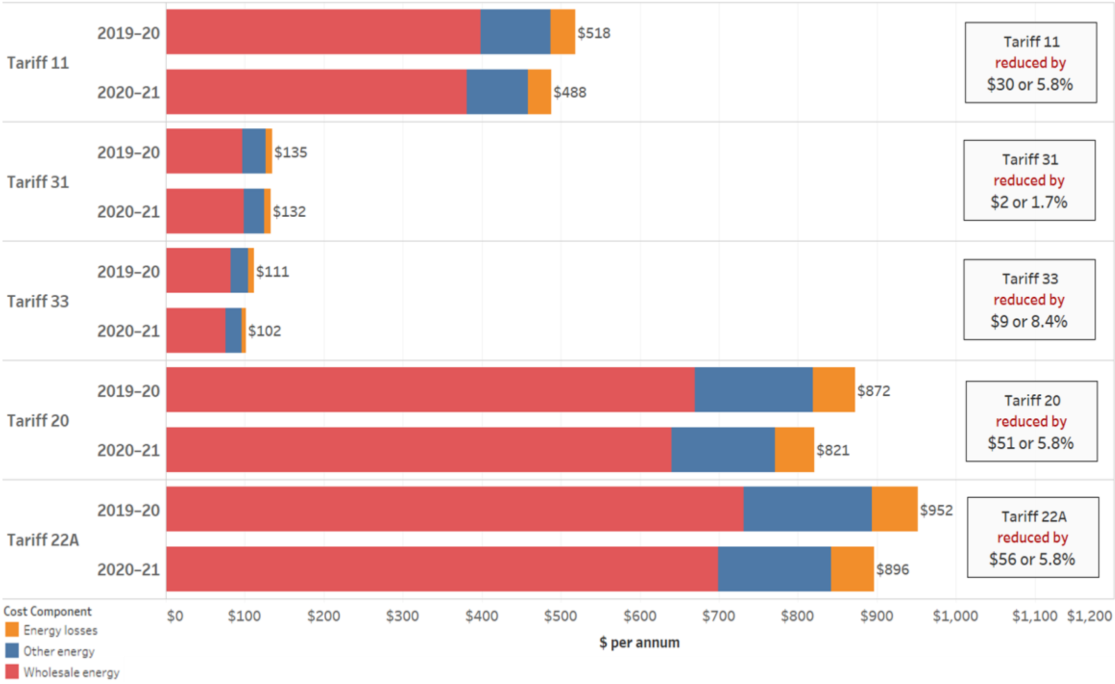
For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix E and ACIL Allen’s draft report.

We note that the energy losses in ACIL Allen's draft report are based on AEMO's 2019–20 published loss factors, as loss factors for 2020–21 have not yet been published. ACIL Allen will update the loss factors using AEMO's 2020–21 loss factors in its final report.

Total energy costs included in draft notified prices

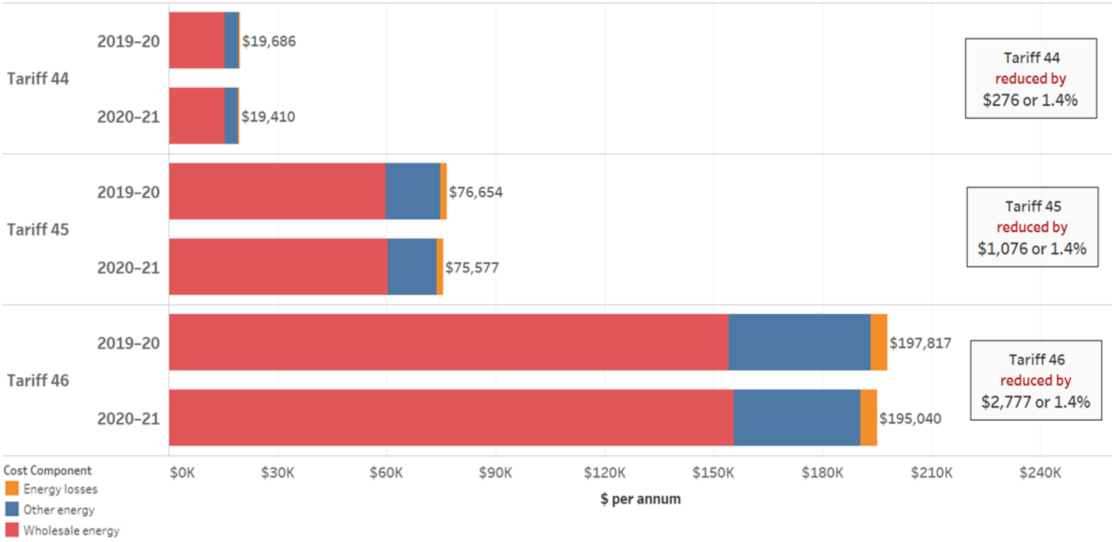
The following charts show the overall energy costs included in draft notified prices, compared to last year’s estimates—by tariff type for the typical small and large customers.

Figure 6 Draft 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.

Figure 7 Draft 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.[70]

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.[71] In determinations since then, we have updated the 2016–17 cost estimates:

- The fixed cost allowances have been adjusted for the forecast change in the CPI (to maintain the allowances in real terms).
- The variable retail cost percentage allocators have been maintained at 2016–17 levels.[72]

Our draft position for this review is to continue to use this approach to update the 2016–17 cost estimates.

Stakeholder submissions

While there was broad support for retail cost estimates to reflect efficient costs, stakeholder views differed with regards to what efficient costs were.

QCOSS was of the view that 'customers must not bear any of the cost-burden of the reforms themselves including any unreasonable transitional costs'.[73] Further, both Queensland Consumers' Association and QCOSS contended 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.[74]

On the other hand, EQ considered we should allow for the recovery of compliance 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.[75]

Analysis and draft decision

We consider there may be merit in establishing new retail cost allowances reflecting up-to-date information. However, we are concerned that the information we would expect to rely on, including retail market offers and cost data, would not be reliable, given recent and ongoing policy reforms. The key reforms likely to impact our assessment are the network tariff reform and the recent introduction of the DMO:

[70] Consistent with previous determinations, we have separated the large customer non-AER regulated metering costs from retail costs, and estimated metering charges separately (see section 5.6).
[71] 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.
[72] 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).
[73] QCOSS, sub. 7, p. 2.
[74] QCOSS, sub. 7, attachment, pp. 10–11; Queensland Consumers' Association, sub. 8, p. 2.
[75] EQ, sub. 4, attachment, pp. 12–13.

- Network tariff reform—the potential introduction of more complex network tariff structures in mid-2020 (see chapter 3) 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.
- Introduction of the DMO—current market prices are unlikely to be a reliable basis for estimating retail costs, given the retail market is still likely to be adjusting to the introduction of the DMO in mid-2019. We also noted the AER's view 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 …[76]

While QCOSS supported establishing new retail cost allowances[77], the limitations we have identified suggest that such an approach is unlikely to produce more reliable and robust cost estimates than if we continued with our current approach of updating 2016–17 cost estimates. Our current approach is broadly consistent with the AER's approach in its recent draft determination of the DMO for 2020–21. After assessing potential step changes in retail costs, the AER considered that no specific adjustments were necessary, and made a draft determination to adjust the previous year's retail cost estimate to reflect forecast changes in the CPI.[78]

Stakeholders had different views about whether retail costs in 2020–21 would be higher or lower than the current allowances. EQ suggested that retailers would incur additional costs in the short to medium term associated with regulatory compliance and national policy initiatives.[79] Consumer groups, on the other hand, expected a reduction in retail costs due to, among other things, the greater use of electronic billing and online channels to service customers, and lower financing costs.[80]

Our draft position is that it is appropriate at this time to continue with our current approach of updating the 2016–17 cost estimates. We consider this approach is reasonable in the circumstances, but will consider whether it is appropriate to revisit our approach to estimating retail costs as part of the next price review.

Residential and small business customers (small customers)

For small customer tariffs, we propose to:

- adjust 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[81]—to maintain the fixed component in real terms

[76] AER 2020, p. 25.
[77] QCOSS, sub. 7, p. 2.
[78] AER 2020, pp. 8–9, 22, 44–48.
[79] EQ, sub. 4, attachment, pp. 12–13.
[80] QCOSS, sub. 7, attachment, pp. 10–11; Queensland Consumers’ Association, sub. 8, p. 2.
[81] The RBA has forecasted a change in the CPI of 2 per cent for the period ending June 2020 and 1.75 per cent for the period ending June 2021. We have taken an average of these forecasts to derive a value of 1.875 per cent for 2020–21. See RBA 2019, p. 70.

- maintain 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.

Large customers

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

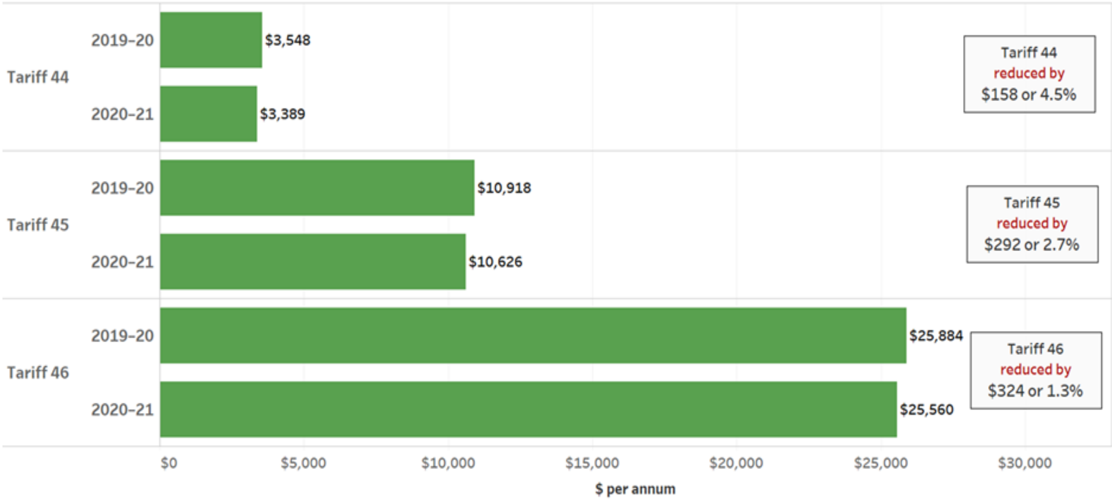
Total retail costs included in draft notified prices

Retail costs are generally forecast to decrease, compared to 2019–20. This is primarily due to a forecast 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 our draft notified prices to the 2019–20 allowances—by tariff type for typical small and large customers.

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

Figure 9 Draft 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 provides our draft views on other costs and pricing issues 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.

This chapter discusses the following matters:

- 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—that is, 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 be adjusted to include the standing offer adjustment, including because:

- regional customers would be required to pay more for their electricity when they do not have access to market contract prices, which would be inconsistent with the UTP
- there is doubt around whether standing contracts provide significant protections (and therefore value) for consumers compared to market contracts.

For these reasons, many stakeholders said the adjustment value should ideally be zero, but no more than 5 per cent.[82] Stakeholders also said that we should not simply carry forward the 5 per cent value this year, but should undertake and publish more robust analysis of the value customers place on having standard terms and conditions, for stakeholder comment.[83]

[82] QCOSS, sub. 7, p. 2; attachment, pp. 12–15; Queensland Consumers' Association, sub. 8, p. 2.
[83] QCOSS, sub. 7, p. 2; attachment, pp. 12–15.

However, 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'.[84]

Consumer groups submitted that the value of the adjustment (if included) should be reduced to ensure notified prices do not exceed the equivalent DMO for SEQ set by the AER.[85]

Analysis and draft position

We have been directed to consider basing the standing offer adjustment on the value of more favourable standard contract terms and conditions relative to market contracts and to include a similar adjustment to previous determinations (i.e. 5 per cent of total costs).

Standard contracts typically provide more favourable terms and conditions than market contracts. These benefits include simpler pricing, access to 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 our previous determination, we considered the fees and charges that an SEQ customer would likely incur on a market contract to enjoy the benefits of more favourable terms and conditions of a standard contract. Our 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 this analysis, we considered that it provided a useful indication of the potential maximum amount that 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 of our 2019–20 determination[86], and the requirement in the delegation to consider applying a similar adjustment to previous determinations, our draft decision is that maintaining the adjustment at 5 per cent of total costs is reasonable.

However, consistent with the delegation, we consider that the adjustment should be reduced if the resulting notified price bill would exceed the equivalent DMO reference bill in SEQ. Customers on notified prices would then generally not pay more than customers on equivalent default market offers in SEQ.

While we acknowledge that some stakeholders would prefer no standing offer adjustment, notified prices that include a 5 per cent adjustment (or lower adjustment if the DMO cap applies) remain well below the actual costs of supply. In the absence of the government's policy that regional customers should have access to electricity prices that are below-cost, we may need to consider whether greater weight should be placed on the actual costs of supply when determining notified prices.[87]

For the purposes of calculating draft notified prices, we have applied a 5 per cent adjustment, because it is not yet clear whether a downward adjustment will be necessary to align with the

[84] Energy Queensland, sub. 4, attachment, p. 13.
[85] QCOSS, sub. 7, p. 1; attachment, p. 15; Queensland Consumers' Association, sub. 8, p. 2.
[86] QCA, *Regulated retail electricity prices for 2019–20*, final determination, May 2019, chapter 6.
[87] See s. 90(5) of the Electricity Act.

DMO reference bill. The AER has not yet determined the final DMO, and the draft DMO does not provide an appropriate basis to make an adjustment, because it does not include an allowance for the recovery of jurisdictional scheme charges (including the solar bonus scheme costs), unlike our draft notified prices (see chapter 3).[88] By the time we make our final determination, the AER will have published its final decision, so it will then be clear whether the standing offer adjustment should be reduced.

5.2 Competition and headroom—large customers

In making a price determination, we are required to have regard to, among other things, the effect of the price determination on competition in the Queensland retail electricity market.[89]

Since the 2012–13 price determination, we have included a headroom allowance of 5 per cent of total costs to facilitate retail competition in the large customer segment in regional Queensland.

Stakeholder submissions

Cotton Australia said it was 'adamantly opposed' to the application of a 5 per cent headroom allowance. It contended that the concept is flawed and there is no evidence that competition has developed from its application.[90]

EQ noted that 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.[91]

Analysis and draft position

We consider that continuing to include a headroom allowance in notified prices is a way to promote a degree of competition in the large customer market segment in regional Queensland, because it:

- incentivises retailers to compete for customers
- encourages customers to engage in the competitive market, by seeking out more attractive offers.[92]

Since a 5 per cent headroom allowance was first included in 2012–13, competition has developed in the large customer market segment, particularly in areas where notified prices closely reflect the actual costs of supply—that is, Ergon east pricing zone, transmission region one. In this region, the proportion of large customers on market contracts is high and has been increasing. As at June 2019, 77 per cent of very large customers and 50 per cent of large customers were on market contracts in this area.[93]

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

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[88] In its draft decision, the AER said it would seek to include an allowance for these costs in its final determination of the DMO, if electricity distributors become responsible for recovering them (see AER 2020, pp. 43–44).
[89] Section 90(5)(a)(ii) of the Electricity Act.
[90] Cotton Australia, sub. 3, pp. 2, 6.
[91] EQ, sub. 4, attachment, p. 13.
[92] The inclusion of headroom to promote competition is consistent with the AEMC's 2013 advice on best practice retail regulation (see AEMC, 2013) and is consistent with the past practice of other regulators, including IPART.
[93] This statistics are based on data from Energy Queensland.

- Setting uniform notified prices means that market contracts are unlikely to be competitive or more attractive for customers in higher-cost areas of regional Queensland, where costs of supply are higher than notified prices.
- There is a risk related to switching—once large or very large customers accept a market contract, they are not allowed to access notified prices. This is likely to discourage these customers from accepting a market offer.

We consider it reasonable to conclude that our previous approach (of including a headroom allowance at 5 per cent of total costs) has promoted competition in the large customer segment in regional Queensland, especially in areas where notified prices closely reflect the costs of supply. However, given the likely barriers to competition that we identified, it is unclear whether retaining headroom will have the benefit of facilitating further competition.

Further, as the proportion of large customers on market contracts is high and has been increasing in some areas, it raises questions regarding the appropriateness of a headroom allowance in these areas. We also note that retaining a headroom allowance is not without risks, as it may serve as a coordination device among retailers and limit discounts on market contracts. Such a risk is generally regarded as a key argument against price regulation.

For the purposes of our draft determination, we propose to continue the previous approach of including a headroom allowance at 5 per cent of total costs. However, we invite stakeholders to comment on this issue, given the uncertainties raised.

5.3 Cost pass-through mechanism

Cost pass-through mechanisms are generally used by regulators to mitigate the risk that the costs allowed 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.

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 propose to do the same for this review.

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 making our final determination, 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 of the CER. The CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination.

Such an arrangement can lead to an over- or under-recovery of 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 propose to apply a cost pass-through mechanism.

Analysis and draft position

For the draft determination, ACIL Allen has updated the CER's forecast of SRES liabilities for 2020 to reflect the most recent developments in the uptake of small-scale renewable energy systems (discussed in chapter 4). This means that retailers are likely to be required to purchase more certificates, to surrender to the CER, than initially estimated—leading to an under-recovery of SRES costs for 2019–20.

Using these updated forecasts, 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 Appendix F.

Our draft position is to require a pass-through of the under-recovery of 2019–20 SRES costs into 2020–21 notified prices. We consider this to be appropriate, given that it aligns notified prices with the UTP-consistent costs of supply.

The CER is expected to determine its final 2020 SRES liabilities in March 2020. We expect to update the SRES liabilities in our final determination.

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

Scheduled phase-out date

After our 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.[94] This was in recognition of the challenges that some customers faced when adjusting to standard tariffs. The terms of the delegation require us to consider maintaining the current phase-out dates.

Stakeholder submissions

Stakeholders did not object to the current phase-out date.[95] However, 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.[96]

Analysis and draft position

Consistent with the terms of the delegation and noting stakeholder support, we intend to maintain the existing scheduled phase-out dates for obsolete tariffs. Customers have had eight years to prepare to move to standard tariff prices and structures.

EQ proposed to introduce new transitional time-of-use network tariffs to apply from 1 July 2021 (beyond the remit of this review), which mirror the structure of obsolete tariffs 62, 65 and 66. EQ proposed that these network tariffs would only be available to customers on tariffs 62, 65 and 66.[97] However, it is premature to consider the introduction of notified prices based on these network tariffs, as the AER has yet to approve these network tariffs, and we do not have a delegation to set notified prices beyond 2020–21.

[94] This phase-out date is applicable to all obsolete tariffs, except tariff 47 and 48 (which are scheduled to expire on 30 June 2022).

[95] EQ, sub. 4, attachment, pp. 13–14; Cotton Australia, sub. 3, p. 6.

[96] Cotton Australia, sub. 2, p. 2, 6.

[97] 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 2019d, pp. 21–22).

However, to best manage the transition to standard tariffs, we encourage obsolete tariff customers to engage with Ergon Retail as soon as possible.

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.[98] Where standard tariff prices reduced, we maintained obsolete tariffs at their existing price levels.

Stakeholder submissions

A number of stakeholders considered reductions in electricity costs should be passed through to customers on obsolete tariffs.

Cotton Australia said that customers on obsolete tariffs should be given relief during periods of falling prices.[99] Kalamia noted standard small business tariff usage costs have reduced while transitional tariffs have remained frozen, which further disadvantaged rural customers.[100] Similarly, QFF was disappointed that cost reductions may not be passed on to farmers on irrigation tariffs and other business tariffs.[101]

Analysis and draft position

As draft notified prices for standard tariffs are forecasted to decrease relative to 2019–20, our draft position is to maintain obsolete tariffs at existing price levels.

Our approach has been to escalate obsolete tariff prices if standard tariff prices increased, and freeze obsolete tariff prices if standard tariff prices decreased. We considered this acted to reduce the price difference between standard and obsolete tariffs, and reduce the cost advantages to customers on obsolete tariffs relative to standard tariffs.[102]

Based on analysis from Ergon Retail, some customers may be better off moving to standard tariffs.[103] 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.

Other customers may not be better off moving 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 Cotton Australia. 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.

As such, we consider our existing approach to obsolete tariff price adjustments to be appropriate and propose to freeze obsolete prices at their 2019–20 levels.

[98] 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.
[99] Cotton Australia, sub. 3, p. 7.
[100] Kalamia, sub. 5, p. 2.
[101] QFF, sub. 9, p. 2.
[102] QCA, *Regulated retail electricity prices for 2019–20*, final determination, May 2019, pp. 70–74.
[103] See Appendix G.

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.[104]

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

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.

As with the approach taken for the 2019–20 determination, we have based these metering costs on the latest confidential data provided by retailers. Our draft metering charges for large customers are set out in chapter 6.

We averaged the latest data provided by retailers to produce cost estimates for each large customer type. Overall, the latest data indicated a decrease in costs for connection asset customers and an increase in costs for standard asset and individually calculated customers.

5.7 Additional issues raised in submissions

The following table outlines our responses to additional issues raised in submissions, which have not been otherwise addressed in this draft 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 energy usage during the daytime off-peak period and takes advantage of falling solar input costs.[105] • 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).[106] • QFF said it is paramount that producers have access to tariffs that are not only cost-effective, but also	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.

[104] This scheme was closed off to new customers on 31 December 2019, and will end on 30 September 2020.
[105] ASMC, sub. 1, p. 2.
[106] Cotton Australia, sub. 3, pp. 4–5.

Stakeholder comment	***Our response***
reflect their usage, and are flexible to accommodate their business's varying usage. [107]	
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.[108]	We perform our role in accordance with the requirements of the Electricity Act and the terms of our delegation. While we note QCOSS' 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 treatment of electricity costs in our rural irrigation price review and said electricity prices should not be determined in isolation from irrigation water prices.[109]	We have considered those specific matters as part of our rural irrigation price review (2020–24). Our role in determining regional electricity prices is governed by the Electricity Act and the terms of our delegation.
National Seniors Australia (NSA) expressed concerns about the network tariff structures proposed by EQ.[110]	We note NSA has raised with the AER a number of 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.
Canegrowers made comments in relation to Energex and Ergon Distribution's network revenue and tariff proposal.[111]	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.[112] • Kalamia said before transitional tariffs expire, alternatives must be developed to meet the specific requirements for agricultural irrigation.[113]	In accordance with the delegation, we are required to consider setting notified prices using an N+R approach. The question of the appropriateness of a transition to demand-based 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.[114]	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'.[115]	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.

[107] QFF, sub. 9, p. 3.
[108] QCOSS, sub. 7, p. 2.
[109] QFF, sub. 9, p. 3.
[110] NSA, sub. 6, p. 1.
[111] Canegrowers, sub. 2, attachment, pp. 1–17.
[112] Cotton Australia, sub. 3, pp. 3–4.
[113] Kalamia, sub. 5, p. 2.
[114] EQ, sub. 4, attachment, p. 14.

6 DRAFT NOTIFIED PRICES

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

Appendix J provides a draft gazette notice, which includes the draft 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)	84.258	22.533			
Tariff 12A—residential (time of use)[b]	73.513	19.345	53.938		
Tariff 14—residential (time of use demand)[c]	47.812	15.961		6.962	48.481
Tariff 31—night rate (super economy)		17.687			
Tariff 33—controlled supply (economy)		18.178			

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)	118.424	23.236			
Tariff 22A—business (time of use)[b]	115.403	21.917	52.605		
Tariff 24—business (time of use demand)[c]	65.082	16.900		6.716	66.835
Tariff 41—low voltage (demand)	480.741	15.339		18.593	
Tariff 91—unmetered		20.700			

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—over 100 MWh small (demand)	4225.998	12.376		27.449		24.704
Tariff 45—over 100 MWh medium (demand)	13745.719	12.376		21.806		19.626
Tariff 46—over 100 MWh large (demand)	35836.128	12.376		17.886		16.097
Tariff 50—over 100 MWh seasonal time-of-use (demand)[b]	3540.376	14.394	12.038	11.020	70.035	
Tariff 71—street lighting		25.803				

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***	***Connection unit***	***Capacity***	***Demand charge***
	c/day	***c/kWh***	***$/day/unit***	***$/kVA of AD/mth***	***$/kVA/mth***
Tariff 51A—over 4 GWh high voltage (CAC 66 kV)	26032.355	11.945	8.408	3.690	3.190
Tariff 51B—over 4 GWh high voltage (CAC 33 kV)	18805.205	11.945	8.408	4.523	3.305
Tariff 51C—over 4 GWh high voltage (CAC 22/11 kV Bus)	17617.445	11.945	8.408	5.226	4.006
Tariff 51D—over 4 GWh high voltage (CAC 22/11 kV Line)	16938.725	11.945	8.408	10.194	8.084
Tariff 53—over 40 GWh high voltage (ICC)	25838.900	11.945		3.690	3.190
ICC site-specific—over 40 GWh high voltage	3712.200	10.686		0.376	0.325

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)—transitional	76.858					37.595		
Tariff 21—transitional		72.631	49.357	46.374	35.303			
Tariff 22 (small and large)—transitional	184.717		49.820		17.543			
Tariff 37[d]—obsolete		30.623	21.807		54.544			
Tariff 62—transitional	78.451		46.516	39.336	16.448			
Tariff 65—transitional	78.003		36.894		20.321			
Tariff 66—transitional	171.915					19.338	37.503	112.759

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