Queensland Competition Authority

Draft determination

# Regulated retail electricity prices in regional Queensland 2022–23

**February 2022**

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# Submissions

**Closing date for submissions: 7 April 2022**

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (QCA). Therefore, submissions are invited from interested parties concerning its assessment of regulated retail electricity prices for regional Queensland in 2022–23. 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.

# WHAT HAVE WE BEEN ASKED TO DO?

On 16 December 2021, we received a delegation from the Minister for Energy, Renewables and Hydrogen (the Minister) to set regulated retail electricity prices (notified prices) to apply in regional Queensland in 2022–23. The delegation was issued in accordance with s. 90AA of the Electricity Act 1994 (Qld).

## Scope of the review

The purpose of our review is to determine notified prices for 2022–23. In accordance with the requirements in the Electricity Act, the factors[1] we must have regard to when making a price determination 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.[2]

## Matters we must consider under the delegation

The Minister's delegation includes a terms of reference setting out matters relevant to this price determination, including:

- the period—the price determination applies from 1 July 2022 to 30 June 2023
- the timeframes—we must publish the draft determination by the end of February 2022, and the final determination by the end of May 2022
- particular policies or principles—we must have regard to, among other matters, the Queensland Government's Uniform Tariff Policy (UTP)
- the pricing methodology—we must set notified prices having regard to the network plus retail (N+R) cost build-up methodology
- consultation—we must consult at various stages before we make the final price determination.

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

[1] Electricity Act, s. 90(5)(a).
[2] Electricity Act, s. 90(5)(b).

# CONTENTS

# 1 ABOUT OUR REVIEW: PROCESS AND TIMING

## 1.1 Draft determination

This draft determination contains draft notified prices, presented as bundled prices appropriate to the retail tariff structure (except for site-specific tariffs).[3] In making this draft determination, we have had regard to relevant factors in the Electricity Act, matters in the delegation, stakeholder submissions on the interim consultation paper (ICP)[4], and our own analysis.

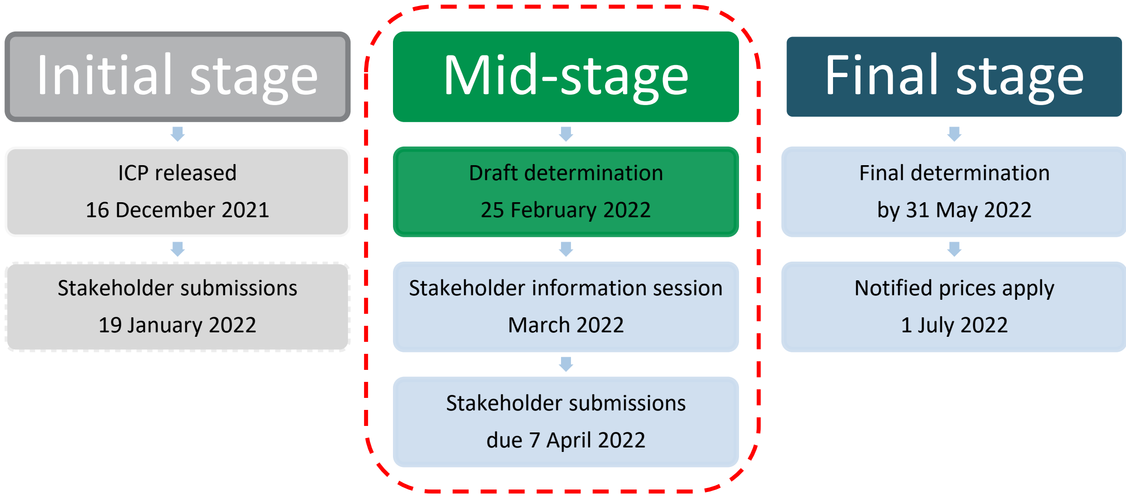
Stakeholders are invited to provide comments on our draft determination via written submissions. Information on making a submission is available on our website.[5]

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

**Submissions on the draft determination are due by 7 April 2022.**

## 1.2 Key dates

We are currently midway through the review process. The key review dates, including when we intend to publish our final determination, are provided below.




We encourage stakeholders to subscribe to our email alerts to keep up to date with the latest developments on this project.

[3] As required in cl. 8 of the Schedule in the terms of reference (Appendix A).
[4] We received 7 submissions in response to our interim consultation paper. These are available on our website and listed in Appendix B.
[5] Our submission policy and online submission form are available on our website.

## 1.3 Human Rights Act declaration

As required by the *Human Rights Act 2019* (Qld) (s. 58), we have considered the compatibility of our determination with human rights. Our determination relates to the prices that individuals, as consumers, pay for the supply of electricity; therefore, we consider the following human rights may potentially be relevant:

- equality and non-discrimination
- protection of families and children.

When setting notified prices, we have had regard to, among other things, the Queensland Government's UTP, which provides that:

> wherever possible, customers of the same class should pay no more for their electricity, and should pay for their electricity via similar common price structures, regardless of their geographic location.[6]

Because of this policy, the electricity prices for most customers in regional Queensland are set at a cost below the actual cost of supply. The above-mentioned rights have therefore not been limited by our decision.

We are of the view this draft price determination is compatible with human rights under s. 8(a) of the Human Rights Act.

## 1.4 Report structure

This draft determination is structured as follows:

- Indicative customer bill impacts (chapter 2)
- Overarching framework—including our approach for setting prices (chapter 3)
- Cost build-up components—individual cost elements (chapter 4)
  - Network component (section 4.1)
  - Retail component (section 4.2)
- Other costs and pricing issues (chapter 5)
- Draft notified prices (chapter 6).

### Supporting documents

#### Information booklet

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

#### Consultant's report

We engaged ACIL Allen to assist us in setting the energy cost component of notified prices this year (ACIL Allen's report is discussed in section 4.2.1).[7]

[6] As required in cl. 1(a) of the Schedule in the terms of reference (Appendix A).
[7] ACIL Allen's report has been published on our website.

### Technical appendices

Supporting information is provided in the following appendices:

- Appendix A: Minister's delegation
- Appendix B: Stakeholder submissions and references
- Appendix C: Energy cost approach
- Appendix D: Cost pass-through approach
- Appendix E: Data used to estimate customer impacts
- Appendix F: Build-up of draft notified prices
- Appendix G: Draft gazette notice.

# 2 INDICATIVE BILL IMPACTS

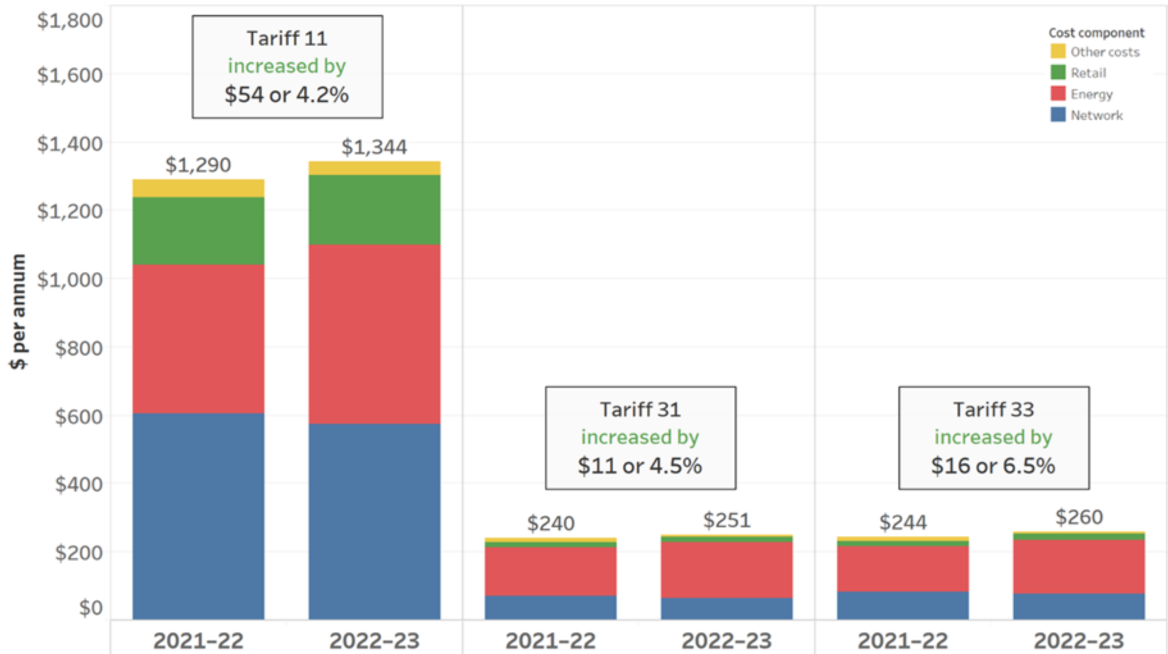
Overall, typical customers[8] on all major tariffs can expect an increase in their electricity bill this year, based on the draft notified prices.[9] The increase is largely due to an increase in estimated energy costs.[10] The charts we provide show bills for a typical customer based on the draft notified prices, compared to bills based on the current (2021–22) notified prices.

Importantly, an individual customer's actual bill will vary depending on how much electricity they use. We strongly recommend that customers engage with their retailer for further advice and information reflecting their individual circumstances.

## 2.1 Residential customers

Typical customers on the main residential tariffs (tariffs 11, 31 and 33)[11] are expected to pay around 4.2 to 6.5 per cent more for their electricity in 2022–23 (see figure below).[12]

**Figure 2.1 Bills for typical residential customers, 2021–22 and 2022–23 (incl. GST)**



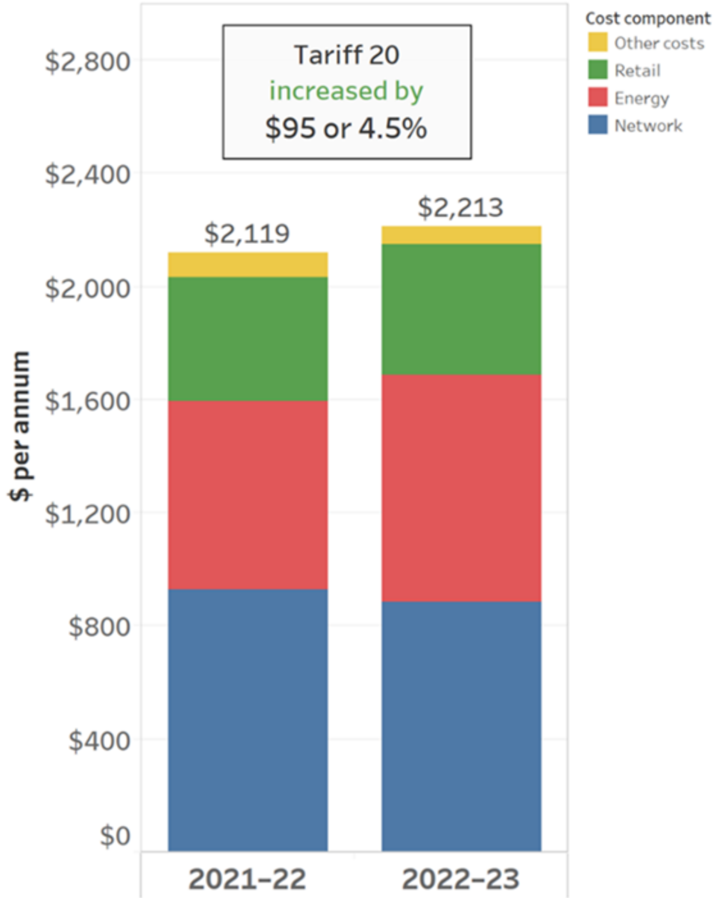

*Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.*

[8] 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 E).
[9] The draft notified prices are set out in chapter 6.
[10] Individual cost components of notified prices are discussed in chapter 4.
[11] Most residential customers are on tariff 11, but many customers also access load control tariffs—tariffs 31 and 33—for appliances that do not require a constant supply of electricity (e.g. hot water systems and pool pumps).
[12] Metering charges are excluded from the bill impact analysis due to the variety of different metering arrangements that a customer may have.

## 2.2 Small business customers

Typical customers on the main small business tariff (tariff 20)[13] are expected to pay around 4.5 per cent more for their electricity in 2022–23 (see figure below).[14]

**Figure 2.2 Bills for typical small business customers, 2021–22 and 2022–23 (incl. GST)**




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

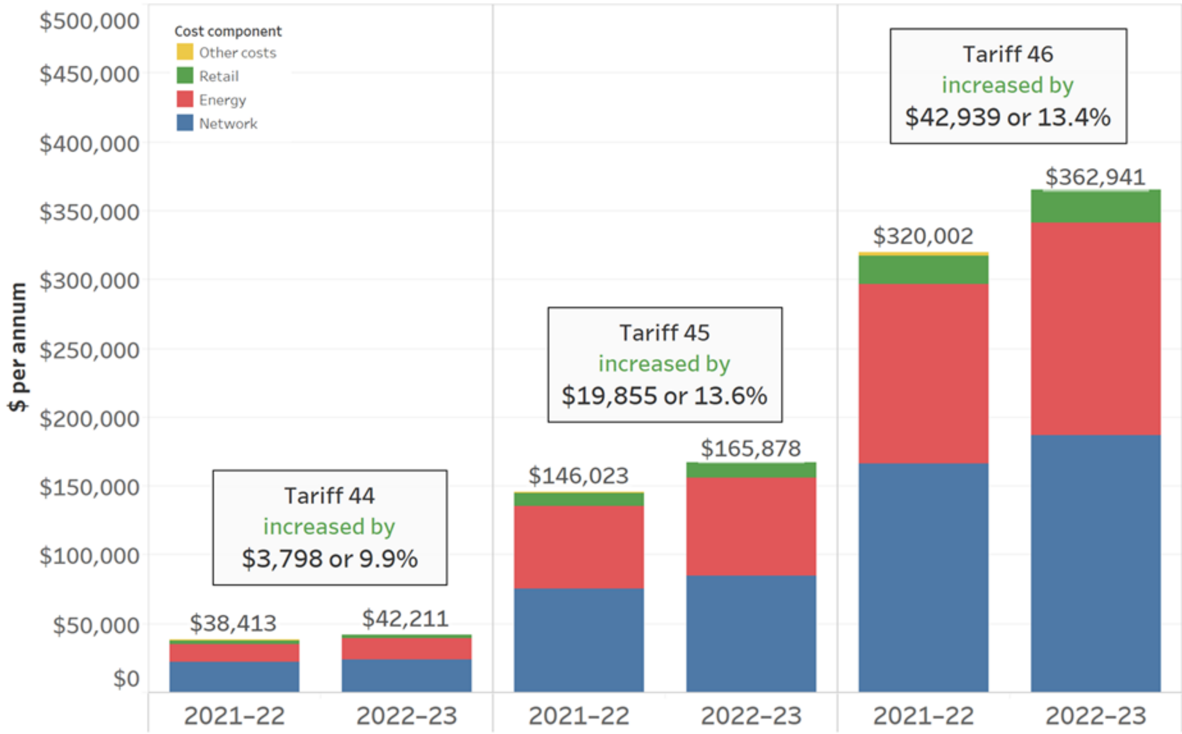
[13] Tariff 20 is a flat-rate tariff.

[14] Metering charges are excluded from the bill impact analysis due to the variety of different metering arrangements that a customer may have.

## 2.3 Large business customers

Typical customers on tariffs 44, 45 or 46 are expected to pay around 9.9 to 13.6 per cent more for their electricity in 2022–23 (see figure below).[15]

**Figure 2.3 Bills for typical large business customers, 2021–22 and 2022–23 (incl. GST)**




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

[15] Metering charges are excluded from the bill impact analysis due to the variety of different metering arrangements that a customer may have.

# 3 OVERARCHING FRAMEWORK

This chapter provides our draft views on key issues we have considered in this year's price determination, including overarching matters that determine the cost level and availability of tariffs for notified prices. Many of these are identified in the Minister's delegation (and terms of reference), which we must consider when setting notified prices.

We have been asked to consider a few new issues this year, including reviewing the tariff schedule to remove any tariffs no longer considered appropriate, as well as some emerging issues in the electricity market (e.g. relating to electric vehicle tariffs).

## 3.1 Our approach to setting notified prices

The delegation is largely consistent with previous years, and our approach to setting notified prices is also largely consistent to that used in previous price determinations. Our draft position is to continue to apply the same broad approach to setting notified prices, which includes applying the uniform tariff policy and using the N+R cost build-up methodology.

### Uniform tariff policy

The Queensland Government's uniform tariff policy (UTP) provides that, wherever possible, customers of the same class should pay no more for their electricity and should be able to pay for their electricity via similar common price structures, regardless of their geographic location.

The UTP benefits customers in regional Queensland, because notified prices for most customers are set at a lower level than their actual costs of supply. The cost difference is met by the Queensland Government through the payment of a community service obligation subsidy to Ergon Energy Queensland of approximately $500 million each year.[16]

In previous determinations, we applied the UTP by:

- basing notified prices for residential and small business customers on the cost of supply in south east Queensland (SEQ)
- basing notified prices for large business customers on the cost of supply in the Ergon region with the lowest cost of supply that is connected to the NEM[17]
- maintaining existing retail tariffs (including those without underlying network tariffs) and introducing 15 new retail tariffs (underpinned by newly introduced network tariffs).

Our draft position is to continue to apply this approach in terms of cost levels, but we have reviewed the current suite of retail tariffs and propose to remove some tariffs no longer considered appropriate (see section 3.2.1).

### N+R methodology

When setting notified prices, the delegation requires us to consider using the N+R cost build-up methodology. In previous price determinations, we applied the N+R methodology by passing through the network costs (the N component) and estimating energy and retail costs (the R

[16] Queensland Government, *Queensland Budget 2021–22, Budget Strategy and Outlook*, Budget Paper No. 2, June 2021, p. 35.
[17] This is the Ergon Distribution east zone, transmission region one.

component) for each tariff. We then applied a standing offer adjustment to small customer notified prices to reflect the additional value and protections of terms and conditions in standard contracts (see chapter 5.1).

Stakeholders generally supported the continued use of the N+R methodology to set notified prices.[18] Ergon Energy Retail (EER) said to meet customer needs in future, this approach could be adjusted so that retail tariffs do not necessarily mirror the structure and conditions of network tariffs. Other stakeholders raised a number of matters in the context of the N+R methodology that are outside the scope of our review—these are discussed in section 5.4.

Our draft position is to apply the N+R methodology to set notified prices for retail tariffs in the same manner as in the past, passing through the N components based on the network prices and our estimates of the R components. Further details regarding the individual components that make up retail tariffs are discussed in chapters 4 and 5.

If the delegation required us to consider changes to the N+R methodology (such as those suggested by EER) we could do so based on the guidance provided. For instance, in the past, the delegation has required us to consider specific departures from the standard N+R methodology under specific circumstances—that is, to set retail tariffs that no longer had an underlying network tariff on which to base the notified price, as well as to set different terms and conditions for retail tariffs than those applied at the network level. However, without such guidance, we consider it appropriate to set prices based on the longstanding N+R approach, which is consistent with the Electricity Act, well known and provides ongoing certainty to stakeholders on how prices will be set.

## 3.2 New pricing matters

We have been asked to consider some new issues this year, namely the rationalisation of existing retail tariffs, and some emerging issues relating to electricity pricing for electric vehicles.

### 3.2.1 Tariff rationalisation

The delegation asks us to review existing retail tariffs with a view to:

- removing any tariffs no longer considered appropriate
- introducing suitable transitional arrangements for any customers impacted by the removal of tariffs.[19]

The Minister provided the following further context and guidance:

> The QCA should consider if individual tariffs are meeting customer needs, and balance competing factors including the impact extinguishing a tariff would have on customers and their options, along with other matters the QCA considers relevant. Consistent with [the] application of the [uniform tariff policy], this should be informed by the price structures commonly available in the deregulated [south east Queensland] electricity market and with a view to future needs for a variety of tariffs to be available as customer preferences, needs and technologies change.[20]

[18] EER, sub. 5, p. 5; Ergon Energy Network and Energex, sub. 4, p. 2.
[19] Appendix A: Minister's delegation, terms of reference, para 2(b).
[20] Appendix A: Minister's delegation, covering letter, p. 2.

The Minister also considered the existing flat rate and controlled load tariffs for both residential and small business customers should be retained, and careful consideration should be given to retaining any tariffs compatible with the uptake of EVs and other technologies in future.[21]

### Stakeholder comments

Overall, stakeholders supported reviewing the retail tariffs to better reflect customer needs:

- EER said it is important for customers to have choices, but the level of choice should not be so overwhelming to create inertia and a lack of engagement around choosing the most appropriate retail tariff for their home or business.[22]
- Ergon Energy Network (EEN) and Energex said there is 'merit in rationalising the number of regulated retail tariffs where the economic benefit does not exceed the ongoing costs associated with the continued existence of the tariff.'[23]

Some stakeholders raised particular matters they considered relevant to our assessment:

- EER, EEN and Energex supported removing retail tariffs that do not have an underlying network tariff.[24]
- EER said we should consider tariffs that send appropriate price signals to customers, noting some existing tariffs with outdated peak charging windows disincentivise usage at times of low demand or high solar (which is not in the best interests of customers (over the long term) or the energy sector).[25]
- EEN and Energex said any retail tariffs based on existing network tariffs that play a critical role in their network tariff strategy should not be removed.[26]
- Cotton Australia considered there may be room for rationalising some tariffs but said there needs to be a process 'over-and-above' this determination to fully test whether some tariffs meet customer needs.[27]

### Analysis and draft position

The current suite of tariffs has evolved over time, reflecting both policy and market factors. For instance, in the last two years we have been directed to set various new retail tariffs based on new network tariffs arising from the recent network reforms, with the view to providing regional customers with greater tariff options and more cost-reflective price signals.

While we set prices, unlike retailers, we do not have access to detailed customer information to assess the suitability of tariffs to meet customer needs and circumstances, nor can we alter network tariffs to offer retail tariffs suggested by stakeholders. Consistent with our pricing framework, we consider it appropriate:

- to set tariffs using the N+R cost build-up approach (basing the retail tariffs on the relevant network tariffs)—the use of this approach is set out in the Minister's delegation and is an important feature of our price setting process. It is therefore relevant to consider as part of

[21] Appendix A: Minister's delegation, covering letter, p. 3.
[22] EER, sub. 5, p. 6.
[23] Ergon Energy Network and Energex, sub. 4, p. 1.
[24] EER, sub. 5, pp. 6–7; Ergon Energy Network and Energex, sub. 4, p. 1.
[25] EER, sub. 5, p. 4.
[26] Ergon Energy Network and Energex, sub. 4, p. 1.
[27] Cotton Australia, sub. 3, p. 2.

the tariff rationalisation review. We have applied a 'flexible N+R' approach in recent price determinations, using an indexation to determine tariff prices that do not have an underlying network tariff. However, this approach may not be feasible in the longer term (which is a relevant consideration for this process).

- to consider the Queensland Government's UTP, including whether the retail tariff is commonly offered in SEQ—as we have had regard to the government's UTP when setting prices, it is relevant to have regard to the tariffs offered in SEQ as part of this process.

In conducting our review of the retail tariff schedule, we have also considered matters in the delegation and other factors that may be relevant, such as:

- customer needs and tariff options—the tariff schedule should maintain an appropriate range of tariff options to meet the needs of customers. However, providing too many tariff options (particularly of the same tariff type) can be counter-productive and may make it more difficult for customers to assess their options and switch to alternative tariffs. For example, having multiple different peak windows among TOU tariffs adds complexity to the tariff schedule. We consider it more important for a customer to have choices between different tariff types than between different tariffs of the same tariff type
- customer uptake of the retail tariff (based on the number of national metering identifiers (NMIs)[28] assigned to the tariff)[29]—while this consideration is informative, it has not been determinative in our position to rationalise certain tariffs. It is balanced against other considerations, including the N+R framework
- customer impact—providing a transition period to allow any customers who are impacted to assess options and decide a suitable replacement tariff.

Having regard to the relevant factors, stakeholder comments and our own analysis, we have formed draft views on rationalising the existing suite of retail tariffs and propose to:

- make six tariffs obsolete[30] and
- extinguish[31] a further tariff (all from 1 July 2022).

Importantly, making a tariff obsolete provides a transition period for existing customers on that tariff to assess their options before they lose access to the tariff. While most are small customer tariffs, we consider the remaining tariffs provide an appropriate level of choice for small customers, including because each customer class will continue to have access to flat rate, time of use (TOU), demand and controlled load tariff types.

Table 3.1 provides an overview of our draft position on each tariff. Further detail on our positions on particular tariffs is provided below. We seek stakeholder feedback on our draft positions, and particularly customer and retailer views on tariffs we propose to make obsolete or extinguish, as well as the proposed phase-out periods.

[28] A national metering identifier is an individual reference number used to identify a connection point to the national electricity market. Every connection to the national electricity network is given its own NMI.
[29] This is based on data provided to us by Ergon Energy Retail as at December 2021.
[30] When a tariff is made obsolete, it means the tariff can no longer be accessed by new customers. Customers who are on the tariff immediately before it is made obsolete can continue to access the tariff until the tariff's scheduled phase-out date. A customer that moves off an obsolete tariff cannot access the obsolete tariff again.
[31] Extinguishing a tariff means the tariff is immediately removed from the tariff schedule and any existing customers on that tariff need to be transferred to another tariff.

**Table 3.1 Overview of our draft position on the rationalisation of the retail tariff schedule**

| ***Residential tariff*** | ***Draft position*** | ***Large customer tariff*** | ***Draft position*** |
|---|---|---|---|
| Tariff 11 (flat rate) | Retain | Tariff 43 (inclining block) | Retain |
| Tariff 12A (seasonal TOU) | Make obsolete | Tariff 44 (monthly demand – 30 kW/35 kVA threshold) | Retain |
| Tariff 12B (TOU) | Retain | Tariff 45 (monthly demand – 120 kW/135 kVA threshold) | Retain |
| Tariff 14 (seasonal TOU monthly demand) | Make obsolete | Tariff 46 (monthly demand – 400 kW/450 kVA threshold) | Retain |
| Tariff 14A (TOU monthly demand) | Retain | Tariff 50 (seasonal TOU monthly demand) | Make obsolete |
| Tariff 14B (TOU monthly demand) | Retain | Tariff 50A (TOU monthly demand) | Retain |
| ***Residential and small business load control tariff*** | ***Draft position*** | Tariff 51A (CAC supplied at 66 kV) | Retain |
| Tariff 31 (small customer secondary load control) | Retain | Tariff 51B (CAC supplied at 33 kV) | Retain |
| Tariff 33 (small customer secondary load control) | Retain | Tariff 51C (CAC supplied on an 11 or 22 kV bus) | Retain |
| ***Small business tariff*** | ***Draft position*** | Tariff 51D (CAC supplied on an 11 or 22 kV line) | Retain |
| Tariff 20 (flat rate) | Retain | Tariff 52A (CAC seasonal supplied at 33 or 66 kV) | Retain |
| Tariff 20A (inclining band) | Extinguish | Tariff 52B (CAC seasonal supplied on 11 or 22 kV bus) | Retain |
| Tariff 22A (seasonal TOU) | Make obsolete | Tariff 52C (CAC seasonal supplied on 11 or 22 kV line) | Retain |
| Tariff 22B (TOU inclining band) | Retain | Tariff 53 (ICC) | Retain |
| Tariff 24 (seasonal TOU monthly demand) | Make obsolete | ICC site-specific | Retain |
| Tariff 24A (TOU monthly demand) | Retain | Tariff 60A (large business primary load control) | Retain |
| Tariff 24B (TOU monthly demand) | Retain | Tariff 60B (large business secondary load control) | Retain |
| Tariff 34 (primary load control) | Retain | ***Unmetered supply tariffs*** | ***Draft position*** |
| Tariff 41 (monthly demand) | Make obsolete | Tariff 71 (flat rate for street lighting) | Retain |
| ***Obsolete tariffs (excl. tariff 50) would be phased out on 30 June 2023. The tariff 50 phase-out date would be aligned with the network tariff phase-out date.** | | Tariff 91 (business flat rate) | Retain |

### Small customer seasonal tariffs (tariffs 12A, 14, 22A and 24)

Tariffs 12A and 22A are seasonal TOU tariffs,[32] while tariffs 14 and 24 are seasonal TOU demand tariffs.[33] These tariffs no longer have underlying network tariffs following the recent network tariff reforms and the introduction of new small customer TOU and demand tariffs.

EER, and EEN and Energex supported removal of these tariffs, while Cotton Australia questioned how the structure of tariff 22A compared with the structure of other TOU tariffs.[34]

Our draft position is to make these tariffs obsolete and to set a scheduled phase-out date of 30 June 2023 (12 months), on the basis that:

- there are no underlying network tariffs, so maintaining these tariffs as standard tariffs in the long term is not consistent with the N+R framework
- there are other tariffs of a similar nature available to small customers (i.e. TOU and demand tariffs). While these other tariffs do not have the seasonal element, that element has been phased out at the network level for small customer tariffs, so it is not clear why the seasonal element should be retained at the retail level. We are mindful that having multiple TOU and demand tariffs for a customer class, with different peak windows, creates complexity in the tariff schedule and may deter a customer from moving onto these tariff types. We consider it preferable to retain the peak windows of the more recently introduced tariffs (e.g. 4 pm to 9 pm), as these windows have been more recently developed and align with the network tariff strategy
- these tariffs have a relatively low uptake, as all but one of these tariffs have less than 200 NMIs assigned to them (tariff 24 has less than 750 NMIs assigned to it).

EER, and EEN and Energex proposed a 12-month phase-out date for each of these tariffs.[35] We consider this timeframe is reasonable. However, we seek stakeholder views on whether this timeframe should be made longer, particularly for tariff 24, due to the higher number of affected customers on this tariff. For example, we are interested in whether a longer transition period is desirable due to customers having made investments, or otherwise structured their business, to take advantage of these tariff structures or if further time is needed for affected customers to assess the suitability of alternative tariffs.

### Small customer TOU demand tariffs (tariffs 14A, 14B, 24A and 24B)

Tariffs 14A and 14B are TOU demand tariffs for residential customers. They each have the same tariff structure, but tariff 14A is based on the residential transitional demand network tariff, while tariff 14B is based on the residential demand network tariff.[36] Tariffs 24A and 24B are also TOU demand tariffs but apply to small business customers. Similar to the residential tariffs, tariff 24A is the transitional tariff variant.

[32] These tariffs have a peak usage charge for consumption during certain times in summer months. Tariff 12A is a residential tariff and tariff 22A is a small business tariff.

[33] These tariffs have a peak demand charge that is calculated based on consumption during certain times in summer months. Tariff 14 is a residential tariff, and tariff 24 is a small business tariff.

[34] EER, sub. 5, pp. 6–7; Ergon Energy Network and Energex, sub. 4, p. 1; Cotton Australia, sub. 3, p. 2.

[35] EER, sub. 5, pp. 6–7; Ergon Energy Network and Energex, sub. 4, p. 1.

[36] The difference between these tariffs is that tariff 14A has a lower demand charge but higher usage and daily supply charges compared to tariff 14B.

The transitional tariff variants are intended to 'limit the network cost impact on customers reassigned to cost reflective tariffs and assist customers transition to and gain greater comfort regarding demand tariffs.'[37]

Stakeholders had mixed views on whether we should retain these tariffs:

- EER said the transitional tariff variants (T14A and T24A) should be removed, because customer uptake is low, and these customers should be transitioned to the demand tariff (T14B or T24B), the preferred demand structure and pricing of the Queensland distributors.[38]
- EEN said they do not support removal of any of these retail tariffs, indicating the underlying network tariffs play a critical role in their network tariff strategy based on the following:
  - There are approximately 161,284 customers in regional Queensland on the transitional network tariff,[39] which they said will increase significantly in future as basic accumulation meters continue to be replaced or upgraded over time.
  - While there are approximately 100 customers on the residential demand tariff, they expect this number will grow over time. They also argued that retaining the associated retail tariff provides customers with a choice of cost-reflective tariff structures and supports their future strategy.[40]

We acknowledge having two similar demand tariffs within a customer class adds complexity to the tariff schedule and to a customer's evaluation of which demand tariff variant is better for them. This level of choice could act as a barrier to the uptake of a demand tariff. However, we consider there are merits in retaining both tariff variants:

- Consistency with the N+R framework—we are mindful that all of these tariffs have been developed by EEN and having both tariff variants available to customers forms part of their tariff strategy; a strategy which has been approved by the Australian Energy Regulator (AER). On this point, EEN has stated the retail tariffs based on these network tariffs should not be phased out. With that in mind, we consider these tariffs should continue to be made available at the retail level.
- For the transitional demand tariff variant (tariffs 14A/24A):
  - given the uptake of demand tariffs is still low, there is benefit in retaining this tariff, as it has been designed to ease the transition of customers to a demand tariff structure
  - the transitional demand tariffs are the default network tariffs for new customers and existing customers who have a smart meter (or whose basic meter is upgraded to a smart meter).[41]
- For the other demand tariff variant (tariffs 14B/24B)—as we are phasing out the other demand tariffs (tariffs 14, 24 and 41), if we do not retain these, the tariff schedule will not have a small customer demand tariff with a standard demand charge (full price signal). This

[37] Energex, *Energex TSS Explanatory Notes 2020–2025*, December 2019, p. 32.
[38] EER, sub. 5, pp. 6–7.
[39] While customers pay a retail tariff to their retailer, the customer is also assigned to a network tariff, which the retailer pays to the distributor. A customer's retail tariff and the network tariff to which the customer is assigned may not align. The reasons why the tariffs might not align can be due to the retail tariff being different to the tariffs available at the network level and default network tariff assignments.
[40] Ergon Energy Network and Energex, sub. 4, pp. 1–2.
[41] Energex, *Energex Tariff Structure Statement 2020–2025*, June 2020 (erratum August 2020), pp. 18, 20, 21.

will deny customers the opportunity to move onto a standard demand tariff, including customers currently on one of the other demand tariffs to be phased out who have already demonstrated a willingness to adopt a demand tariff. We consider customers should have this opportunity.

We also consider the potential customer confusion caused by having both tariff variants may be reduced given we are proposing to phase out all the other small customer demand tariffs. This should make it easier for retailers to communicate these two demand tariff variants to their customers.

In light of the above, our draft position is to retain both tariff variants in each customer class (i.e. retain tariffs 14A, 14B, 24A and 24B).

### Tariff 20A

Tariff 20A is an inclining band tariff for small business customers.[42] This tariff was added to the tariff schedule on 1 January 2021, following its introduction at the network level as part of the network tariff reforms.

EER said we should remove this tariff as no customers have adopted it (or are likely to) due to the high fixed charges and because it has the same usage rate as tariff 20 (small business flat rate tariff).[43] Similarly, Cotton Australia questioned the value provided by tariff 20A compared to tariff 20.[44] EEN and Energex said they did not support removal of any retail tariffs that are based on existing network tariffs that play a critical role in their network tariff strategy,[45] although it is unclear whether they consider the underlying network tariff for tariff 20A plays such a role.

Our draft position is to remove tariff 20A from the tariff schedule. While this tariff does have an underlying network tariff, this retail tariff is not being used by customers. Also, it is not clear the circumstances in which a customer would opt-in to this tariff at the retail level over tariff 20. As such, it is not apparent this tariff provides value to customers at the retail level, and we consider it should be removed.

We propose to extinguish tariff 20A (which means there will be no transition period for this tariff). This is because there are no customers on this tariff (based on the latest information available to us). Also, if customers do opt-in to this tariff prior to our final determination, they could be reassigned by retailers to tariff 20, which should not have an adverse impact on them. However, we seek stakeholder views on whether tariff 20A should have a phase-out period similar to the other tariffs we propose to rationalise.

### Tariff 41

Tariff 41 is a small business demand tariff. Since 2016–17, we based the N component of this tariff on an Energex large customer demand tariff (NTC 8300). This was on the basis that while it is a large customer tariff, it was made available to small business customers on a voluntary basis. However, under Energex's 2020–25 tariff structure statement (TSS), this network tariff is no longer available to small business customers. In our 2020–21 price determination, we decided to

[42] This tariff has a flat-rate usage charge and a daily supply charge that has five inclining bands based on annual consumption.
[43] EER, sub. 5, p. 7.
[44] Cotton Australia, sub. 3, p. 2.
[45] Ergon Energy Network and Energex, sub. 4, p. 1.

maintain these arrangements for tariff 41 and consider this matter in a future price determination.[46]

EER said tariff 41 should be grandfathered and given a 12-month phase-out period. It considered there is no need for this tariff, because there is an alternative demand tariff that has been developed specifically for small business customers and that has a preferable peak period of 4 pm to 9 pm.[47]

Our draft position is to make this tariff obsolete and set a scheduled phase-out date of 30 June 2023 (12 months), on the basis that:

- phasing out this tariff is consistent with the N+R framework we use to set prices. While we have used an Energex network tariff to derive the N component for this tariff, tariff 41 does not have an underlying network tariff that is directly comparable to it (i.e. for the small business customer class)
- there are alternative demand tariffs that have been specifically developed for small business customers (tariff 24A/24B). We acknowledge that tariff 41 has a flat (anytime) demand charge as opposed to the TOU demand charge used in those alternative tariffs. However, the use of a TOU demand charge reflects the approach taken for small business customers at the network level. It is not apparent to us that there is a need to maintain this flat demand charge option
- this tariff has a relatively low uptake—under 200 NMIs are assigned to this tariff.

We propose a 12-month phase-out date for this tariff. However, we seek stakeholder views on whether this timeframe should be made longer, particularly if affected customers have made investments, or otherwise structured their business, to take advantage of this tariff structure.

#### Tariff 50

Tariff 50 is a large customer seasonal TOU monthly demand tariff.[48] The underlying network tariff for tariff 50 was grandfathered (closed to new customers) from 1 July 2020 as part of EEN's 2020–25 tariff schedule statement (TSS).[49] However, tariff 50 has remained a standard retail tariff that is available to new customers.

EER said customers accessing tariff 50 require certainty around the longevity of this retail tariff, and we should provide guidance around our intentions for this tariff.[50] However, customers did not raise this as an issue.

To provide consistency with the network tariff arrangements, our draft position is to make tariff 50 obsolete, so that no new customers can access the tariff. Customers have access to similar types of tariffs, such as tariff 50A (a TOU monthly demand tariff) and the large customer anytime demand tariffs (e.g. tariff 44).

At this stage, we are not able to set a scheduled phase-out date for this tariff. We appreciate that existing customers on this tariff would want certainty about how long they will be able to access this tariff, but ultimately this will be influenced by how long it will be maintained at the network-level. The network tariff is in place for the remainder of EEN's regulatory control period (until 30 June 2025), but it is not clear whether this will be maintained into the next regulatory period. This

[46] QCA, *Regulated retail electricity prices for 2020–21: regional Queensland*, final determination, June 2020, p. 46.
[47] EER, sub. 5, p. 7.
[48] This tariff has peak demand and usage charges, based on consumption in summer months.
[49] Ergon Energy, *Ergon Energy Tariff Structure Statement 2020–2025*, June 2020 (erratum August 2020), pp. 26–27.
[50] EER, sub. 5, p. 7.

is similar to the approach we took for the limited-access obsolete retail tariffs (tariffs 62A, 65A and 66A), where there is also uncertainty over the expiry date for their underlying network tariffs.

We can consider a phase-out date for tariff 50 in a future determination (if we are delegated the task in the future), once there is greater certainty about the future of the underlying network tariff.

### 3.2.2 Emerging issues: electric vehicle (EV) electricity pricing

In the cover letter to the delegation[51], the Minister said the statewide rollout and integration of electric vehicles (EVs) into Queensland is a key focus of the Queensland Government's upcoming 10-year Energy Plan and the Zero Emissions Vehicle Strategy—pricing, infrastructure, network impacts and access to EVs will be considered as part of these strategies:

> Charging is set to introduce new load into the system and EV users will make decisions that will impact the electricity network in new ways. Uptake of EVs is growing quickly and Queensland wants to encourage this uptake in a sustainable way that limits adverse impacts on the system.[52]

The Minister said the department is working closely with electricity distributors to ensure the 'right mix of network tariffs are in place, from which regulated retail tariffs will be developed for regional Queensland'.

In addition, as part of this review, the Minister asked us to consider how tariffs could be structured to better guide customer behaviour, which may include commentaries about the need for new tariffs with different structures to those currently available and also incentives for customers to respond to stronger pricing signals within tariffs.

In particular, the Minister raised the prospect of a TOU retail tariff with improved price signals—specifically, existing retail tariff 12B (the 'solar-soaker' tariff), which has an inexpensive daytime off-peak network component. However, the energy cost component is flat across all time periods which does not reflect actual underlying energy cost structures as these vary across the day.

The Minister has not asked us to introduce new retail tariffs for EVs at this stage but indicated we might be issued a separate delegation to do so in the future.

#### Stakeholder comments

Stakeholders did not consider this is a critical issue at this time but said work on EV tariffs should begin as EV uptake is increasing. In particular:

- Energy Queensland (EQ) said the residential and small business tariffs that commenced 1 July 2020 are suitable for electricity market participants to appropriately manage EV charging in the context of forecast EV volumes over the regulatory control period (2020–25).[53]
- EEN and Energex[54] said:
  - the existing suite of network tariffs are not sufficiently cost-reflective to incentivise customers to charge their EV at optimal times—EV tariffs should be designed so customers pay less to charge EVs during off-peak times and pay a higher price to charge during the peak period

[51] Appendix A: Minister's delegation, covering letter.
[52] Appendix A: Minister's delegation, covering letter.
[53] Ergon Energy Network and Energex, *Network Electric Vehicles Tactical Plan: Summary*, October 2020, p. 9.
[54] EEQ, sub. 4, p. 3.

  - specific EV network tariffs are likely to be a focus/developed for the next AER regulatory period (2025–30), however it is not possible to introduce new (or amend existing) network tariffs before then
  - existing load control tariffs (31 and 33) offer a convenient option for customers who do not want to actively manage their network usage, including because it incentivises off-peak consumption and can already be used by EV owners.
- Canegrowers, Bundaberg Regional Irrigation Group (BRIG) and EER were in favour of retail tariffs sending stronger price signals throughout the day, including by having lower off-peak usage charge than were currently included in the existing TOU retail tariffs to encourage greater consumption during the middle of the day.[55]
- EER said we could introduce a time-varying wholesale energy component for TOU tariffs to reflect low wholesale energy costs during the day but did not suggest what this would look like or provide a detailed proposal.[56]
- Cotton Australia said the development of a new EV tariff must not require other tariff users to subsidise any additional network and/or retail costs that may be associated with an EV-specific tariff.[57]

## Analysis

We understand the importance of EV pricing in the context of the Queensland Government's broader energy and EV initiatives, including to ensure suitable tariff options are in place to encourage EV customers (particularly as EV uptake increases) to make the most of renewable energy charging options when they try to meet their increasing electricity needs.

Based on relevant available information, there are some suitable notified prices options for EV customers in the existing suite of retail tariffs, but as EV uptake increases, targeted EV pricing will be an important part of broader initiatives to encourage desired customer behaviour.

### Current research and SEQ market insights

Market research suggests customers would need quite strong price signals (and incentives) to change charging behaviour. In particular, the University of Melbourne's study into electric vehicle uptake and charging[58] found that:

- without demand management strategies (such as TOU tariffs, reward systems, or system managed smart charging), EVs are most likely to be charged when arriving at work or upon returning home from work during the hours of 5 pm to 8 pm. Charging during this evening window may place further strain on the network during the peak demand window
- engagement in TOU tariffs by EV users was mixed. In a 2013 EV trial, only 20 per cent of participants charged their vehicle after 11 pm, demonstrating limited responsiveness to off-peak charging windows
- a 2019 study of United States EV owners found that 65 per cent were on TOU tariffs and that 87 per cent of this cohort charged during off-peak periods. Most EV owners that did not opt

[55] Canegrowers, sub. 6, p. 2; Bundaberg Regional Irrigators Council, sub. 1, p. 2; EER, sub. 5, pp. 7.
[56] EER, sub. 5, p. 7.
[57] Cotton Australia, sub. 3, p. 3.
[58] University of Melbourne, *Electric Vehicle Uptake and Charging: A consumer focussed review*, April 2021.

for a TOU tariff indicated that they were comfortable with the extra expenses associated with a flat-rate tariff

- adoption of TOU tariffs has been reported to be higher when there have been marketing campaigns, there is no cost to switch to a TOU tariff, and bill savings were achievable by EV customers.

We also consider that covid-19 and working from home arrangements are likely to have a significant impact on customers charging behaviour. While people work from home more, charging during the day is likely to be more convenient and require less encouragement than would otherwise be the case. However, it is not certain how long such arrangements will continue (or should be relied on to influence customer behaviour).

As part of monitoring SEQ electricity market trends, we found evidence that some SEQ retailers are packaging EV tariff options for customers with price signals to encourage charging in particular time periods. On current SEQ market data[59], there were four retailers with specific EV pricing offers that encourage off-peak customer charging, but not necessarily during the day when renewable generation is high. For instance, of the four retailers with specific EV pricing offers:

- two retail offers encourage charging of vehicles late at night (i.e. between 10 pm and 7 am) by offering the lowest variable charges for this period
- the third retail offer has a broad off-peak period covering 9 pm till 4 pm (19 hours)
- the fourth retail offer has incentives to charge EVs outside the daily peak demand window (i.e. by offering electricity at a cheaper rate when charging EVs from 12 am to 5 am).

### Suitability of existing retail tariffs

There are some existing notified prices containing price signals that may appeal to EV customers:

- The TOU tariff 12B option (and the small business version tariff 22B) is most likely to encourage desired customer charging behaviour. As the Minister noted, it has low daytime charging rates to encourage daytime charging when renewable energy generation is high.
- In comparison, other potentially appealing tariffs (such as tariff 14B and 24B, plus the secondary load control tariffs 31 and 33) are likely to encourage charging outside of peak times, but not necessarily during the day when renewable energy generation is high.

The table below summarises these options, including details of the tariff structure and customer behaviour outcomes likely to result from these price signals in these retail tariffs.

[59] AER, *Find the right energy plan for you*, Energy Made Easy website, Australian Government, accessed 31 December 2021.

| ***Tariff*** | ***Tariff structure*** | ***Customer behaviour*** |
|---|---|---|
| **Tariff 12B**<br>Residential TOU | Usage:<br>• Peak (4 pm to 9 pm)<br>• Day (9 am to 4 pm)<br>• Night (all other times)<br>Daily supply charge | Incentivise shifting EV charging towards periods when network demand is low and renewable energy generation is high, by having the lowest variable charges during daytime periods (time of use tariffs 12B and 22B) |
| **Tariff 22B**<br>Small business TOU inclining band | Usage (same structure as 12B)<br>Daily supply charge: (5 inclining bands) | |
| **Tariff 14B**<br>Residential TOU monthly demand | Usage<br>Demand: Peak only (4 pm to 9 pm)<br>Daily supply charge | Incentivise shifting EV charging away from periods of high network utilisation as demand charging windows are calculated during peak periods |
| **Tariff 24B**<br>Small business TOU monthly demand | Same structure as 14B | |
| **Tariff 31**<br>Small customer secondary load control | Usage—supply available for a minimum of **8 hours per day** (at the discretion of the distributor) | Ramp up or down network demand by allowing the distributor to dictate supply availability |
| **Tariff 33**<br>Small customer secondary load control | Usage—supply available for a minimum of **18 hours per day** (at the discretion of the distributor) | |

At this time, we do not have data to draw conclusions on how successful these existing tariffs have been at influencing customer uptake of EVs, or customer charging patterns and behaviours. However, based on the market insights discussed previously, even with TOU tariff options available, customers are likely to need further encouragement[60] to choose TOU tariffs and charge their vehicles during the day when renewable energy supply is high and network demand is low.

Importantly, any price signals in current retail tariffs, including those described above, are all based on the underpinning network tariffs. This is a function of the N+R cost-build up approach we use to set prices (discussed in section 3.1) and the fact we pass through underlying network prices and tariff structures to set notified prices.

This means that the network imperative of encouraging more customer demand outside of the peak period may, but not necessarily, align with broader imperatives desired when it comes to EV tariffs (such as encouraging daytime charging when renewable energy generation is high). Coincidently, the price signals in the underlying network tariffs that correspond to retail tariff 12B and the small business version, tariff 22B, do encourage customer charging during the day when renewable energy supply is high. In contrast, the other network tariffs (which contain more network-focused price signals) may, but not necessarily, encourage the desired behaviour. Under these tariffs, price signals encourage customers to charge EVs outside of times of high network demand—typically during the night, or at times of lower demand during the day.

As a result, as EV uptake increases, more targeted EV tariffs, containing stronger price signals, will likely be an important part of the overall suite of initiatives needed to encourage desired customer behaviour and charging patterns.

[60] That is, incentives and/or stronger price signals.

### Options for developing targeted EV tariffs

Under our price-setting framework, more targeted EV tariffs need to be considered in the context of network prices (which underpin the retail tariffs we set) and the retail cost component (which is set by us).

In relation to network prices, any new network tariffs aimed at EV customers that the distribution businesses introduce in future could form the basis of new EV-specific retail tariffs. Similarly, if existing network tariffs are modified in future, these could also be used as the basis for setting notified prices.

It is evident from the Minister's cover letter and EEN and Energex's comments that work is being undertaken to develop network tariffs specifically targeted to EVs for the next AER regulatory period (2025–30). It is also worth noting that EQ is currently conducting its SmartCharge Queensland research program[61], which electronically monitors the EV charging events of 200 EVs in Queensland over three years. The outcomes of this program are likely to:

- provide key insights into how EV charging patterns differ and change over time, and what influences any changes
- support the development of evidence-driven strategies to influence future EV pricing, including to facilitate and promote customer charging patterns that optimise electricity usage and reduce demand on the network.

This research, including data gathered on customer preferences, will provide meaningful insights into EV tariffs developed. We intend to monitor progress on this and provide any updates to stakeholders in the final determination.

In terms of the retail component, the Minister raised the prospect of a TOU retail tariff with improved price signals. Specifically, the Minister noted that tariff 12B (as a 'solar-soaker' tariff) has an inexpensive daytime off-peak network component but an energy cost component that is flat across all time periods. Stakeholders also suggested we should introduce a time-varying wholesale energy component for TOU to provide stronger price signals within the existing suite of retail tariff options.

The Minister also indicated that TOU tariffs are critical policy levers that can be used to support the integration of various technologies, including EVs, batteries and energy management systems.

As a result, we have undertaken a preliminary assessment of the feasibility of estimating time-varying wholesale energy costs. Our preliminary analysis found:

- The spot price for electricity varies throughout the day and is typically higher during periods of peak demand. Spot prices are now consistently low during daylight hours due to the influx of utility-scale solar generation and small-scale solar PV systems. However, when estimating wholesale energy costs, our methodology reflects how retailers incur costs in the NEM. Retailers incur wholesale energy costs when purchasing electricity from the NEM to on-sell to their customers (who are either on accumulation or smart meters).
- Currently, most customers in Queensland are on accumulation meters (approximately 80 per cent of small customers).[62] Unlike smart meters, accumulation meters do not record how

[61] Ergon Energy Network and Energex, *Network electrical vehicle tactical plan: Summary*, October 2020, p. 15. Information and EV insights can also be found on Ergon Energy Network's website.

[62] AEMC, *Review of the regulatory framework for metering services*, directions paper, September 2021, p. 44.

much electricity was consumed at a particular point in time (and therefore does not have a time-varying aspect). Rather, accumulation meters simply measure how much electricity has been consumed over an entire billing period.

- When retailers acquire electricity from the NEM, they pay the Australian Energy Market Operator (AEMO) based on spot prices that fluctuate every 5 minutes. However, as noted above, accumulation meters do not record when electricity was consumed. To address this issue, AEMO develops regional net system load profiles (NSLPs) to approximate the timing and amount of electricity consumed by customers on accumulation meters. Given that most customers in Queensland are still on accumulation meters, retailers pay for most of their customers' electricity demand based on the regional NSLPs.
- While the NSLPs have a time-varying aspect, retailers pay for the electricity that their customers use based on a daily average spot price[63] derived from the NSLPs. Hence, a flat-rate wholesale energy cost estimate best reflects how retailers incur the majority of their costs in practice.
- We consider that it is feasible to estimate time-varying wholesale energy costs for customers on smart meters. However, there are issues that need to be resolved, including:
  - retailers' hedging strategy to manage spot price volatility[64]—it is unclear how retailers would hedge in practice when there are different demand profiles for accumulation and smart meters. Due to the low penetration of smart meters, it is likely that retailers would combine the profiles for smart meters and the NSLPs (for a specific customer group) when undertaking hedging activities
  - demand profiles of smart meters are not published by AEMO. Consequently, more work needs to be done to obtain the relevant profiles from AEMO
  - the relatively low penetration of smart meters (i.e. the small customer base) can lead to some volatility from year to year in the shape of this demand profile. This could introduce significant variation year-on-year in wholesale energy costs estimates for customers on smart meters.

We consider that more work needs to be done to determine an appropriate methodology for estimating time-varying wholesale energy costs for customers on smart meters. As such, we do not propose to implement any time-varying energy components as part of this determination. At this stage, we have commenced work in obtaining the relevant demand profiles for smart meters from AEMO and are investigating the robustness of these data sets.

Given this is an emerging issue, we expect to progress and develop our preliminary analysis over time and with the benefit of further information, including from stakeholders. We strongly encourage stakeholders, including customers, retailers and distributors, to provide comments on any matters they consider relevant. This will be taken into account in our analysis in the final determination.

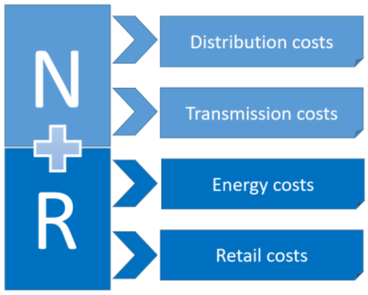
[63] This average price is estimated by taking the average of daily spot prices weighted by the electricity demand recorded under the NSLPs. In other words, spot prices with higher demand contribute more to the average price.

[64] Retailers adopt a range of hedging strategies (such as purchasing financial contracts) to manage and reduce spot price volatility. This is because the NEM is a volatile market where spot prices are determined every 5 minutes and currently can range from –$1,000 to $15,100 per megawatt hour.

# 4 INDIVIDUAL COST COMPONENTS

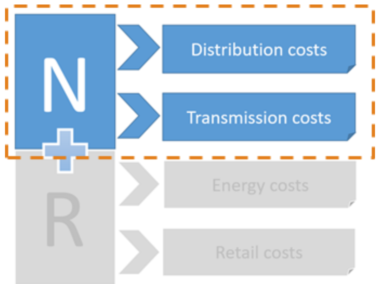
This chapter provides our draft position on matters related to the individual cost components that make up a retail tariff. Many of these matters are identified in the delegation and terms of reference, which we must consider when setting notified prices.

The cost components include:




- the network (N) component—distribution and transmission costs associated with transporting electricity to customers (section 4.1)
- the retail (R) component—the costs of buying and selling electricity to customers (section 4.2)
- other adjustments and price matters—the standing offer adjustment and metering charges (chapter 5).

## 4.1 Network component




Network costs comprise the costs of transporting electricity through transmission and distribution networks, as well as jurisdictional scheme charges[65], all of which are regulated (and approved) by the AER.

Overall, network costs this year are expected to:

- decrease by 5 to 11.3 per cent for the main small customer tariffs
- increase by 6.8 to 12.3 per cent for the main large customer tariffs.[66]

The delegation requires us to consider determining the N component in a manner that is consistent with the overarching framework matters—that is, using the UTP and N+R methodology (discussed in section 3.1). When determining the N component, we are also required to consider:

- for residential and small business customers who are on:
  - flat and secondary load control tariffs—basing the N component on the relevant Energex network prices (being the charges and tariff structures levied by Energex that apply in SEQ)
  - tariffs 12A, 14, 22A and 24— basing the N component on the N component used in the 2021–22 price determination, adjusted using a price indexation methodology (on the basis that these tariffs no longer have an underlying network tariff)
  - tariffs 62A, 65A and 66A (limited access obsolete tariffs)—basing the N component on the relevant network prices for Ergon Distribution's east zone, transmission region one
  - all other retail tariffs—on the price level of the relevant Energex charges but utilising Ergon Distribution tariff structures

[65] In Queensland, these charges generally include the Solar Bonus Scheme (SBS) and AEMC levy costs.
[66] These changes are based on the annual bills for typical customers.

- for large customer retail tariffs—basing the N component on the relevant network prices for Ergon Distribution's east zone, transmission region one.[67]

The delegation is similar to previous years' delegations and the way in which we have set the N component of notified prices in previous price determinations.

### Stakeholder comments

EER supported our approach to setting the N component across the various small and large customer tariffs.[68] EEN and Energex also supported the N+R methodology of passing through the relevant network prices and, for the tariffs without underlying network tariffs that we propose to remove from the tariff schedule, the continued use of a price indexation approach while those tariffs are being phased out.[69]

Customers raised a number of broader issues relating to the N component and setting notified prices. These are set out and addressed in section 5.4.

### Analysis and draft position

When we determined the N component for existing tariffs (for both small and large customers) and new tariffs, we had regard to the relevant factors, stakeholder comments and our own analysis. We have set the N component:

- for retail tariffs with an underlying network tariff, by passing through the relevant network prices approved by the AER. Consistent with the UTP, this means:
  - for small customers on standard retail tariffs, basing costs on the costs of supply in SEQ (Energex distribution area)
  - for large customers, and small customers on the limited access obsolete tariffs, basing the costs of supply on east zone, transmission region one (Ergon Distribution's lowest-cost region that is connected to the NEM)
- for retail tariffs with no underlying network tariff (tariffs 12A, 14, 22A and 24), using a price indexation methodology, specifically an 'X-factor' approach[70], which allows for the pass-through of AER-approved changes in network costs to customers on these retail tariffs.[71]

Setting the N component as described above is consistent with our broader pricing approach (see section 3.1) and the approach we have applied in previous price determinations.

As discussed in section 3.2, we propose to rationalise a number of tariffs. For those tariffs that we propose to make obsolete, we have determined the network cost component as outlined above (reflecting that existing customers may still be on these tariffs until their phase-out date). For tariff 20A, which we propose to extinguish, we have also determined the network cost

[67] Being the Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM.
[68] EER, sub. 5, p. 9.
[69] Ergon Energy Network and Energex, sub. 4, pp. 2–3.
[70] 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 price formula of the form (CPI–X).
[71] Specifically, we propose to use the N component that was set for these tariffs as part of our 2020–21 determination as the starting point, which will then be indexed by using the relevant AER X-factors and the 'CPI minus X' price formula. For further details on how we set the N component for these tariffs, see Appendix C of our 2020–21 price determination.

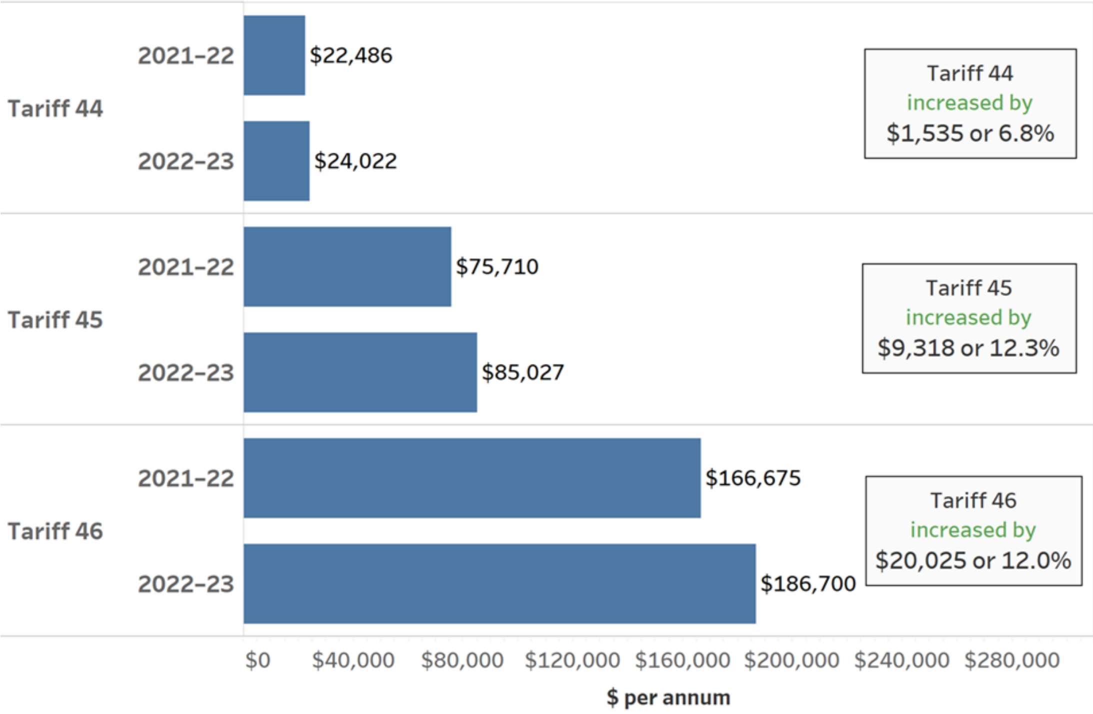
component as outlined above for consultation purposes. If we extinguish this tariff in our final determination, we will not set a price for this tariff.

Overall, this year, the network costs included in the draft notified prices have decreased for small customers and increased for large customers. This can be seen in the charts below.

**Figure 4.1 Draft network costs—typical customers on small customer tariffs (incl. GST)**


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

**Figure 4.2 Draft network costs—typical customers on large customer tariffs (incl. GST)**



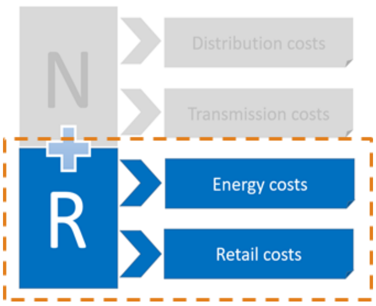

*Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.*

### Timing

Due to our review timeframes, we used draft network prices provided to us by Ergon Distribution and Energex as the relevant network prices. We intend to use the prices approved by the AER in its 2022–23 network determinations in our final determination, pending the availability and timing of this information.

If at the time of our final determination the AER has yet to publish the approved network prices, we propose to use the 2022–23 prices submitted to the AER by Ergon Distribution and Energex. If the AER's approved prices differ from those submitted by Ergon Distribution and Energex, we will consider using a cost pass-through mechanism to adjust for material differences, if we are delegated this task in the future.

## 4.2 Retail cost component




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

We propose to use broadly the same approach to determine energy costs that we adopted last year.

Total energy costs are expected to increase by 16.5 per cent to 20.8 per cent for the main small customer tariffs and by 19.2 per cent for the main large customers tariffs.

For retail costs, we propose to use the existing retail cost allowances for small, large and very large customers, adjusted by inflation.

Overall, total retail costs are expected to increase by 4.2 to 8.8 per cent for residential customers, increase by 5.3 per cent for small business customers, and increase by 9.7 to 13.8 per cent for large customers, depending on the tariff.[72]

### 4.2.1 Energy costs

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

Consistent with previous years, we have engaged ACIL Allen (ACIL) to provide expert advice on energy costs.[73] Our draft position for this review is to estimate energy costs based on ACIL's advice.

#### Stakeholder submissions

Queensland Farmers' Federation and Canegrowers supported our view that wholesale energy costs should reflect how retailers incur costs when purchasing electricity from the NEM.[74]

Canegrowers suggested that we should conduct an ex post analysis of the actual energy costs that EER incurred when setting our estimates for wholesale energy costs as part of future determinations.[75]

EER supported the continued use of the market hedging approach to estimate wholesale energy costs but noted the difficulty in forecasting price outcomes within the NEM due to unforeseeable events. EER considered that its limited ability to recover unforeseeable costs should be taken into account when determining wholesale energy costs. Specifically, EER suggested the need for a trigger to reopen and update the wholesale energy cost estimates when an unexpected event occurs. It also proposed that we update our energy cost modelling to allow for supply-side events, additional volatility and a spread of wholesale prices that aligns with market trends.[76]

EER also highlighted:

- the increasing incidence of negative spot prices within the NEM
- the low level of open interest[77] in cap contracts traded on ASX Energy
- the recovery of NEM fees associated with the distributed energy resources (DER) integration program and 5-minute settlement compliance.[78]

EER provided in-principle support for the use of demand profiles from smart meters to inform our estimation of wholesale energy costs in future determinations, provided there was sufficient penetration of smart meters in Queensland.[79]

#### 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

[72] These changes are based on the annual bills for typical customers.
[73] ACIL Allen, *Estimated Energy Costs*, draft report prepared for the QCA, February 2022.
[74] Canegrowers, sub. 2, p. 2; Queensland Famers' Federation, sub. 7, p. 4.
[75] Canegrowers, sub. 2, p. 3.
[76] EER, sub. 5, p. 13.
[77] Open interest refers to the number of outstanding contracts that have not been closed (or are still active).
[78] EER, sub. 5, pp. 12–14.
[79] EER, sub. 5, p. 13.

their exposure to volatile wholesale electricity prices (spot price risk) when purchasing from the NEM, including pursuing hedging, contractual and operational strategies.

We propose to determine wholesale energy costs based on ACIL's estimates. These estimates were derived using:

- a market hedging approach—such an approach simulates expected spot prices that a retailer faces (having regard to the likely variation in demand profiles and generation and supply costs), and then estimates wholesale energy costs for a retailer that hedges spot price risk (through exchange-traded energy derivatives, i.e. ASX energy futures[80])
- market data up until 21 January 2022—such an approach takes into account the most current information (including developments over the potentially volatile summer period), while still meeting our draft determination timeframe.[81]

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's advice, using a market hedging approach. We consider this approach:

- is likely to produce reliable estimates that best reflect the costs retailers incur when purchasing electricity from the NEM by using the most up-to-date market data and publicly available ASX contract data
- adequately addresses the issues raised in stakeholder submissions.

This approach uses the latest available market data—including information on the uptake of rooftop solar PV, renewable energy resource traces[82], the latest peak demand and supply projections of AEMO, and market participants' formal announcements on generation availability/operation. This means our estimates adequately take into account the likely variation in demand profiles and generation supply/costs (including fuel costs) within the NEM, while still meeting our draft determination timeframe.

Importantly, a market-based approach has the advantage of being more transparent than other methodologies (such as the long-run marginal cost approach), as it makes use of financial derivative data (i.e. ASX contract data) that are in the public domain.[83]

We have noted Canegrowers' suggestion that we use EER's actual energy costs to inform our future energy cost estimates. However, under our regulatory framework, we are required to determine a set of notified prices that is applicable to all retailers. In other words, we determine a benchmark wholesale energy cost that a prudent standalone retailer would incur. For several reasons, the actual costs that a retailer incurs might depart from this benchmark. For example, retailers may choose to hedge their retail load in a different manner by taking on greater risk or they may have some degree of vertical integration. Further, our goal is to forecast energy costs for the forthcoming year; therefore, while looking at historical energy costs may provide some

[80] Generally, the purchase of ASX futures enables retailers to lock in a price, or a maximum price (in the case of caps), at which a given volume of electricity will be transacted at a future date. Therefore, futures contract prices incorporate market participants' risk-weighted expectations of future spot prices.

[81] See Appendix C for a detailed description of ACIL's market hedging approach.

[82] Renewable energy resource traces reflect the availability and quality of renewable resources/generation in different regions, depending on weather and geographical conditions.

[83] The appropriateness of a market hedging approach is discussed further in Appendix C and ACIL's draft report.

indication of the costs the retailer faced in the past, historical costs may have limited relevance in forecasting future costs.

We investigated the points that EER raised on unforeseeable events, including the need:

- for a trigger to reopen and update the wholesale energy cost estimates when an unexpected event occurs
- to update our energy cost modelling to allow for supply side events and additional volatility.

Our current delegation does not allow for the reopening of notified prices beyond the regular determination for each financial year. However, ACIL has updated its analysis using the latest available data, including the latest peak demand and supply projections from AEMO, and market participants' formal announcements on generation availability/operation. ACIL also attempted to capture the additional potential volatility by undertaking a large number of simulations to account for variations in demand, thermal plant availability, renewable energy resource and spot price outcomes. Further, our market hedging approach makes use of ASX contract data, which is forward-looking and reflects market participants' expectations of future spot prices. On this basis, we are satisfied that ACIL's methodology addresses unforeseeable events to the greatest extent practical using the latest available information.

EER raised the topic of the increasing incidence of negative spot prices. Consistent with EER's view, we consider that the continued uptake of rooftop solar PV and the development of utility scale solar PV will likely increase the number of negative spot prices during daylight hours. In its latest analysis for 2022–23, ACIL estimated that the percentage of spot price outcomes less than or equal to zero ranges between 11 and 15 per cent, compared with 6 per cent in 2021. On this basis, we are satisfied that ACIL 's methodology adequately addresses EER's concerns and captures the impacts of negative spot price outcomes during daylight hours.

In relation to EER's comments on cap contracts, we acknowledge that the number of cap contracts still active are lower from 2023 onwards. However, except for 2021–22[84], the cumulative trade volume for cap contracts (to date for 2022–23) is on par with, or tracking close to, the trade volumes in previous years. On this basis, we are satisfied that the markets for cap contracts are reasonably liquid.

At this stage, we consider it reasonable to continue to use the NSLP to determine wholesale energy costs, given the relatively low penetration of smart meters in Queensland.[85] Currently, only around 20 per cent of small customers in Queensland are on smart meters.[86] However, as the proportion of smart meters increases, we may need to consider using alternative load profiles in future determinations. We have also undertaken a preliminary assessment as to how the demand profiles of smart meters could be taken into account when estimating energy costs, including the feasibility of estimating time-varying wholesale energy costs (section 3.2). We have commenced work in obtaining the relevant demand profiles for smart meters from AEMO and investigating the robustness of these data sets.

[84] In 2021–22, trade volume was lower due to the transition to 5-minute settlement.

[85] To allow for settlement within the NEM (with different prices and volumes for settlement every 5 minutes), the AEMO uses the regional NSLPs for customers on accumulation meters. In other words, retailers settled most of their customer demand with AEMO using the regional NSLPs.

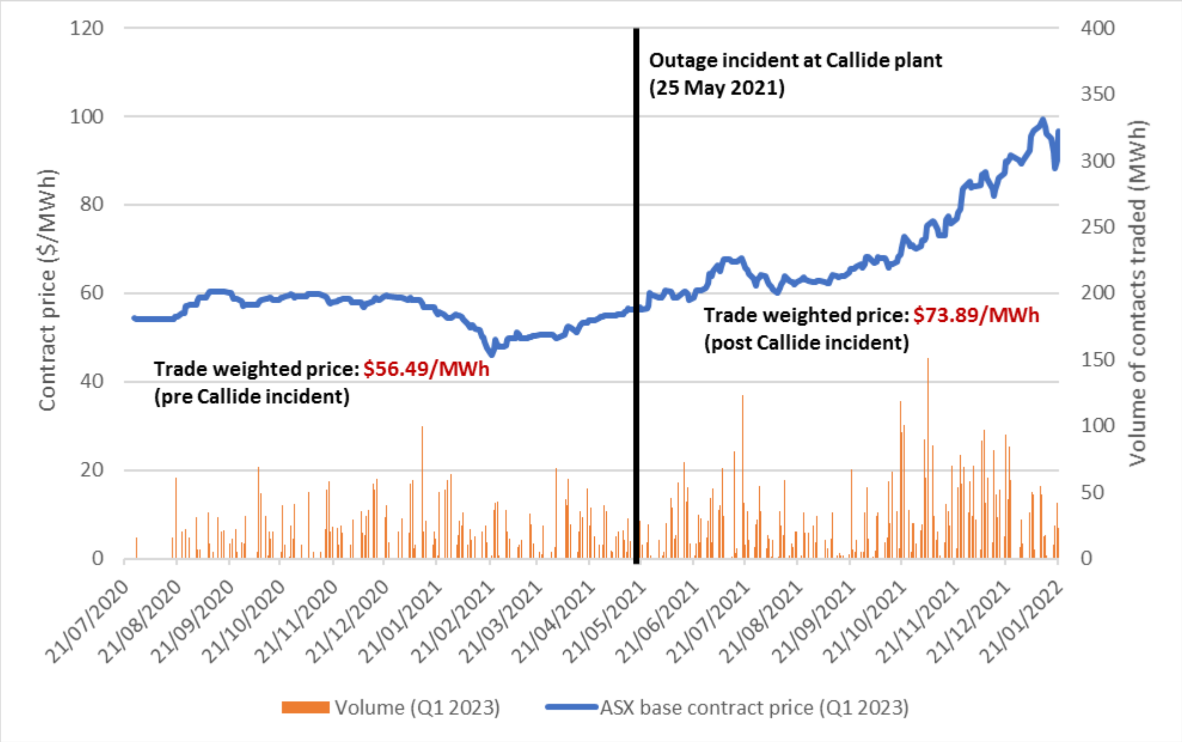
[86] AEMC, *Review of the regulatory framework for metering services*, directions paper, September 2021, p. 44.

Compared to the estimates from last year, our draft estimates of wholesale energy costs have increased for both small and large customer tariff classes[87]:

- for the main small customer tariffs—these costs are 24.3 per cent to 28.9 per cent higher
- for the main large customer tariffs—these costs are 26.7 per cent higher.

These changes reflect a substantial increase in the trade-weighted prices for ASX futures, primarily driven by a slowdown of renewable energy generators coming online (compared to recent years), the continued unavailability of Callide C Power Plant (unit 4), a tighter supply–demand balance in Queensland, uncertainties associated with the effects of 5-minute settlement and higher gas and coal prices (as demonstrated in Figure 4.3 and Table 4.1).

**Figure 4.3 Queensland ASX base contract 2022–23 (summer quarter—Q1 2023)**




*Source: ASX Energy and QCA analysis.*

**Table 4.1 Queensland trade weighted cap contract prices (2021–22 and 2022–23)**

| *Cap contract* | *2021–2022 ($/MWh)* | *2022–2023 ($/MWh)* | *Change (%)* |
|---|---|---|---|
| **Q3** | 2.18 | 5.89 | 170 |
| **Q4** | 5.73 | 9.33 | 63 |
| **Q1** | 13.99 | 25.57 | 83 |
| **Q2** | 3.30 | 6.61 | 100 |

*Source: ACIL Allen and ASX Energy.*

[87] 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 and large customers are based on the Energex and Ergon profiles respectively.

### Other energy costs and losses

Retailers incur other energy costs[88] and losses when purchasing electricity from the NEM, namely:

- Renewable Energy Target (RET) costs—costs associated with the purchase of certificates to meet the targets mandated under the RET[89]
- NEM management fees and ancillary services charges—the costs levied by the AEMO to cover the cost of operating the NEM and services used to manage power system safety, security and reliability
- Reliability and Emergency Reserve Trader (RERT) scheme charges—charges levied by AEMO to cover the costs of maintaining power system reliability and security using reserve contracts. The RERT scheme allows AEMO to contract for emergency reserves, such as generation or demand response outside of the NEM
- prudential capital costs—the costs a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX for futures contracts
- costs associated with energy losses—a retailer needs to purchase more electricity than is demanded by customers to allow for losses that occur when electricity is transported (via transmission and distribution networks).

[88] Retailers may also incur costs related to the Retailer Reliability Obligation (RRO). The RRO is designed to assist with managing the risk of declining reliability of generation supply. When the RRO is triggered for a given quarter and NEM region, retailers are required to secure sufficient qualifying contracts to cover their share of the peak demand. At this stage, for 2022–23, the RRO has not been trigged for Queensland and therefore no RRO costs have been incurred. For a more detailed explanation of our considerations and ACIL's approach, refer to Appendix C and ACIL’s draft report.

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

### Analysis and draft position

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

| | |
|---|---|
| RET costs | •Large-scale Renewable Energy Target (LRET) costs—estimated using forward prices for large-scale generation certificates (LGC) and renewable power percentage (RPP) values derived from mandated LRET targets and estimates of electricity acquisitions<br>•Small-scale Renewable Energy Scheme (SRES) costs—estimated using the clearing house price for small-scale technology certificates (STC) and small-scale technology percentages (STP) that reflect the most recent expected uptake in small-scale renewable energy systems |
| NEM fees and ancillary charges | •NEM management fees—estimated using AEMO's historical fees over the preceding 52 weeks<br>•Ancillary services charges—estimated using the average historical costs 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 |
| RERT scheme charges | •RERT scheme charges—estimated using the historical costs published by AEMO for the preceding 52 weeks |
| Energy losses | •Energy losses—estimated by applying transmission and distribution loss factors published by AEMO, in a manner that aligns with AEMO's settlement process |

We consider that these approaches are appropriate and are likely to produce reliable estimates of other energy costs incurred by retailers. These methodologies are aligned with the way retailers incur these costs in practice, and use the latest market data, where available and appropriate, to enhance the accuracy of the estimates.[90]

In relation to EER's comment on NEM fees associated with the DER integration program and 5-minute settlement compliance, we note that these fees have been incorporated as part of this draft decision. As AEMO no longer publishes its fee forecasts beyond the current budget year, our NEM fee estimates for 2022–23 reflect those published in AEMO's report for 2021–22[91] (which includes 5-minute settlement and DER related costs).

Compared to the estimates from last year:

- LRET costs have increased by approximately 6 per cent ($0.24/MWh)—driven by an increase in the forward price of large-scale generation certificates
- SRES costs have decreased by about 24 per cent ($2.81/MWh)—driven by an expected decrease in the number of small-scale technology certificates retailers are required to purchase
- NEM management fees have increased by around 37 per cent ($0.18/MWh)— reflecting an increase in costs related to operating the NEM, including costs associated with the 5-minute settlement compliance and DER integration program

[90] The appropriateness of these approaches is discussed further in Appendix C and ACIL's draft report.
[91] AEMO, *2021–22 AEMO Budget and Fees*, 2021.

- ancillary services charges have increased by approximately 207 per cent ($0.85/MWh)—driven by higher costs for ancillary services in Queensland. This has occurred on days when outages related to upgrades of the Queensland to New South Wales interconnector (QNI) required significantly increased local supply of ancillary services
- prudential costs have increased by around 26 per cent ($0.44/MWh) for small customer tariffs and by about 27 per cent ($0.37/MWh) for large customer tariffs—reflecting higher contract prices and higher expected price volatility in the NEM
- RERT costs have increased by approximately $0.01/MWh—driven by AEMO activating the RERT to assist with power system management following the major incident at the Callide Power Station on 25 May 2021.

Compared to the estimates from last year, our draft estimate of other energy costs is:

- 5.9 per cent ($1.09/MWh) lower for small customer retail tariffs
- 6.4 per cent ($1.16/MWh) lower for large customer retail tariffs.

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

We note that the energy losses in ACIL's draft report are based on AEMO's 2021–22 published loss factors, as the final loss factors for 2022–23 have not yet been published. ACIL will update the loss factors using AEMO's 2022–23 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 typical small and large customers.

**Figure 4.4 Draft energy costs—typical customers on small customer tariffs (incl. GST)**

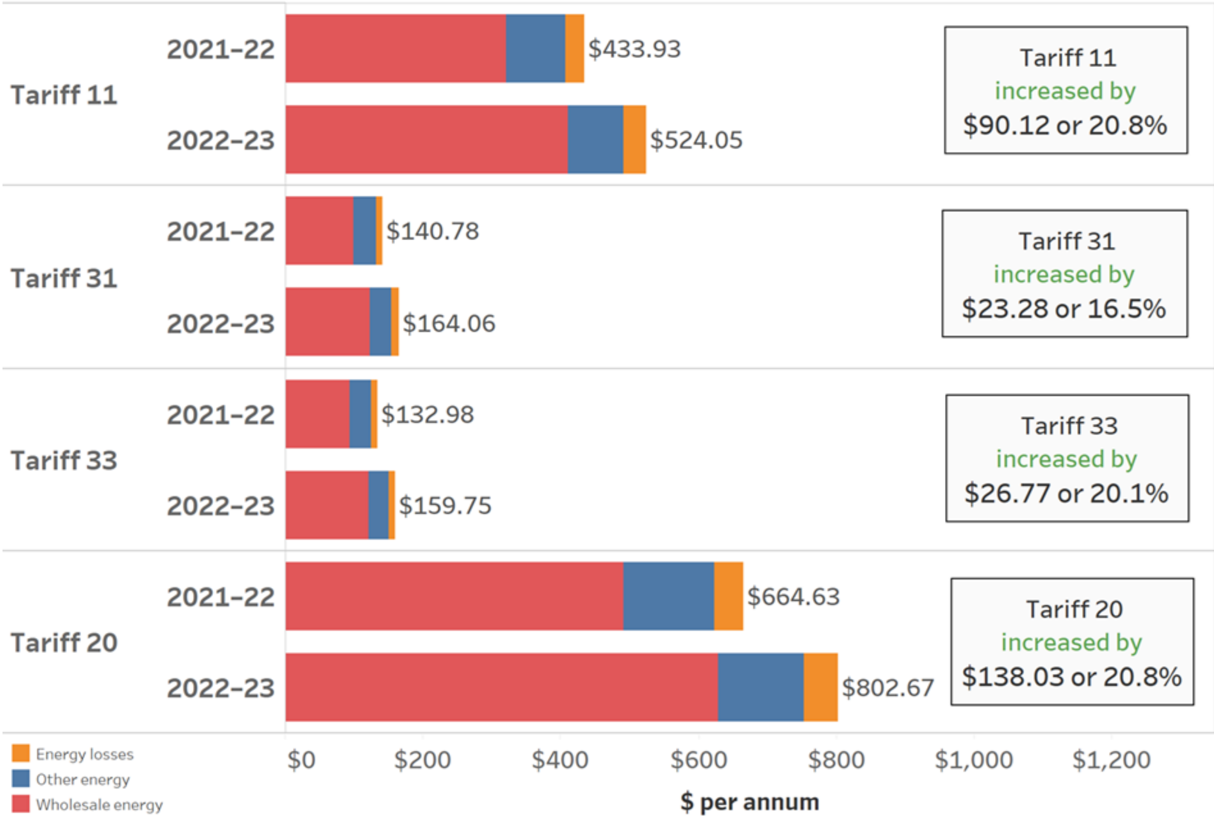
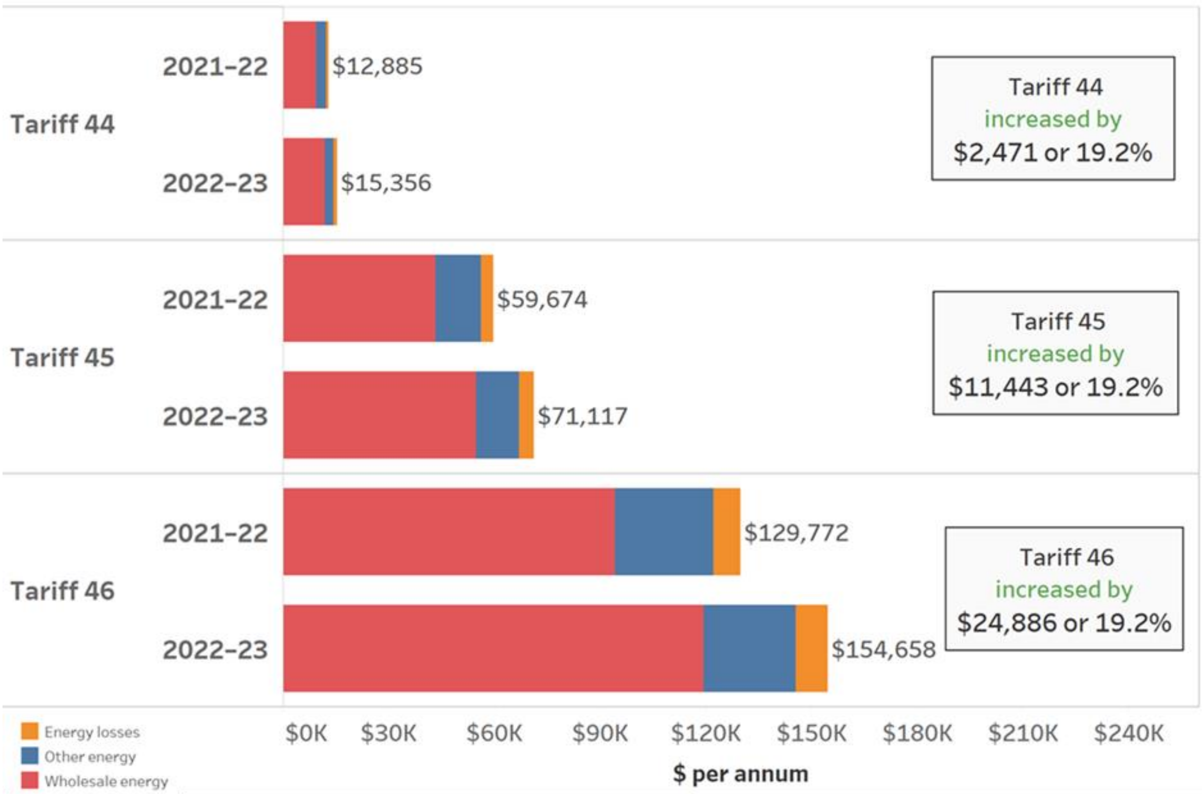



**Figure 4.5 Draft energy costs—typical customers on large customer tariffs (incl. GST)**




*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

Retail costs are the costs of running a retail business. They include:

- retail operating costs, such as administrative costs and costs related to operating call centres, operating billing systems and collecting revenue
- a retail margin, which is the return to investors for retailers' exposure to systematic risks associated with providing retail electricity services.

The terms of the delegation require us to determine the R component, but otherwise do not specify a particular approach or methodology for setting the retail cost allowance.

Last year, we undertook a fulsome review of retail cost allowances for small and large customers. That review used market data and considered potential changes in costs resulting from productivity improvements and covid-19.[92] As a result of that review, we:

- updated the retail cost allowances for residential and small business customers to take account of recent market information, including updating the cost allocator used to set the variable component of the retail costs
- maintained the existing retail cost allowance for large customers[93] (adjusted for inflation), including maintaining the cost allocator used to set the variable component of the retail costs.

Given the recency of the retail cost review, we are considering maintaining our existing retail cost allowances this year, updated to account for inflation.

#### Stakeholders' submissions

EER[94] said the current retail costs were not sufficient to account for:

- ongoing regulatory reforms and increased compliance costs, including multiple AEMC rule changes, upcoming regulatory reforms (including, but not limited to the 'Consumer Data Right') and costs associated with five-minute-settlement
- unique costs associated with operating under the provisions of the retail price gazette, such as being unable to require customers to use e-billing or limit tariff changes (options available to market retailers which can reduce the cost to serve customers)
- the anticipated increase in retail costs due to the prolonged and uncertain nature of the covid-19 pandemic.

As a result, EER said retail cost allowances should be supplemented by a regulatory cost and compliance allowance each year.[95] EER also said we should escalate the retail cost allowance by the Brisbane city CPI estimates (rather than the RBA's CPI estimate we use) and review it every three years.[96]

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[92] For further information on this methodology, see Appendix C; and ACIL Allen, *2020–21 regulated electricity price review: Updating retail costs*, final report prepared for the QCA, May 2021.
[93] There was insufficient evidence to vary the existing retail cost allowances for large customers.
[94] EER, sub. 5, pp. 12–14.
[95] EER, sub. 5, p. 12.
[96] EER, sub. 5, pp. 13–14.

## Analysis and draft position

Having regard to stakeholder comments and our own analysis, our draft position is to maintain the approach used last year and set the retail costs, that is:

- for small customer tariffs, by:
  - adjusting the 2021–22 fixed retail cost allowances by the Reserve Bank of Australia's (RBA's) forecast of the change in the CPI for 2022–23 —to maintain the fixed costs in real terms
  - maintaining the variable retail cost allocator at 7.25 per cent for residential customers and 18.7 per cent for small business customers[97]
- for large customer tariffs, by:
  - adjusting the 2021–22 fixed retail cost allowances by the RBA's forecast change in the CPI and
  - maintaining the variable retail cost allocator at 6.0445 per cent.[98]

We considered whether any further adjustments were required—for example, for the regulatory and compliance costs EER described—but have not made any changes to the retail cost allowance this year. Consistent with our approach last year, our view is that it would only be appropriate to adjust for developments expected to result in material changes in retail costs in the upcoming year, compared to the current year.

The factors EER raised are neither new or unique to EER, nor are they expected to result in a material increase in costs in 2022–23 compared to 2021–22 (including accounting for covid-19).

Market reports suggest the net impact on the electricity market of covid-19 remains uncertain. Decreases in retail costs (partially due to the decrease in debt collection expenses[99] and customer acquisition and retention)[100][101] have been offset by increases in bad debt (some customers transferring away to other retailers with unpaid debts).[102] Taking into account these factors, there is no conclusive evidence to support any adjustment (either increase or reduce) to retail cost allowances, other than to account for inflation.

We will review this position, including in response to submissions on this draft determination as part of finalising our final determination.

We have not changed our approach to escalate the retail cost allowances in the manner EER suggested (i.e. using Brisbane city CPI estimates). The RBA's CPI estimate has been used for some time and is broadly recognised as appropriate for indexing cost inputs.

Further information, including the detailed retail costs for each tariff, are set out in Appendix F.

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[97] This variable retail cost allocator was established as part of last year's retail cost review.

[98] This variable retail cost allocator was established in (and has been used since) 2016–17.

[99] In response to the covid-19 pandemic, the AER required retailers to defer referrals to debt collection agencies for recovery actions or credit default listing until at least 30 June 2021—see AER, *Statement of Expectations of energy businesses: Protecting consumers and the market during COVID-19*, 9 April 2020.

[100] This cost for retailers who are not among the big three retailers decreased by 44% from 2017–18 to 2020–21. For big three retailers, this cost decreased by 27% over the same period. This can be partially attributed to the shift in marketing tactics.

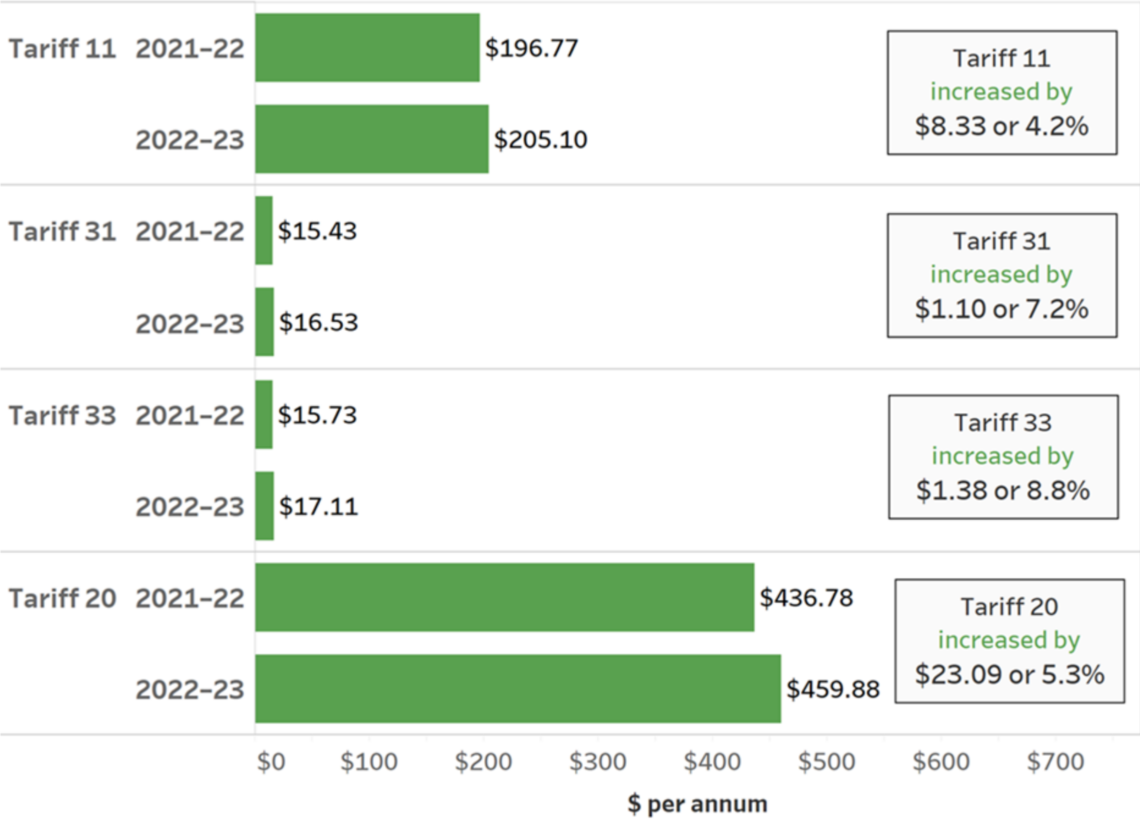
[101] ACCC, *Inquiry into the National Electricity Market—November 2021 report*, November 2021, p. 37.

[102] QCA, *SEQ retail electricity market monitoring 2020–21*, December 2021, p. 152.

## Draft retail cost allowances

The following charts compare the draft retail cost allowances for 2022–23 with the 2021–22 allowances. The comparison is by tariff type for typical small and large customers.[103] Actual costs will vary for individual customers who have different levels of electricity usage.

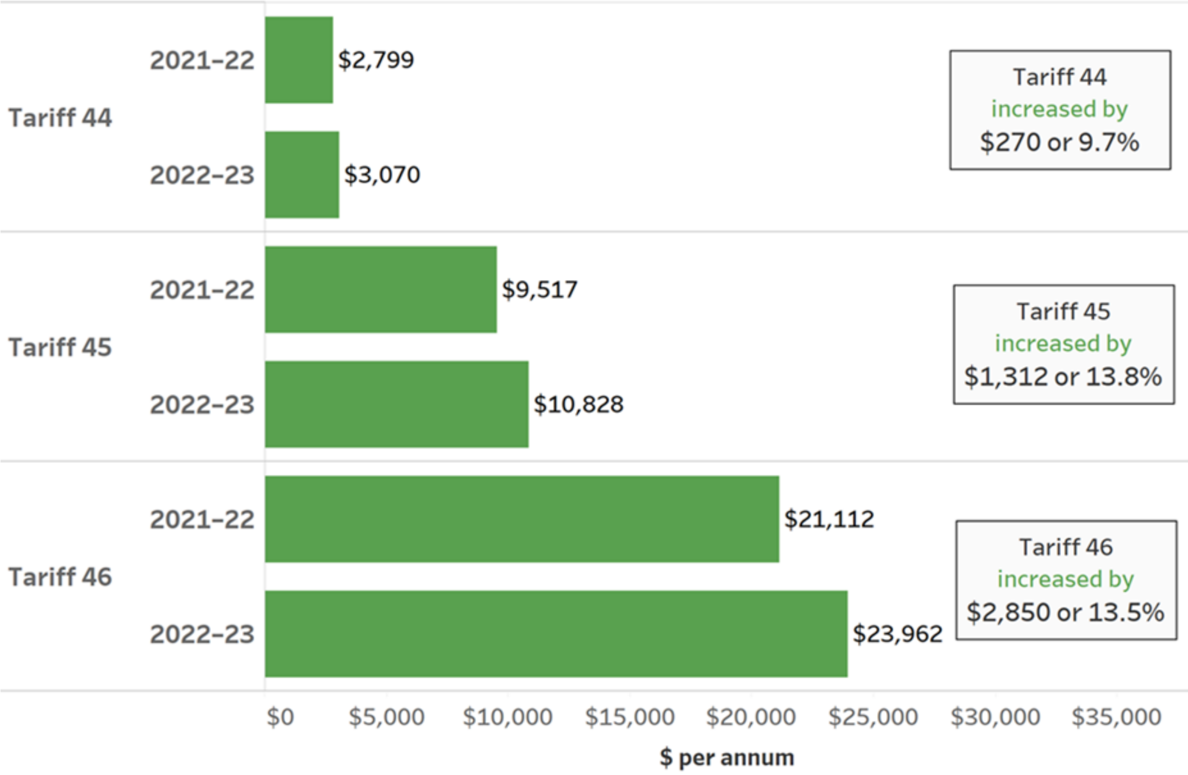
**Figure 4.6 Draft retail costs—typical customers on small customer tariffs (incl. GST)**




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

[103] Typical customer consumption data was provided by Energy Queensland and Ergon Retail (see Appendix E).

**Figure 4.7 Draft retail costs—typical customers on large customer tariffs (incl. GST)**




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

# 5 OTHER COSTS AND PRICING ISSUES

This chapter sets out our draft views on other costs and pricing issues, including any adjustments we need to consider when setting notified prices this year. Many of these matters are identified in the delegation and must be considered when setting notified prices. The matters we discuss are:

- standing offer adjustment for small customers (section 5.1)
- cost pass-through (section 5.2)
- metering costs (section 5.3)
- additional issues raised by stakeholders (section 5.4).

## 5.1 Standing offer adjustment—small customers

### Matters in the delegation

Consistent with previous years, the Minister has asked us to consider the costs and benefits associated with standing offers in SEQ and the effects of the AER's default market offer (DMO) on notified prices.[104]

In our previous determinations, such considerations led us to:

- incorporate a standing offer adjustment (SOA) in notified prices for residential and small business customers. This adjustment was intended to reflect the value of more favourable terms and conditions in standard contracts relative to market contracts.
- In our last determination, we applied SOA of 3.6 per cent of total costs based on an assessment of the potential fees incurred by small customers on market contracts in SEQ. These fees served as an appropriate proxy for the value of the SOA, as they represented the costs that customers would avoid by being on a standard contract relative to a market contract[105]
- compare the notified price bill (including a SOA) to the equivalent DMO reference bill in SEQ and consider discounting the value of the SOA if a notified price bill exceeded the equivalent DMO bill[106]
- in our last determination, no adjustment to discount the SOA was necessary, as none of the notified price bills exceeded the equivalent DMO bills.[107]

Given the delegation matters are similar this year, we plan to adopt the same approach as last year to set an appropriate SOA to incorporate into small customer notified prices.[108]

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[104] Appendix A: Minister's delegation, covering letter.
[105] See QCA, *Regulated retail electricity prices for 2021–22: Regional Queensland*, final determination, June 2021, section 5.1.
[106] Provided that the value is not discounted below zero.
[107] See QCA, *Regulated retail electricity prices for 2021–22: Regional Queensland, Technical appendices*, final determination, June 2021, appendix F.
[108] The AER's publication date may be delayed in order to allow the AER to incorporate recommendations from the review of the DMO Regulations. See AER, *Default market offer prices: Options paper on the methodology to be adopted for the 2022–23 determination (and subsequent years)*, October 2021, p. 15.

## Stakeholders' comments

Stakeholders did not comment on the level of the adjustment but said notified prices should not exceed the DMO in SEQ as this would be incompatible with the Queensland Government's UTP.[109]

## Analysis and draft position

Having regard to relevant matters in the delegation, stakeholder comments and our own analysis, we consider it appropriate to:

- incorporate a SOA of 3.7 per cent of total costs into small customer notified prices
- not discount the value of the SOA based on the DMO comparison because the draft DMO 4 was not published in sufficient time to allow a comparison against draft notified price bills.

### SOA value

We adopted the same approach as last year to determine the value of the SOA, updated to take account of more recent market data.[110]

Using 2020–21 SEQ market data[111], we:

- assessed the range of fees and total charges in retail market contacts
- identified any additional fees in retail market contracts in SEQ compared with standard contracts
- determined the average potential fees incurred by small customers on market contracts in SEQ annually.

Based on our assessment we observed, on average, around $51 of additional fees could be incurred each year by customers on market contracts in SEQ. This equates to, on average, around 3.7 per cent of a small customer's electricity bill annually. Consistent with last year, we consider these fees serve as an appropriate proxy for the value of the SOA, as they represent the costs small customers would avoid by being on standard contract terms and conditions relative to a market contract.

Accordingly, we have incorporated a SOA of 3.7 per cent (of total costs) into small customer notified prices this year. We consider this level of SOA appropriate, as it reflects the potential value small customers in regional Queensland obtain from the more favourable terms and conditions in standard contracts.

We note this is largely consistent with the level of adjustment incorporated into notified prices last year, which was 3.6 per cent of total costs.

### DMO comparison

We have not discounted the value of the SOA included in draft notified prices. The draft SEQ DMO 4 reference bill was published on 18 February 2022, leaving insufficient time for us to undertake a comparison against draft notified price bills. We will review this in the final determination using the AER's draft (or final) DMO 4 reference bill (see Box 1).

[109] Canegrowers, sub. 2, p. 3; QFF, sub. 7, p. 5.
[110] More information on this approach can be found in QCA, *Regulated retail electricity prices for 2021–22: Regional Queensland*, final determination, June 2021, chapter 5.
[111] QCA, *SEQ retail electricity market monitoring 2020–21*, December 2021, chapter 4.

### Box 1 Timing issues affecting the DMO comparison

The Commonwealth Department of Industry, Science, Environment and Resources (DISER) is currently reviewing the DMO Regulations, and a final report is expected to be published by mid-2022.

The AER indicated it intends to publish its DMO 4 final determination in May 2022, but this may be delayed to incorporate recommendations from the DISER review.[112]

As final notified prices must also be published around the same time (by the end of May 2022), we intend to use the most current information available to set our final prices—noting, this may be the draft (rather than the final) approved DMO 4 prices.

We will update stakeholders on this in our final report. We note that any subsequent changes to the final approved DMO 4, if these were to impact the DMO comparison and final notified prices would require a further delegation from the Minister to adjust prices.

## 5.2 Cost pass-through mechanism

Cost pass-through mechanisms are generally used by regulators to mitigate the risk that the forecast costs in regulated prices could be 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.

Consistent with our approach in previous determinations, we propose to provide for the pass-through of small-scale renewable energy scheme (SRES) costs in this determination.

EER queried whether certain NEM fees levied by AEMO[113] should also be recovered via the cost pass-through mechanism[114], but these would be recovered in the energy cost component of the 2022–23 notified prices (discussed in Appendix C).

### SRES cost pass-through

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

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

[112] AER, *Default market offer prices, Options paper on the methodology to be adopted for the 2022–23 determination (and subsequent years)*, October 2021, p. 15.

[113] Specifically, NEM fees related to the 5-minute settlement compliance and distributed energy resource integration program.

[114] EER, sub. 5, p. 12.

### Analysis and draft position

For the draft determination, ACIL has updated the CER's forecast of SRES liabilities for 2022 to reflect the most recent developments in the uptake of small-scale renewable energy systems

The update has resulted in lower than expected SRES liabilities. This means that retailers are likely to be required to purchase fewer certificates to surrender to the CER than initially estimated—leading to an over-recovery of SRES costs for 2021–22 and a decrease in usage charges for all retail tariffs for 2022–23.

For further detail on how the SRES cost pass-through was estimated, see Appendix D.

Our draft position is to incorporate the over-recovery of 2021–22 SRES costs in 2022–23 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 the final 2022 SRES liabilities in March 2022. Therefore, we will 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.

## 5.3 Metering costs

### Small customers

Consistent with last year, the delegation requires us to consider basing charges for advanced digital metering (ADM) for small customers on the cost of standard (type 6) meters in SEQ.

Customers supported this approach.[115] However, EER was concerned over its continued inability to recover the costs of digital meters from small customers and said a separate allowance for ADMs could be applied to regional Queensland.[116]

We acknowledge EER's concerns, including that setting the charges in this manner results in customers paying less for ADM charges than the actual charges associated with supplying the service. However, as this reflects advice from the Minister and the Queensland Government's current policy for setting these charges, we are satisfied it is appropriate to set the charges in this manner. Nonetheless, EER is able to discuss any policy concerns with the Queensland Government directly.

The ADM charges for small customers are set out in Chapter 6.

### Large customers

We did not receive stakeholder comments on large customer metering and consider it is appropriate to maintain our current approach. This approach:

- separates the large customer metering costs for ADMs from retail costs and estimates these metering charges separately

[115] Canegrowers, sub. 2, p. 3; QFF, sub. 7, p. 5.
[116] EER, sub. 5, p. 15.

- estimates metering charges based on confidential data provided by retailers, averaged to produce cost estimates for each large customer type.

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

## 5.4 Additional issues raised by stakeholders

The table below addresses other stakeholder issues raised that are not addressed elsewhere in this report.

**Table 5.1 Additional issues raised in stakeholder submissions**

| ***Stakeholder comment*** | ***Our response*** |
|---|---|
| **Policy matters**<br>Stakeholders raised concerns around the transparency of reporting on government policies and the impact of these on the broader Queensland economy (e.g. payment of the Community Service Obligation (CSO) to Ergon Network instead of Ergon Retail, the solar bonus scheme and reclassification of some Standard Asset Customer Large (SAC large) irrigation customers to small.[117] | Stakeholders commented on a range of matters that go beyond the scope of our review.<br>The framework in which we operate sets boundaries for considering how notified prices should be set (see section 1.2). The Minister's delegation does not unlock investigative and decision-making powers to assess all concerns stakeholders raise (e.g. affordability for particular industry groups in regional Queensland), or implement measures proposed by stakeholders aimed at addressing these concerns (e.g. changing the Queensland Government's customer class threshold or who receives CSO funding). These concerns arise in connection with the development and operation (legislation and policy) of the overarching framework, rather than how a particular task is performed within this framework (our role in setting notified prices). |
| **Access to load control tariffs**<br>Cotton Australia said tariffs T33, 34, 60A and 60B should be provided as dynamic load tariffs, regardless of locational constraints. Cotton Australia did not accept Ergon Network's argument that tariffs 60A and 60B cannot be provided as the area is not serviced by audio frequency load control (AFLC). Either the tariff should be offered without Ergon activating actual load control, or Ergon should invest in alternative internet-based load control systems.118 | The large customer load control tariffs require network signalling equipment to be installed in order to function (this equipment allows the distributor to control the energy supply). While we understand the desire for these tariffs to be available in all areas, we cannot review (or direct) distributors to install or offer tariffs with different signalling technology—network infrastructure and investment are matters for the distributor, and we encourage customers to engage with their retailer and EQ about options for tariffs that would meet their circumstances. |
| **Pricing matters**<br>Stakeholders considered:<br>• irrigators and other small businesses could be encouraged to act as 'solar sponges' if off-peak prices for tariffs 34 and 22A were capped at 14 c/kWh[119] | In accordance with the delegation, we are required to consider setting notified prices using an N+R approach. Under this framework, prices are determined based on AER-approved network costs and observed market data for the retail component. Setting caps on prices for certain tariffs is outside the scope of our powers and a matter of government policy. |

[117] BRIG, sub. 1, pp. 1–2; Canegrowers, sub. 2, pp. 3–4; Cotton Australia, sub. 3, p. 4; PVW, sub. 6, pp. 1–2; QFF, sub. 7, pp. 2, 4.
[118] Cotton Australia, sub. 3, p. 4.
[119] Canegrowers, sub. 2, p. 4; PVW, sub. 6, p. 2; QFF, sub. 7, p. 3.

| ***Stakeholder comment*** | ***Our response*** |
|---|---|
| • an affordable tariff would have a price ceiling of 16 c/kWh, based on network costs and retail costs not exceeding 8c/kWh.[120] | |
| EER proposed the tariff schedule should be amended to remove provisions which allow a customer 12 months to not move onto kVA demand charging (where applicable for a tariff) when:<br>• the customer's meter is upgraded from a type 6 to type 1 meter; or<br>• when moving from an obsolete to a standard retail tariff.<br>EER said these provisions allowed affected customers time to adjust their equipment and/or operations in preparation for kVA charges but have served their purpose now as most large customers will be on kVA demand charging by 30 June 2022. It said it will work with the remaining large businesses who have yet to transition to kVA charging.[121] | Our draft position is to maintain these provisions at this time. Subject to stakeholder views, we consider these provisions still have merit in helping customers transition to kVA charging. We encourage EER to continue to engage with the remaining large customers that have yet to transition to kVA charging. |

[120] BRIG, sub. 1, p. 1; Canegrowers, sub. 2, p. 3; QFF, sub. 7, p. 2.
[121] Ergon Energy Retail, sub. 5, p. 16.

# 6 DRAFT NOTIFIED PRICES

This chapter sets out the draft notified prices for 2022–23. A breakdown of the draft notified prices by cost component is provided in Appendix F. The 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, is provided in Appendix G.

**Table 6.1 Draft notified prices—residential customers (excl. GST), 2022–23**

| ***Retail tariff*** | ***Fixed*** [a] | ***Usage*** | | | ***Demand*** | |
|---|---|---|---|---|---|---|
| | | ***Off-peak/flat*** | ***Shoulder*** | ***Peak*** | ***Off-peak/flat*** | ***Peak*** |
| | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***c/kWh*** | ***$/kW/mth*** | ***$/kW/mth*** |
| Tariff 11—residential (flat-rate) | 90.445 | 20.745 | | | | |
| Tariff 12B—residential time-of-use[b] | 89.719 | 15.585 | 16.555 | 28.211 | | |
| Tariff 14A—residential time-of-use demand[c] | 89.719 | 16.602 | | | 3.789 | |
| Tariff 14B—residential time-of-use demand[c] | 88.060 | 14.968 | | | 7.655 | |
| Tariff 31—night rate (super economy) | | 13.613 | | | | |
| Tariff 33—controlled supply (economy) | | 15.243 | | | | |
| ***Tariffs proposed to be made obsolete from 1 July 2022*** | | | | | | |
| Tariff 12A—residential (time-of-use)[d] | 70.982 | 17.991 | | 53.074 | | |
| Tariff 14—residential seasonal (time-of-use demand)[e] | 43.371 | 14.613 | | | 7.061 | 49.164 |

***a*** *Charged per metering point.*

***b*** *Peak usage—4 pm to 9 pm; shoulder (night) usage—all other times; off-peak (day) usage—9 am to 4 pm.*

***c*** *Demand—4 pm to 9 pm all days.*

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

***e*** *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 6.2 Draft notified prices—small business and unmetered supply customers (excl. GST), 2022–23

| *Retail tariff* | *Fixed*[a] | *Usage* | | *Demand* | |
|---|---|---|---|---|---|
| | | *Off-peak/flat* | *Peak* | *Off-peak/flat* | *Peak* |
| | *c/day* | *c/kWh* | *c/kWh* | *$/kW/mth* | *$/kW/mth* |
| Tariff 20—business (flat-rate) | 122.950 | 23.752 | | | |
| Tariff 24A—business (time-of-use demand)[b] | 122.224 | 20.188 | | 4.004 | |
| Tariff 24B—business (time-of-use demand)[b] | 120.253 | 19.791 | | 9.998 | |
| Tariff 34—business (interruptible supply) | 111.957 | 17.295 | | | |
| Tariff 91—unmetered | | 20.835 | | | |
| *Tariffs proposed to be made obsolete from 1 July 2022* | | | | | |
| Tariff 22A—business (time-of-use)[c] | 111.728 | 22.520 | 56.498 | | |
| Tariff 24—business (time-of-use demand)[d] | 58.418 | 16.987 | | 7.436 | 73.996 |
| Tariff 41—low voltage (demand) | 604.221 | 14.952 | | 18.775 | |

***a*** *Charged per metering point.*

***b*** *Demand—4 pm to 9 pm on weekdays.*

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

***d*** *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 6.3 Draft notified prices—small business customers (excl. GST), 2022–23

| ***Retail tariff*** | ***Fixed band[a]*** | | | | | ***Usage*** | | |
|---|---|---|---|---|---|---|---|---|
| | ***Band 1*** | ***Band 2*** | ***Band 3*** | ***Band 4*** | ***Band 5*** | ***Off-peak/flat*** | ***Shoulder*** | ***Peak*** |
| | ***c/day*** | ***c/day*** | ***c/day*** | ***c/day*** | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***c/kWh*** |
| Tariff 22B—small business time-of-use inclining band [b] | 122.224 | 151.882 | 181.436 | 211.095 | 240.649 | 17.296 | 22.818 | 33.032 |
| ***Tariffs proposed to be extinguished from 1 July 2022*** | | | | | | | | |
| Tariff 20A—small business inclining band | 121.498 | 150.638 | 179.881 | 209.124 | 238.368 | 23.767 | | |

***a*** *Fixed band 1—0 MWh to 20 MWh annual consumption; fixed band 2—20 MWh to 40 MWh annual consumption; fixed band 3—40 MWh to 60 MWh annual consumption; fixed band 4—60 MWh to 80 MWh annual consumption; fixed band 5—80 MWh and above annual consumption.*

***b*** *Peak usage—4 pm to 9 pm weekdays; shoulder (night) usage—all other times; off-peak (day) usage—9 am to 4 pm all days.*

**Table 6.4 Draft notified prices—large business and street lighting customers (excl. GST), 2022–23**

| ***Retail tariff*** | ***Fixed*** | ***Usage*** | | ***Demand*** | | | ***Excess demand*** |
|---|---|---|---|---|---|---|---|
| | | ***Off-peak/flat*** | ***Peak*** | ***Off-peak/flat***[a] | ***Peak*** | ***Flat***[a] | |
| | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***$/kW/mth*** | ***$/kW/mth*** | ***$/kVA/mth*** | ***$/kVA/mth*** |
| Tariff 44—over 100 MWh small (demand) | 4152.510 | 13.341 | | 24.052 | | 21.647 | |
| Tariff 45—over 100 MWh medium (demand) | 13503.091 | 13.341 | | 22.111 | | 19.900 | |
| Tariff 46—over 100 MWh large (demand) | 35207.322 | 13.341 | | 18.120 | | 16.308 | |
| Tariff 50A—large business time-of-use demand[b] | 17433.691 | 13.593 | | | | 14.210 | 2.842 |
| Tariff 60A—large business flat-rate interruptible supply (primary) | 4152.510 | 21.852 | | | | | |
| Tariff 60B—large business flat-rate interruptible supply (secondary) | | 21.852 | | | | | |
| Tariff 71—street lighting | | 26.865 | | | | | |
| ***Tariffs proposed to be made obsolete from 1 July 2022*** | | | | | | | |
| Tariff 50—over 100 MWh seasonal time-of-use (demand)[c] | 3497.391 | 16.414 | 11.686 | 10.840 | 71.116 | | |

***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*** *Demand—4 pm to 9 pm weekdays.*

***c*** *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 6.5 Draft notified prices—very large business customers (excl. GST), 2022–23**

| ***Retail tariff*** | ***Fixed*** | ***Usage*** | ***Connection unit*** | ***Capacity*** | ***Demand*** |
|---|---|---|---|---|---|
| | ***c/day*** | ***c/kWh*** | ***$/day/unit*** | ***$/kVA of AD/mth*** | ***$/kVA/mth*** |
| Tariff 51A—high voltage (CAC 66 kV) | 25041.539 | 11.914 | 6.726 | 3.646 | 3.353 |
| Tariff 51B—high voltage (CAC 33 kV) | 18117.539 | 11.914 | 6.726 | 4.452 | 3.473 |
| Tariff 51C—high voltage (CAC 22/11 kV Bus) | 16918.239 | 11.914 | 6.726 | 5.134 | 4.211 |
| Tariff 51D—high voltage (CAC 22/11 kV Line) | 16232.839 | 11.914 | 6.726 | 9.945 | 8.494 |
| Tariff 53—high voltage (ICC) | 24850.821 | 11.914 | | 3.646 | 3.353 |
| ICC site-specific—high voltage | 2569.121 | 10.180 | | 0.208 | 0.191 |

**Table 6.6 Draft notified prices—very large business customers (excl. GST), 2022–23**

| *Retail tariff* | *Fixed* | *Usage* | | *Connection unit* | *Capacity* | *Demand* |
|---|---|---|---|---|---|---|
| | | *Off-peak* | *Peak* | | | |
| | *c/day* | *c/kWh* | *c/kWh* | *$/day/unit* | *$/kVA of AD/mth* | *$/kVA/mth* |
| Tariff 52A—high voltage (CAC STOUD 33–66 kV) | 13405.839 | 11.708 | 11.087 | 6.726 | 6.306 | 13.046 |
| Tariff 52B—high voltage (CAC STOUD 22/11 kV Bus) | 13405.839 | 11.708 | 11.087 | 6.726 | 4.458 | 46.651 |
| Tariff 52C—high voltage (CAC STOUD 22/11 kV Line) | 13405.839 | 11.708 | 11.087 | 6.726 | 8.155 | 72.017 |

**Table 6.7 Draft notified prices—large business customers (excl. GST), 2022–23**

| *Retail tariff* | *Fixed* | *Usage*[a] | |
|---|---|---|---|
| | | *Below threshold* | *Above threshold* |
| | *c/day* | *c/kWh* | *c/kWh* |
| Tariff 43—Business customer (over 100 MWh) | 4152.510 | 13.341 | 22.243 |

***a*** *Usage (below threshold)—up to 97,000 kWh per year; usage (above threshold)— 97,000kWh per year and above.*

**Table 6.8 Draft limited-access obsolete tariffs—small business customers (excl. GST), 2022–23**

| *Retail tariff* | *Fixed* | *Usage* | | | *Capacity* | |
|---|---|---|---|---|---|---|
| | | *Block 1/ Peak* | *Block 2* | *Off-peak/flat* | *Up to 7.5kW* | *Over 7.5kW* |
| | *c/day* | *c/kWh* | *c/kWh* | *c/kWh* | *$/kW* | *$/kW* |
| Tariff 62A—time-of-use declining block tariff[a] | 106.706 | 58.396 | 48.883 | 18.556 | | |
| Tariff 65A—time-of-use tariff[b] | 106.406 | 45.775 | | 23.757 | | |
| Tariff 66A—dual-rate demand tariff[c] | 224.506 | | | 22.402 | 4.118 | 12.433 |

***a*** *Block 1—7 am to 9 pm on weekdays (first 10,000 kWh per month); block 2—7 am to 9 pm on weekdays (remaining kWh per month); off-peak—all other times.*

***b*** *Peak—a fixed 12-hour period as agreed between the retailer and customer from the range 7 am to 7 pm, 7.30 am to 7.30 pm, or 8 am to 8 pm; off-peak—all other times.*

***c*** *Tariff 66A has a monthly dual-rate capacity charge, instead of an annual dual-rate capacity charge. The capacity charge is determined by whichever is larger—the connected motor capacity used for irrigation pumping or 7.5kW.*

**Table 6.9 Draft metering charges—small customer advanced meters (excl. GST), 2022–23**

| ***Description*** | ***Charge type*** | ***Metering charge (c/day)*** |
|---|---|---|
| Primary tariff | Capital | 7.320 |
| | Non-capital | 3.430 |
| Secondary tariff | Capital | 2.115 |
| | Non-capital | 1.018 |

*Source: Data from Energy Queensland.*

**Table 6.10 Draft metering charges—large and very large business customers advanced meters (excl. GST), 2022–23**

| ***Customer type*** | ***Metering charge (c/day)*** |
|---|---|
| Standard asset customer (annual usage of 750 MWh or less) | 207.603 |
| Standard asset customer (annual usage greater than 750 MWh) | 249.175 |
| Connection asset customer | 429.569 |
| Individually calculated customer | 400.498 |

*Source: Retailer data.*