Queensland Competition Authority

Final determination

Regulated retail electricity prices in regional Queensland 2022–23

May 2022

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1 ABOUT OUR REVIEW

1.1 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).

We commenced our review to set notified prices in December 2021.

1.2 Scope of our review

Since we set prices under a delegation from the Minister, the legislation that applies to the Minister also applies to us when we set notified prices. The framework is contained in the Electricity Act[1] and sets out factors we must have regard to when making a price determination. These factors 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]

We must have regard to factors in the Electricity Act when setting notified prices.

1.2.1 Matters in the delegation

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

- 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.

The Minister sets out particular matters we must consider as part of our review, including how we set notified prices.

A copy of the Minister's 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).

1.3 Review process and consultation

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

We are at the final stage of the review process. The key review dates, including when we have published reports and invited submissions during this review, are provided below.

Figure 1 Stages of the review, including the consultation timetable

1.4 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 all matters required under s. 90(5) of the Electricity Act, including the Queensland Government's UTP.[5,6] These relevant considerations do not have the effect of limiting the human rights identified as potentially relevant, because they provide criteria of general application for the determination of tariffs for a standard customer contract. More specifically, the application of government policy in accordance with the direction (i.e. the UTP) does not limit any potentially relevant human right. To the contrary, it ensures that customers of the same class pay no more for electricity regardless of their geographic location.

[3] Appendix A (Minister's delegation), terms of reference, schedule, cl. 11.
[4] We received 7 submissions in response to our interim consultation paper and 8 submissions in response to our draft determination. These are listed in Appendix B and are available on our website.
[5] As directed by delegation under s. 90AA(3)(c) and (d) of the Electricity Act.
[6] The UTP 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' (see Appendix A (Minister's delegation), terms of reference, schedule, cl. 2(a)).

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

1.5 Report structure

This final determination discusses:

- customer bill impacts (chapter 2)
- the 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)
- notified prices (chapter 6).

Supporting documents

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: Standing offer adjustment approach and default market offer comparison
- Appendix E: Cost pass-through approach
- Appendix F: Data used to estimate customer impacts
- Appendix G: Build-up of notified prices
- Appendix H: Gazette notice.

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]

Information booklet

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

[7] ACIL Allen's report is available on our website.

2 INDICATIVE BILL IMPACTS

Overall, typical customers[8] on all major tariffs can expect an increase in their electricity bill in the coming year based on the notified prices in this report:

- For small customer tariffs, the increase is largely due to an increase in energy costs.
- For large customer tariffs, the increase is largely due to an increase in energy costs and, to a lesser extent, an increase in network costs.

A snapshot of the key elements driving notified price increases is summarised below. Further detail and analysis on individual cost components is provided in chapter 4.

The charts in this chapter show bills for typical customers based on the notified prices for 2022–23, compared to bills based on the current (2021–22) notified prices.[9] Importantly, a 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.[10]

2.1 Why are notified prices increasing this year?

The increase in small customer tariffs is largely due to an increase in estimated energy costs. The increase in large customer tariffs is also mainly due to an increase in estimated energy costs, although network costs have also increased.

Increases in energy costs

The increase in energy costs has been driven by higher wholesale energy costs. The following market developments have contributed to the increase in wholesale energy costs:

- There is a tighter supply-demand balance in Queensland. High demand has combined with reduced generation availability. In particular:
  - significant episodes of high demand have been reported in Queensland, including due to the record heatwaves experienced throughout northern and central parts of Queensland in early March[11]
  - generation availability in Queensland has suffered from increased unplanned outages at both coal-fired and gas-powered power plants.[12]
- Gas and coal prices are higher. Higher international coal and gas prices have been reported, along with prevailing high domestic gas prices to date. In this regard, we note:

[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. Consumption data is set out in Appendix F.

[9] Note, metering charges are excluded from the bill impact analysis for all customer types due to the variety of different metering arrangements that a customer may have.

[10] For customers facing hardship, we provide detail on various resources available to assist in Box 2, section 3.1.3. We encourage customers facing hardship to contact their retailer to discuss available support measures.

[11] Bureau of Meteorology, *Queensland in March 2022*, BoM website, n.d. accessed 9 May 2022.

[12] Callide C (unit 4) has remained out of service since a major incident in the second quarter of 2021, while Kogan Creek was out of service for around 26 days due to an unplanned outage. The Swanbank E gas-fired generator has been out of service for the entire first quarter of 2022. See AEMO, *Quarterly Energy Dynamics Q1 2022*, April 2022, pp. 21, 23.

- the war in Ukraine and sanctions against Russia have added uncertainty to markets already impacted by global supply constraints
- Asian LNG prices have been high and volatile, contributing to the continuation of high LNG exports
- thermal coal export prices reached a record high in early March
- domestic gas prices have remained at or near record levels.

Changes in network prices

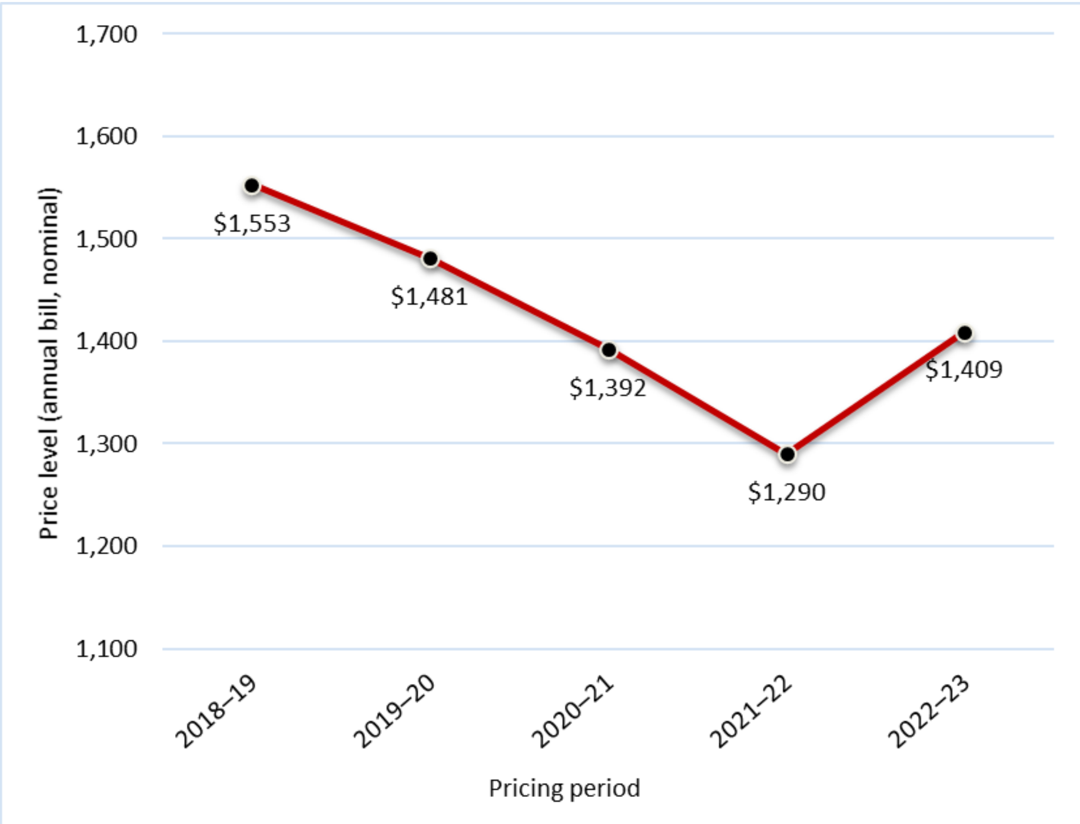
While final network prices have declined by 6.7 to 14 per cent for the main small customer tariffs, they have increased by 6.5 to 12.7 per cent for the main large customer tariffs**,** compared to last year. This outcome reflects the AER-approved network costs (see section 4.1).

2.2 Considering price increases in the broader context

While notified prices are estimated to increase substantially compared to last year, this increase should be viewed within the context of notified prices that have been declining since 2018–19.

For example, despite the increase in the annual bill for typical customers on tariff 11, the 2022–23 bill remains at around the same level as two years ago (2020–21), in nominal terms (Figure 2.1).

Figure 2.1 Changes in notified prices for typical customers on tariff 11 (incl. GST)

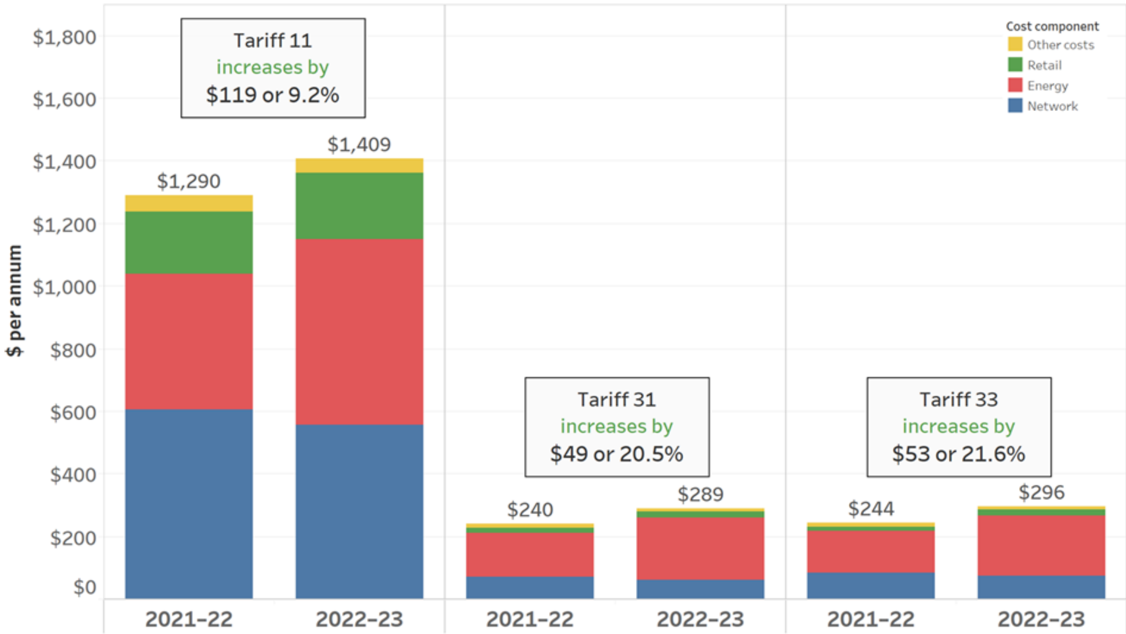


We expect an increase in electricity prices will be felt beyond regional Queensland. The maximum price retailers in south-east Queensland can charge standing offer customers (the default market offer) is set to increase by 11.3 per cent for 2022–23,[13] as determined by the AER. This follows decreases in prior years.[14]

2.3 Residential customers bill impacts

Typical customers on the main residential tariffs (tariffs 11, 31 and 33)[15] are expected to pay around 9.2 to 21.6 per cent more for their electricity in 2022–23 (see figure 2.2).

Figure 2.2 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.

[13] For residential customers without control load, compared to the default market offer price in 2021–22. AER, *Default market offer prices 2022–23*, final determination, May 2022, p. 7.

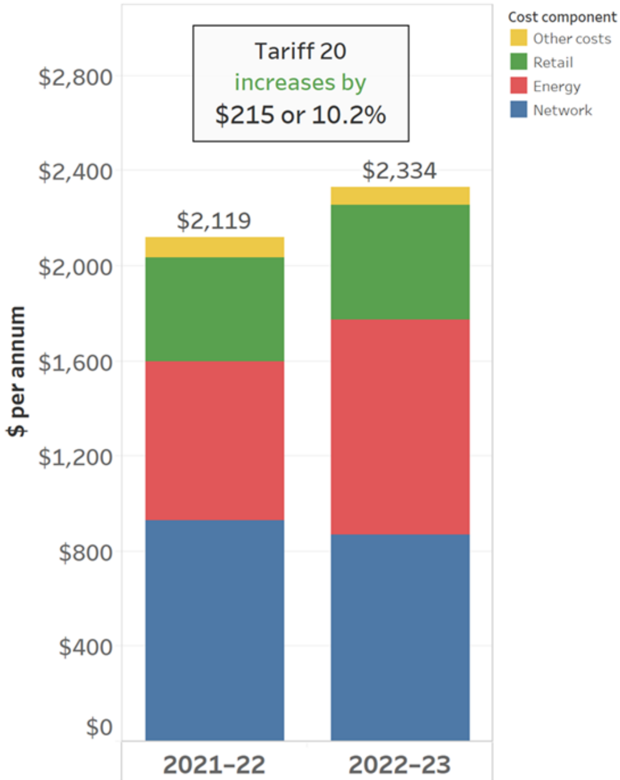
[14] For example, the default market offer (DMO) price for south east Queensland customers decreased by 3.9 per cent between 2019–20 and 2020–21 and by 3.5 per cent between 2020–21 and 2021–22.

[15] 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).

2.4 Small business customers bill impacts

Typical customers on the main small business tariff (tariff 20)[16] are expected to pay around 10.2 per cent more for their electricity in 2022–23 (see figure 2.3).

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



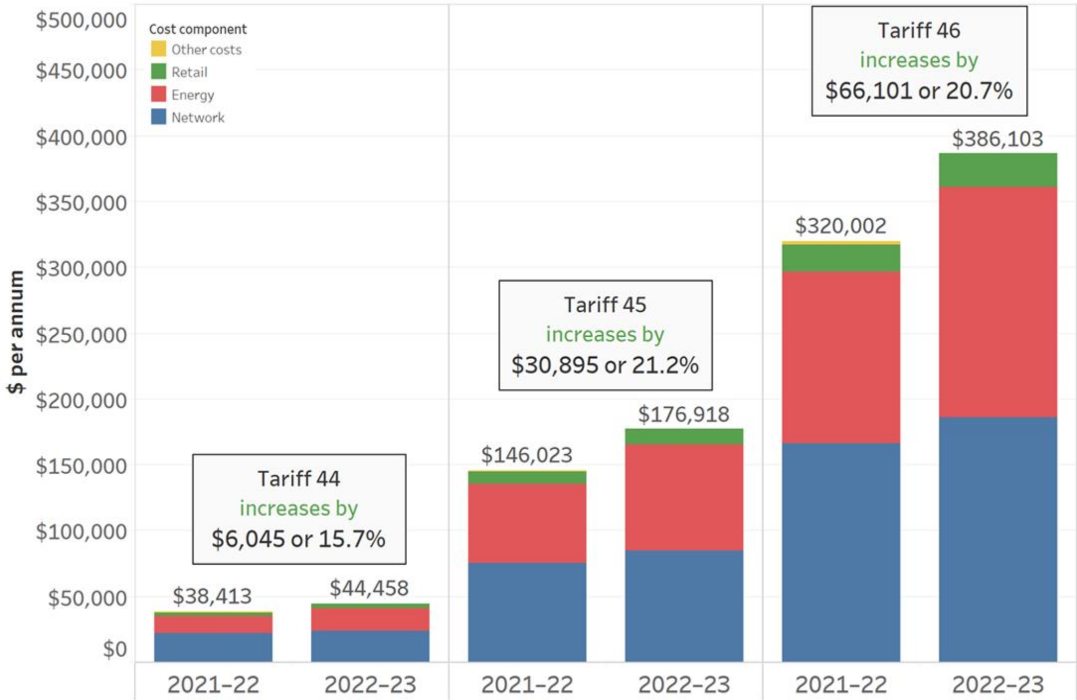
Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

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

2.5 Large business customer bill impacts

Typical customers on tariffs 44, 45 or 46 are expected to pay around 15.7 to 21.2 per cent more for their electricity in 2022–23 (see figure 2.4).

Figure 2.4 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.

3 OVERARCHING FRAMEWORK

This chapter sets out the key issues we have considered in this year's price determination, including overarching matters that determine the cost level and availability of regulated retail electricity prices in regional Queensland (notified prices). Many of these issues are identified in the Minister's delegation (and terms of reference), which we must consider when setting notified prices.

This year, we were also asked to consider a few new matters—to review the tariff schedule and remove any tariffs no longer considered appropriate (see section 3.2.1) and provide commentary on the emerging issue of electric vehicle tariffs (section 3.2.2).

3.1 Our approach to setting notified prices

The Minister's delegation is similar to previous years and requires us to consider the same broad approaches when setting notified prices, including having regard to the Queensland Government's UTP and using the network (N) plus retail (R) cost build-up methodology.

Matters stakeholders raised in the context of our broader approach to setting notified prices, including customer impacts, are discussed in section 3.1.3.

3.1.1 Uniform tariff policy

The Queensland Government's 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.[17]

In previous determinations, we have had regard to the Queensland Government's 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 National Electricity Market (NEM)[18]
- maintaining existing retail tariffs (including those without underlying network tariffs) and introducing 15 new retail tariffs (underpinned by newly introduced network tariffs).

This year, we have used the same approach in terms of cost levels—setting notified prices having regard to the Queensland Government's longstanding UTP. However, we have reviewed the current suite of retail tariffs and removed some tariffs no longer considered appropriate (see section 3.2.1).

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

3.1.2 N+R methodology

The terms of the delegation require us to consider using the N+R cost build-up methodology when setting notified prices. 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 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.[19] 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 matters in the context of the N+R methodology that are outside the scope of our review (discussed in section 5.4).

If the delegation required us to consider changes to the N+R methodology (such as those EER suggested) we could do so based on the guidance provided. For instance, in the past, the delegation 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, and 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. It is also well known and provides ongoing certainty to stakeholders on how prices will be set.

Accordingly, this year we have applied the same approach and used the N+R cost build-up methodology to set notified prices—that is, basing the N component based on the network prices and basing the R component on the retail and energy costs we determined for each tariff. We also applied a standing offer adjustment to small customer notified prices. Further details on how we set the individual cost components are discussed in chapters 4 and 5.

3.1.3 Affordability and price levels

Stakeholders raised concerns about the affordability of notified prices and the impact of price increases for customers. In particular:

- Queensland Electricity Users Network (QEUN) said:
  - the profitability, incomes and viability of industries in regional Queensland had suffered as a result of higher power bills.[20] Electricity customers in regional Queensland are struggling more than customers in SEQ and other states, demonstrated by retail statistics for Ergon Energy Retail's customers, including on the number of credit defaults, placements on hardship programs and disconnections[21]
  - we should quantify the impact of rising power bills on residential and business customers and publish a report detailing the impact of price rises on 'economic and regional development issues, including employment and investment growth'.[22]
- Specific industries raised concerns that rising electricity costs are impacting business viability.[23] The National Irrigators' Council (NIC) said the irrigated agriculture sector are being

[19] EER, sub. 5, p. 5; Ergon Energy Network and Energex, sub. 4, p. 2.
[20] QEUN, sub. 15, p. 3.
[21] QUEN, sub. 15, pp. 3–10.
[22] QEUN, sub. 15, p. 11.
[23] NIBF, sub. 13, p. 1.

held back by unaffordable and uncompetitive energy prices and tariffs, and any rise in costs will put significant pressure on regional businesses, who will eventually need to pass these costs onto consumers.[24]

- Etrog Consulting said there was a strong need to address price and other regulatory matters based on consumer impacts, which had been reinforced by the covid-19 pandemic. In considering customer impacts, Etrog Consulting highlighted the need to consider affordability and household stress.[25]

We are mindful that electricity prices are a primary concern for stakeholders. Customers in the regions, from broader consumer groups to industry-specific consumers, raised concerns around cost pressures, the affordability of electricity prices and the impact price increases may have on households and businesses in regional Queensland.

There are factors we need to consider when setting notified prices. Section 1.2 sets out the key considerations for us when setting notified prices, including the relevant legislative factors set out in the Electricity Act and matters we are required to consider in the Minister's delegation.

Setting prices that are cost reflective is a factor we must consider under the Electricity Act—that is, notified prices should reflect the actual cost of generating, transporting, purchasing and supplying electricity to customers. The Minister's delegation also provides further guidance and directs us to consider using the N+R framework, whereby we pass through network costs (approved by the AER) and estimate the retail costs.

Broadly, cost reflectivity is important to ensure that electricity continues to be provided in a safe and reliable way and to encourage efficient consumption and investment decisions. It is also important for equity reasons, because it affects how resources are distributed in society (for example, if prices are not cost reflective and the difference is paid by taxpayers/the government).

We are not obligated to consider affordability requirements under the Electricity Act, but we are required to consider any matters set out in the delegation, which includes the Queensland Government's UTP. The approach we have taken this year (and in previous price determinations), is to give greater weight to applying the UTP than other factors (i.e. cost reflectivity).

As a result, most customers in regional Queensland pay below the actual costs of supplying them with electricity. This is because the cost level of the notified prices is set at the cost level in SEQ (for small customers) and the lowest-cost Ergon Distribution pricing region (for large customers), with the Queensland Government subsidising the difference (see section 3.1).

The UTP does not shield regional customers from changes in underlying costs, but it does provide lower prices for most customers than would otherwise be the case. We have discussed how the prevailing market conditions have heavily impacted energy costs this year and how the increase in energy costs will impact all customers in Queensland, not only those in regional Queensland.

While we acknowledge the concerns stakeholders have raised, we do not consider it our role to consider and apply measures (beyond those already provided under the UTP) that would further lower prices for customers in regional Queensland. The UTP is a Queensland Government policy—we do not define the UTP, nor can we alter the level at which it is set.

[24] NIC, sub. 12. p. 1.
[25] Etrog Consulting, sub. 16, p. 4.

We also note the UTP is a broad measure implemented by the government that subsidises customers in regional Queensland based on their geographic location. It does not target particular customers or industries, or those who are most in need.

Further actions to address affordability concerns (beyond the application of the UTP) are best achieved through more direct measures, such as concessions and rebates, broader income support arrangements, consumer protection frameworks and customer hardship programs.[26] This ensures that customers who are in need (and are eligible) are able to directly access any additional specific support available when it is needed. Box 2 summarises the key support measures currently available to electricity customers.

It is a matter for governments to determine the ongoing appropriateness of existing support measures to meet social equity and affordability objectives. We encourage any electricity customers that are facing hardship to contact their retailer to discuss support measures that may be available to them.

[26] See Productivity Commission, *Australia's Urban Water Sector*, vol. 1, inquiry report no. 55, August 2011, pp. 217–228.

Box 2 Support for electricity customers in regional Queensland

Customers facing payment difficulties should contact their retailer to find out what support is available.

Hardship policies

Under the NERL, retailers have obligations to help customers that are in financial hardship or face payment difficulties.

Ergon Energy Retail's customer assist program is available to eligible customers who are experiencing financial hardship in payment their electricity bills, including via payment plans.

Government schemes, concessions and other programs and resources

The electricity tariff adjustment scheme helps businesses transition from obsolete to standard tariffs by providing transition rebates on their electricity bills (eligibility requirements apply).

The business energy savers program provides free audits to agricultural customers and large businesses on their energy usage and advice on how to reduce electricity costs by using electricity more efficiently. The Queensland Government worked with the Queensland Farmers' Federation (QFF) to deliver the program (180 agricultural businesses are reported to have used this program to date).

The drought relief from electricity charges scheme provides drought declared farming businesses with relief from supply charges on electricity accounts used to pump water for farm or irrigation purposes.

Further information can be found on the Queensland Government's website.

Resources for stakeholders include:

(a) QFF's website provides a information and resources on electricity prices, understanding your bill, government schemes and concessions available and specific information for different industries, including specific programs available for customers.

(b) Ergon Energy Retail's website provides a range of information to assist customers, including households, businesses and farming customers.

Dispute resolution

Customers can contact the Energy and Water Ombudsman Queensland for information on how to lodge a complaint or resolve a dispute involving their electricity, gas or water supplier.

3.2 New pricing matters

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.[27]

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 application of UTP [uniform tariff policy], this should be informed by the price structures commonly available in the deregulated SEQ electricity market and with a view to future needs for a variety of tariffs to be available as customer preferences, needs and technologies change.[28]

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.[29]

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.[30]
- 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.'[31]

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.[32]
- 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 generation (which is not in the best interests of customers (over the long term) or the energy sector).[33]
- 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.[34]

[27] Appendix A (Minister's delegation), terms of reference, schedule, cl. 2(b).
[28] Appendix A (Minister's delegation), covering letter, p. 2.
[29] Appendix A (Minister's delegation), covering letter, p. 3.
[30] EER, sub. 5, p. 6.
[31] Ergon Energy Network and Energex, sub. 4, p. 1.
[32] EER, sub. 5, pp. 6–7; Ergon Energy Network and Energex, sub. 4, p. 1.
[33] EER, sub. 5, p. 4.
[34] Ergon Energy Network and Energex, sub. 4, p. 1.

- Cotton Australia considered there may be room for rationalising some tariffs but there needs to be a process 'over-and-above' this determination to fully test whether some tariffs meet customer needs.[35]

Analysis and final position

The current suite of tariffs has evolved over time, reflecting both policy and market developments. 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, we do not have access to detailed customer information, unlike retailers, to assess the suitability of tariffs to meet customer needs and circumstances. We also cannot 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 the N+R framework as part of the tariff rationalisation review. We have applied a 'flexible N+R' approach in recent price determinations in accordance with the direction of the Minister, using an indexation approach to determine tariff prices that do not have an underlying network tariff. However, this approach may not be feasible in the longer term and we consider retail tariffs without an underlying network tariff should be removed from the tariff schedule
- 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 tariff rationalisation review.

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 time-of-use (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)[36] assigned to the tariff)[37]—while this consideration is informative, it has not been determinative in our decision to rationalise certain tariffs. It is balanced against other considerations, including the N+R framework

[35] Cotton Australia, sub. 3, p. 2.
[36] 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 market is given its own NMI.
[37] This is based on data provided to us by Ergon Energy Retail as at April 2022.

- customer impact—a transition period should be provided to allow customers who are impacted to assess their options and decide on a suitable replacement tariff.

Having regard to the relevant factors and stakeholder comments, we have decided to rationalise the existing suite of retail tariffs by:

- making six tariffs obsolete from 1 July 2022[38]
- extinguishing[39] a tariff from 1 July 2022.

Importantly, making a tariff obsolete provides a transition period for existing customers to assess their options before they lose access to the tariff.

While most of the tariffs being phased out are small customer tariffs, we consider the remaining tariffs provide an appropriate level of optionality, because each customer class will continue to have access to flat rate, TOU, demand and controlled load tariff types.

Table 3.1 provides an overview of the current tariffs in the tariff schedule, highlighting those we have decided to make obsolete or extinguish. Further detail on our decisions on particular tariffs is provided below.

[38] When a tariff is made obsolete, it means the tariff can no longer be accessed by new customers. Customers who are on the tariff at the time when 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.

[39] 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 decision on tariff rationalisation

Residential tariff	***Decision***	***Large customer tariff***	***Decision***
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	***Decision***	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	***Decision***	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***	***Decision***
Tariff 41 (monthly demand)	Make obsolete	Tariff 71 (flat rate for street lighting)	Retain
		Tariff 91 (business flat rate)	Retain

**Obsolete tariffs (excl. tariff 50) will be phased out on 30 June 2023. The tariff 50 phase-out date is to be aligned with the network tariff phase-out date (once known) and will be set in a future determination.*

CAC: connection asset customers; ICC: individually calculated customers

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

Tariffs 12A and 22A are seasonal TOU tariffs,[40] while tariffs 14 and 24 are seasonal TOU demand tariffs.[41] These four 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.[42]

We have decided to make these tariffs obsolete and to set a scheduled phase-out date of 30 June 2023 (a period of 12 months). This is 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 and we consider it should be similarly phased out at the retail level because:
  - this will reduce complexity—having multiple TOU and demand tariffs for a customer class, with different peak windows, makes it more difficult for a customer to assess which tariff best suits their circumstances. This can deter a customer from moving onto these tariff types
  - this reflects more up to date tariff design—consumption patterns have changed since these tariff structures were first introduced. The peak windows of the more recently introduced TOU tariffs reflect the latest network tariff strategy
- these tariffs have a relatively low uptake—these tariffs have fewer than 200 NMIs assigned to them, apart from tariff 24, which has fewer than 750 NMIs assigned to it.

EER, and EEN and Energex proposed a 12-month phase-out period for each of these tariffs.[43] We consider this timeframe is reasonable, because, as EER suggested, it provides sufficient time for retailers to work with impacted customers to explore suitable alternative tariffs.[44]

For the two residential tariffs (tariffs 12A and 14), Etrog Consulting said retailers should be obligated to inform affected customers that their tariff will be obsolete, advise what tariff options are available and report periodically to us on their progress on this.[45]

Broadly, we expect retailers to engage with any affected customers (residential or otherwise) that will need to transition to an alternative tariff. This situation is not new to EER (retail tariffs have been made obsolete in the past) and it has said it will work with impacted customers. As such, we

[40] These tariffs have a peak usage charge for consumption during certain times of the day in summer months, with an off-peak usage charge for consumption at other times. Tariff 12A is a residential tariff, while tariff 22A is the small business tariff variant.

[41] These tariffs have a TOU demand charge that is calculated based on consumption during certain times of the day. A peak demand charge applies for consumption within this period in summer months, while an off-peak demand charge applies for such consumption in non-summer months. Tariff 14 is a residential tariff, while tariff 24 is the small business tariff variant.

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

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

[44] EER, sub. 10, p. 4.

[45] Etrog Consulting, sub. 16, p. 7.

do not consider it necessary to include new customer engagement and reporting obligations for tariffs 12A and 14 (or the other tariffs that we are making obsolete).

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

Tariffs 14A and 14B are TOU demand tariffs for residential customers.[46] 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.[47] Tariffs 24A and 24B are also TOU demand tariffs but apply to small business customers.[48] Similar to the residential tariffs, tariff 24A is the transitional tariff variant.

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.'[49]

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

- EER said the transitional tariff variants (tariffs 14A and 24A) should be removed, because customer uptake is low, and these customers should be transitioned to the demand tariff (tariffs 14B or 24B), the preferred demand structure and pricing of the Queensland distributors.[50]
- EEN said it does not support removal of any of these retail tariffs, indicating the underlying network tariffs play a critical role in its network tariff strategy, based on the following:
  - There are approximately 161,284 customers in regional Queensland on the transitional network tariff,[51] which EEN 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, EEN expected this number to grow over time. It also argued that retaining the associated retail tariff provides customers with a choice of cost-reflective tariff structures and supports its future strategy.[52]
- Etrog Consulting supported retaining both tariff variants for residential customers.[53]

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:

- Having both tariff variants is consistent 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 EEN's tariff strategy, which has been approved by the Australian

[46] These tariffs have a demand charge that is payable for consumption during a peak window (4 pm to 9 pm).
[47] The difference between these tariffs is that tariff 14A has a lower demand charge but higher usage charge compared to tariff 14B.
[48] These tariffs have a demand charge payable for consumption during a peak window on weekdays (4 pm to 9 pm).
[49] Energex, *Energex TSS Explanatory Notes 2020–2025*, December 2019, p. 32.
[50] EER, sub. 5, pp. 6–7.
[51] 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.
[52] Ergon Energy Network and Energex, sub. 4, pp. 1–2.
[53] Etrog Consulting, sub. 16, p. 7.

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 these tariffs, as they have 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).[54]
- 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 will deny customers the opportunity to move onto a standard demand tariff, including customers currently on one of the other demand tariffs being 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 phasing 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, we have decided to retain both tariff variants in each customer class (i.e. to retain tariffs 14A, 14B, 24A and 24B).

Tariff 20A

Tariff 20A is an inclining band tariff for small business customers.[55] 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).[56] Similarly, Cotton Australia questioned the value provided by tariff 20A compared to tariff 20.[57] 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,[58] although it is unclear whether they consider the underlying network tariff for tariff 20A plays such a role.

We have decided to remove tariff 20A from the tariff schedule, effective from 1 July 2022. While this tariff does have an underlying network tariff, this retail tariff is not used by customers. Also, it is not clear in which circumstances 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.

Unlike for the other tariffs to be rationalised, we decided not to provide a transitional period for tariff 20A. This is because there are no customers on this tariff, based on the latest information

[54] Energex, *Energex Tariff Structure Statement 2020–2025*, June 2020 (erratum August 2020), pp. 18, 20, 21.
[55] This tariff has a flat-rate usage charge and a daily supply charge that has five inclining bands based on annual consumption.
[56] EER, sub. 5, p. 7, sub. 10, p. 4.
[57] Cotton Australia, sub. 3, p. 2.
[58] Ergon Energy Network and Energex, sub. 4, p. 1.

available to us. Also, if customers do opt in to this tariff prior to 1 July 2022, they could be reassigned by retailers to tariff 20, which should not have an adverse impact on them.

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, this network tariff is no longer available to small business customers. In our 2020–21 price determination, we decided to maintain these arrangements for tariff 41 and consider this matter in a future price determination.[59]

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 has a preferable peak period of 4 pm to 9 pm.[60]

We have decided to make this tariff obsolete and set a scheduled phase-out date of 30 June 2023 (a period of 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 that there is a need to maintain this flat demand charge option
- this tariff has a relatively low uptake—fewer than 200 NMIs are assigned to this tariff.

Tariff 50

Tariff 50 is a seasonal TOU monthly demand tariff for large customers.[61] 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.[62] 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.[63] However, customers did not raise this as an issue.

To provide consistency with the network tariff arrangements, we have decided to make tariff 50 obsolete, so that no new customers can access the tariff. Customers have access to similar types

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

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 is 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 if it will be maintained beyond this. This is similar to the approach we took for the limited-access obsolete retail tariffs (tariffs 62A, 65A and 66A), where the expiry date for the underlying network tariffs is uncertain.

We can consider a phase-out date for tariff 50 in a future price 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: electricity pricing for electric vehicles

In the covering letter to the delegation, 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 its 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.[64]

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'.[65]

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 on the need for new EV tariffs with different structures to those currently available and on incentives for EV 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 (more information on this is provided under 'cost considerations' further below, including on the structure of the energy cost component and how retailers incur wholesale energy costs in the market).

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:

- EEN and Energex said:

[64] Appendix A (Minister's delegation), covering letter.
[65] Appendix A (Minister's delegation), covering letter.

  - the existing network tariffs are not sufficiently cost-reflective to incentivise customers to charge their EV at optimal times (so customers pay less to charge EVs during off-peak times and more during the peak period). However, the load control tariffs (tariffs 31 and 33) are a convenient option for customers not wanting to actively manage their network usage that can already be used and do incentivises off-peak consumption
  - 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. [66]
- Canegrowers, Bundaberg Regional Irrigation Group (BRIG) and EER were in favour of retail tariffs sending stronger price signals throughout the day, including by having a lower off-peak usage charge than that included in the existing TOU retail tariffs, to encourage greater consumption during the middle of the day.[67] Additionally, QFF said we should develop a similar 'solar soaker' retail tariff for small business customers based on tariff 22B to provide irrigators and small business customers with optionality.[68]
- EER said we could introduce a time-varying wholesale energy component for TOU tariffs to reflect low wholesale energy costs during the day, but EER did not suggest what this would look like, nor did it provide a detailed proposal. It also said that setting the optimal EV tariff structure is an extensive piece of work outside our annual price setting process, but it supported us continuing to explore approaches to setting time-varying wholesale energy costs. [69]
- Cotton Australia and QFF 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.[70] QFF said users should be consulted on the impacts EVs could potentially have on the NEM, with new tariffs developed in a sustainable way that limits impacts to the system.[71]
- Etrog Consulting said we should expedite assessing EV tariffs and obtaining relevant data, given the speed at which this issue could emerge in light of national and state government policies. Etrog Consulting also said a coordinated approach to this issue is necessary so that network and retail tariffs are complementary, rather than potentially conflicting.[72]

Analysis

EV electricity pricing is undoubtedly important 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 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.

[66] EEQ, sub. 4, p. 3.
[67] Canegrowers, sub. 6, p. 2, sub. 8, p. 5; BRIG, sub. 1, p. 2; EER, sub. 5, pp. 7.
[68] BRIG, sub. 1, p. 2; QFF, sub. 11, p. 3.
[69] EER, sub. 5, p.4, 7.
[70] Cotton Australia, sub. 3, p. 3; QFF, sub. 11, p. 2.
[71] QFF, sub. 11, p. 2.
[72] Etrog, sub. 16, pp. 8–9.

Current research and SEQ market insights

Market research suggests customers would need quite strong price signals (and incentives) to change charging behaviour. A study by the University of Melbourne into electric vehicle uptake and charging[73] 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
- according to a 2019 study of United States EV owners, 65 per cent were on TOU tariffs and 87 per cent of this cohort charged during off-peak periods. Most EV owners that did not opt 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 consider that covid-19 and working from home arrangements may impact on customers' charging behaviour. When people work from home, 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. Based on current SEQ market data[74], there were three 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 three retailers with specific EV pricing offers:

- one retailer encouraged charging of vehicles late at night (between 10 pm and 7 am) by offering the lowest variable charges for this period
- another retailer had incentives to charge EVs outside the daily peak demand window (by offering electricity at a cheaper rate when charging EVs from 12 am to 5 am)
- the third retailer offered a period of free electricity use between 12 pm and 2 pm, but only on weekends.

Suitability of existing retail tariffs

Some existing notified prices contain price signals that may appeal to EV customers:

- The option of tariff 12B, which is a TOU tariff, and the small business version, tariff 22B, is most likely to encourage customers to charge during the day. As the Minister noted, it has

[73] University of Melbourne, *Electric Vehicle Uptake and Charging: A consumer focussed review*, April 2021.
[74] AER, *Find the right energy plan for you*, Energy Made Easy website, Australian Government, n.d., accessed 30 April 2022.

low daytime charging rates to encourage daytime charging when renewable energy generation is high.

- Other potentially appealing tariffs (such as tariffs 14B and 24B, plus tariffs 31 and 33, which are two secondary load control tariffs) are likely to encourage charging outside of peak times, but not necessarily during the day when renewable energy generation is high.

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

Table 3.2 Existing retail tariff options for EV customers

Tariff	***Tariff structure***	***Influence on customer behaviour***
Tariff 12B Residential TOU	Usage charge—peak (4 pm to 9 pm); day (9 am to 4 pm) and night (all other times) 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
Tariff 22B Small business TOU inclining band	Usage charge (same structure as 12B) Daily supply charge—(5 inclining bands)	
Tariff 14B Residential TOU monthly demand	Usage charge Demand charge—peak only (4 pm to 9 pm) 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 Small business TOU monthly demand	Same structure as 14B	
Tariff 31 Small customer secondary load control	Usage charge—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 Small customer secondary load control	Usage charge—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 EV customer charging patterns and behaviours. However, based on the market insights discussed previously, even when TOU tariff options are available, customers are likely to need further encouragement[75] 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 based on the underpinning network tariffs. This is a function of the N+R cost build-up approach we use

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

to set prices (discussed in section 3.1) and the fact that 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, which contain stronger price signals, will likely be an important part of the overall suite of initiatives needed to encourage EV customers to charge EVs during the day.

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 covering 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[76], 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 network tariffs developed in future. We intend to monitor progress on this and encourage stakeholders to do the same, particularly to obtain further information on some of the issues stakeholders raised associated with the broader development of EV network tariffs (e.g. impacts of EVs on the NEM and how these have been considered when developing any new EV tariffs).

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

[76] 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.

wholesale energy component for TOU tariffs 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.

Two key aspects relevant when considering options to best address this issue are:

- cost considerations—that is, whether the methodology, and our wholesale cost estimates, appropriately reflect the underlying costs to retailers of purchasing energy on the NEM
- pricing considerations—that is, assessing the impact of the prices on customer behaviour. In this case, this includes deciding to set prices in a way that does not reflect the underlying costs, for the purpose of influencing customer behaviour.

Cost considerations

We are satisfied that the existing wholesale energy cost estimates are appropriate and reflect the actual underlying cost a retailer is likely to incur when purchasing energy from the NEM to on-sell to customers.

By virtue of the market environment and information available, a flat-rate energy cost component best reflects how retailers are likely to incur their costs in practice. Relevantly:

- While the spot price for electricity varies throughout the day (and is typically higher during periods of peak demand and low during daylight hours), it does not reflect how retailers incur wholesale energy costs when purchasing electricity from the NEM.
- Currently, most customers in Queensland are on accumulation meters.[77] Unlike smart meters, accumulation meters do not record how much electricity was consumed at a particular point in time (and therefore do not have a time-varying aspect). Rather, accumulation meters simply measure the amount of electricity 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. Given most customers are on accumulation meters, AEMO develops regional net system load profiles (NSLPs) to approximate the timing and amount of electricity consumed by these customers. 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[78] derived from the NSLPs. Hence, a flat-rate wholesale energy cost estimate best reflects how retailers incur the majority of their costs in practice.

While we recognise the concerns raised—that is, that a flat rate does not provide the desired price signals to customers, which may be the case—it is important to establish that a flat rate is appropriate from a cost perspective and consistent with the framework in which we set notified prices (section 3.2 discusses the N+R cost build-up approach we use to set prices).

[77] According to the AEMC, around 80 per cent of small customers are on accumulation meters: AEMC, *Review of the regulatory framework for metering services,* directions paper, September 2021, p. 44.

[78] 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.

This is not to say the current approach to estimating wholesale energy costs will remain appropriate over time. As EV uptake increases (and the penetration of smart meters increases), so too will the consumption requirements of customers, and it may be the case retailers do need to treat EV customers differently. For instance, retailers may need to reassess the risks involved, the demand requirements and whether their hedging strategy needs to change when purchasing electricity from the NEM. These factors could impact the costs retailers incur in respect of these customers.

As such, it would be prudent to assess whether our estimation approach remains appropriate and continues to reflect the costs retailers incur in future.

It may be possible to use information of customers on smart meters to inform this assessment in future (which would provide information on the times and amount of energy consumed). While these demand profiles are not currently published by AEMO, we have commenced work in obtaining the relevant demand profiles for smart meters from AEMO and are investigating the robustness of these datasets. However, there are issues that would need to be resolved, including whether it is possible for EV customers to be identified separately, or whether it may be appropriate to review these customers in the context of customers more broadly on TOU tariffs—in which case it may be appropriate to assess whether smart meter data should be used in calculating the wholesale energy costs of TOU tariffs more broadly.

Considering and addressing these issues would require a comprehensive assessment, including allowing sufficient time to investigate issues and take into account stakeholder views and input. Subject to the availability of information, such an assessment could occur in future.

Price considerations

Any options for setting time-varying energy costs (which depart from a flat rate) would not reflect how retailers incur costs in practice (discussed above) and would be a departure from the N+R approach we use. This does not mean a solution cannot be considered and applied—in the past, we have deviated from the N+R framework for policy reasons (and based on guidance from the Minister).

We have considered feasible options that could meet the Minister's intention and create sharper price signals to incentivise customers to shift their consumption from periods of high to low electricity demand. This would be akin to how retailers in deregulated market may act, by adopting pricing strategies to encourage customers to change their consumption pattern, to attract specific customer segments, or to respond to the behaviour of their competitors.

One option would be to:

- use the existing wholesale cost estimates as a base
- allocate this cost to different time periods based on a set of weightings—which would result in lower rates during off-peak periods and higher rates during peak periods (rather than a flat rate) to encourage customers to shift their consumption.
- For instance, this approach could involve deriving a set of weightings that aligns with the distribution of spot price variations throughout the day (which are typically lower during daytime hours). This would create an energy cost component that maintains the same level of costs overall but changes the way costs are recovered through the day (with a view to encourage consumption in a specific way).

This approach is likely to provide stronger price signals within existing TOU tariffs and could, as the Minister said, encourage customers to make the most of charging options during the day. By using the existing wholesale energy costs as a base, it continues to ensure the cost considerations under our pricing framework are met overall (the prices reflect the actual costs retailers are likely to incur).

While this approach would be a departure from the N+R methodology we usually apply, it could be considered and developed further if the Minister were to issue us with a separate delegation in the future, including with the benefit of further policy guidance from the Minister and feedback from stakeholders. We note that as this approach uses existing wholesale energy cost estimates, it could be implemented in a timely manner.

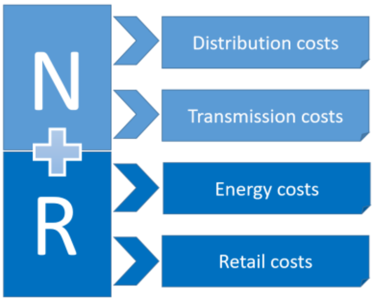
There may be other options, e.g., to set a tariff where the customer pays for wholesale energy costs based on the spot price in the market at the time energy is consumed. This approach would ensure the price signals in the wholesale energy market are directly passed on to the customer, (assuming customers actively monitor the market and manage their energy consumption on this basis). In doing so, this would fully expose customers to the ongoing risk (and volatility) of wholesale energy prices in the NEM. However, this would be inconsistent with our methodology, which assumes a prudent retailer would seek to minimise this risk via appropriate purchasing and hedging strategies. It is also unclear (based on the level of information available), how retailers could implement this in practice at this time.

This approach would be a significant department from the N+R methodology we usually apply and would require detailed guidance from the Minister and input from stakeholders. Given this, such an approach is unlikely to be able to be implemented in a timely manner.

4 INDIVIDUAL COST COMPONENTS

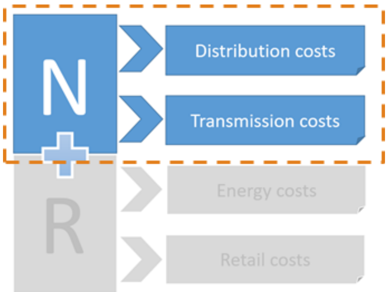
This chapter sets out the individual components of notified prices, including relevant matters we considered when setting them this year. Many of these matters are identified in the delegation and terms of reference, which we must consider when setting notified prices.

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[79], all of which are regulated (and approved) by the AER.

Overall, network costs this year are expected to:

- decrease by 6.7 to 14 per cent for the main small customer tariffs
- increase by 6.5 to 12.7 per cent for the main large customer tariffs.[80]

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[81]

[79] In Queensland, these charges generally include the Solar Bonus Scheme (SBS) and AEMC levy costs.
[80] These changes are based on the annual bills for typical customers.
[81] The Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM.

  - all other retail tariffs—basing the N component on the price level of the relevant Energex charges but utilising Ergon Distribution tariff structures

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

Stakeholder comments

EER supported our approach to setting the N component across the various small and large customer tariffs.[82] 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.[83]

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

Analysis and 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 Ergon Distribution's east zone, transmission region one
- for retail tariffs with no underlying network tariff (tariffs 12A, 14, 22A and 24), using a price indexation methodology, specifically an 'X-factor' approach[84], which allows for the pass-through of AER-approved changes in network costs to customers on these retail tariffs.[85]

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 have removed some tariff options from the suite of notified prices available to customers. While most of these tariffs have been made obsolete, we have determined the network cost component as outlined above (reflecting that some customers may still be on these tariffs until their phase-out date). We have not determined a network cost component for tariff 20A, as this tariff will be extinguished and will not be available in the 2022–23 tariff year.

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[82] EER, sub. 5, p. 9.

[83] Ergon Energy Network and Energex, sub. 4, pp. 2–3.

[84] 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).

[85] Specifically, we used 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.

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

Figure 4.1 Network costs—typical customers on small customer tariffs (incl. GST)

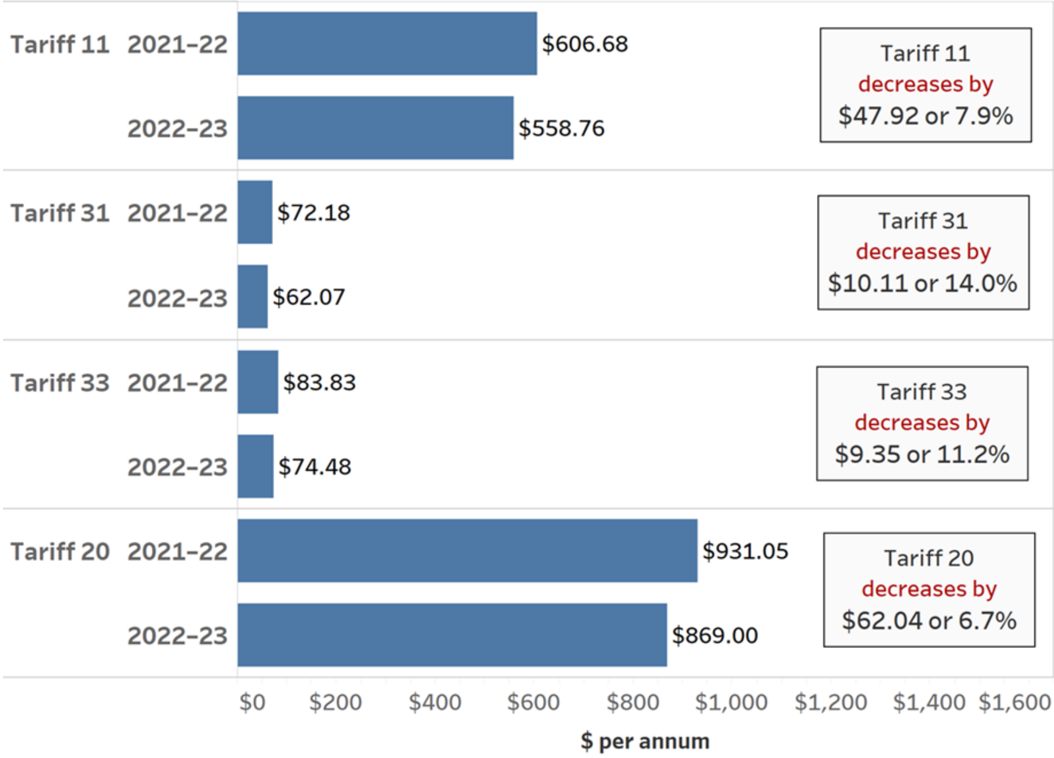
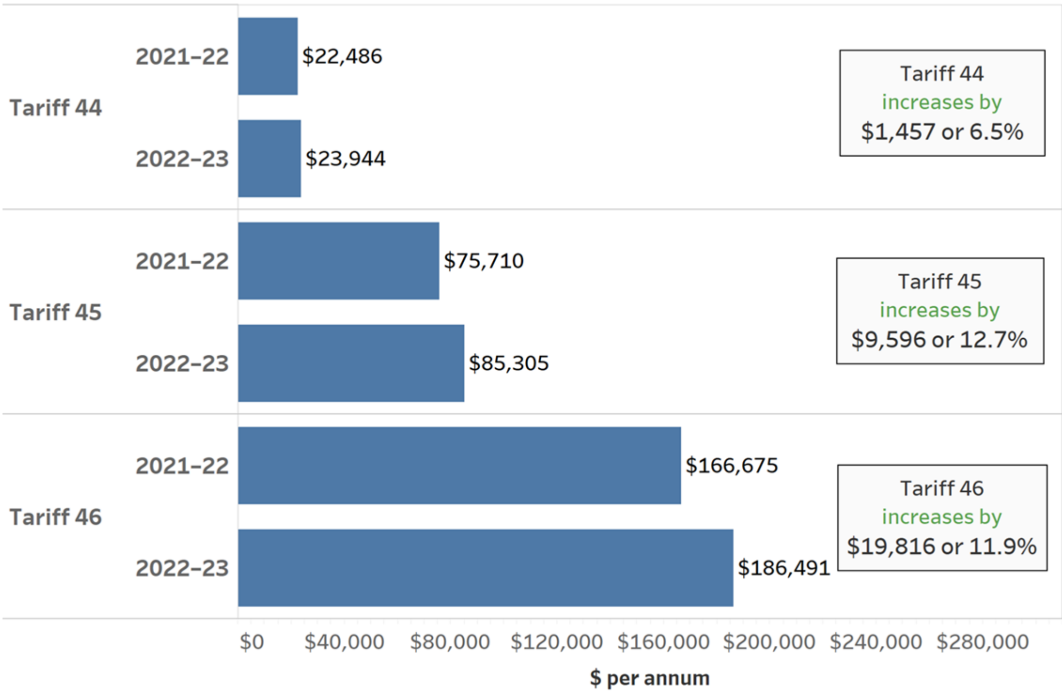


Figure 4.2 Network costs—typical customers on large customer tariffs (incl. GST)



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

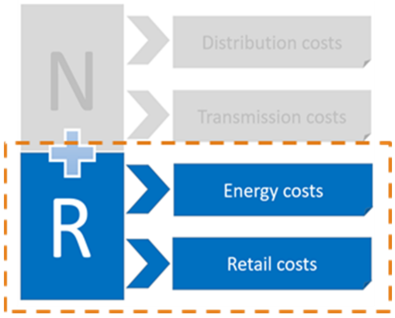
Timing

We used the approved 2022–23 network prices for Ergon Distribution and Energex[86] as the relevant network prices in our calculation of the N component.

Etrog Consulting supported using submitted network prices if the AER has not approved the final prices in time for our final determination. However, it did not support using a pass-through mechanism if needed (to account for any material differences between the submitted network prices and the final AER approved prices). It said each year's prices should be based on the costs of the retailer for that year.[87]

We note Etrog Consulting's comments about our potential use of a cost pass-through mechanism for material differences between proposed and approved network prices, as indicated in our draft determination. However, we have been able to use approved network prices in our final determination, so we have not needed to consider this issue.

4.2 Retail 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 risk they face by operating in the market.

4.2.1 Energy costs

Energy costs include costs associated with wholesale energy costs (the costs of purchasing electricity from the NEM and risk management/hedging using financial instruments), other energy costs and energy losses.

Consistent with previous years, we have engaged ACIL Allen (ACIL) to provide expert advice on energy costs.[88] Our position for this review is to estimate energy costs based on ACIL's advice.

Wholesale energy costs

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

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.[89]

Canegrowers suggested that we should conduct an ex post analysis of the actual energy costs that EER incurred when we estimate wholesale energy costs as part of future determinations. It also claimed that the type of meters that customers hold has no impact on how retailers incur costs when purchasing electricity from the NEM.[90]

[86] As approved by the AER on 13 May 2022.
[87] Etrog Consulting, sub. 16, p. 10.
[88] ACIL Allen, *Estimated Energy Costs*, final report prepared for the QCA, May 2022.
[89] Canegrowers, sub. 2, p. 2, sub. 8, p. 2; Queensland Farmers' Federation, sub. 7, p. 4.
[90] Canegrowers, sub. 2, p. 3, sub. 8, p. 3.

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. It 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.[91]

EER noted that our hedge modelling is heavily weighted towards the use of ASX cap contracts. It considered that such weighting is difficult to achieve in practice. Specifically, EER referenced the low level of open interest[92] in cap contracts (traded on ASX Energy) to support its views. It requested that we reconsider the weighting of cap contracts in our hedging strategy, taking into account current liquidity of these contracts.[93]

EER also:

- highlighted the increasing incidence of negative spot prices within the NEM[94]
- 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[95]
- suggested the publication of ACIL's energy modelling data to help improve assessment and understanding of our methodology for estimating wholesale energy costs.[96]

Cotton Australia was concerned that consumers are shouldering the business interruption costs of a major incident at Callide C via higher wholesale energy costs.[97]

Etrog Consulting expressed its concern regarding higher energy costs and noted that energy transition should result in much lower energy costs as the marginal costs of production of solar, wind and other renewable generation technologies are close to zero. It also suggested that the energy cost methodology should be reviewed at the earliest opportunity.[98]

Analysis and position

Our position is to determine wholesale energy costs based on ACIL's estimates. These estimates were derived using:

- a market hedging approach—such an approach involves simulating a range of expected spot prices that a retailer faces (having regard to the likely variation in demand profiles and generation and supply costs), and then estimating wholesale energy costs for a retailer that hedges spot price risk (through exchange-traded energy derivatives, i.e. ASX Energy contracts[99])

[91] EER, sub. 5, p. 13.
[92] Open interest refers to the number of outstanding contracts that have not been closed (or are still active).
[93] EER, sub. 5, p. 12, sub. 10, p. 1.
[94] EER, sub. 5, p. 12.
[95] EER, sub. 5, p. 13.
[96] EER, sub. 10, p. 1.
[97] Cotton Australia, sub. 9, pp. 2–3.
[98] Etrog Consulting, sub. 16, pp. 14–15.
[99] Generally, the purchase of ASX contracts 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, ASX contract prices incorporate market participants' risk-weighted expectations of future spot prices.

- market data up until 15 April 2022—such an approach takes into account the most current information (including developments over the potentially volatile summer period), while still meeting our final determination timeframe.[100]

As part of each determination, we review the ongoing appropriateness of ACIL's market hedging methodology. More details of our assessment are available in Appendix C. While the latest market hedging approach is broadly similar to those applied in previous years, we consider this approach to be appropriate, noting it:

- closely reflects the prevailing market conditions within the NEM and relevant financial markets (such as the ASX contract markets). This was achieved by using the most up-date data to undertake a large number of simulations to account for potential variation in demand, thermal plant availability, output of renewable generation and spot price outcomes. Further, market participants' expectations were incorporated by using the most recent publicly available ASX contract data
- adequately addresses the issues raised in stakeholder submissions.

Furthermore, ACIL's approach uses the latest available market data—including information on the uptake of rooftop solar PV, renewable energy resource traces[101], 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 we still meet our final 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 is in the public domain.[102] To improve stakeholders' understanding of our methodology for estimating wholesale energy costs, we have also published relevant cost modelling data on our website.[103]

Addressing stakeholders' comments

In relation to Canegrowers' suggestion that we use EER's actual energy costs to inform our future energy cost estimates, we acknowledge that an ex post analysis would be useful to assess the reliability of our estimates. However, retailers' actual cost data tends to be commercial-in-confidence. Further, 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. Despite these challenges, we are working on an ex-post analysis to better assess the reliability of our estimates.

Canegrowers claimed that the type of meters that customers hold has no impact on how retailers incur costs when purchasing electricity from the NEM. However, this view is inconsistent with how the NEM is operated. The average wholesale spot prices that retailers pay for most small business customers are determined using AEMO's regional demand profiles (i.e. the net system

[100] Appendix C provides for a detailed description of ACIL's market hedging approach.
[101] Renewable energy resource traces reflect the availability and quality of renewable resources/generation in different regions, depending on weather and geographical conditions.
[102] The appropriateness of a market hedging approach is discussed further in Appendix C and ACIL's final report.
[103] QCA, *Regulated electricity prices for regional Queensland 2022–23*, QCA website, 2022.

load profiles). These profiles approximate the timing and amount of electricity consumed by customers on accumulation meters. Consequently, we have used these demand profiles when estimating wholesale energy 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.

Regarding the suggestion for a trigger to re-open energy cost estimates for unexpected events, our current delegation does not allow for the reopening of notified prices beyond the regular determination for each financial year. However, retailers reduce their exposure to unexpected market events by engaging in a variety of hedging strategies, including through trading in ASX contracts.

Our market hedging approach is designed to reflect the conditions of ASX contract markets, where retailers lock in a price (or a maximum price[104]) for a given amount of electricity through trading in ASX contracts. The purchase of ASX contracts allows retailers to mitigate some of the impacts of unexpected events by locking in a proportion of their costs. Any unexpected events with longer term implications would likely be reflected in the ASX contract markets, as these markets are forward-looking and reflect market participants' expectations of future spot prices.

In relation to the suggested need to update our energy cost modelling, 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, output of renewable generation and spot price outcomes. On this basis, we are satisfied that our methodology is as up to date as practical, based on the latest available information.

In relation to EER's comment on the liquidity of cap contracts and its effect on the viability of the hedging strategy, we acknowledge the low level of open interest[105] for ASX cap contracts from 2023 onwards. However, open interest, in isolation, is unlikely to be a suitable indicator for liquidity. This is a view shared by ASX Energy, the central exchange for cap contracts. As indicated by ASX Energy, open interest figures are calculated based on reports and revisions made by participants who may not have followed best practice guidelines. Therefore, these figures should not be used as an absolute measure of liquidity in contracts.[106]

Another indirect indicator of contract liquidity would be the cumulative trade volume. Except for 2021–22[107], the cumulative trade volume for cap contracts (to date for 2022–23) is on par with, or higher than, the trade volumes in previous years. For example, compared to 2020–21 (prior to the commencement of 5-minute settlement), trade volume for cap contracts to date for 2022–23 has increased by 109 per cent. On this basis, we are satisfied that the liquidity of markets for cap contracts have remained reasonably stable and that the trade weighted average cap price

[104] Retailers can lock in the maximum price for future electricity purchases by trading in ASX cap contracts.
[105] Open interest refers to the number of outstanding contracts that have not been closed (or are still active).
[106] See ASX Energy, *Options*, ASX website, n.d., accessed 11 May 2022.
[107] In 2021–22, trade volume was lower due to the transition to 5-minute settlement.

continues to be a reasonable proxy for the cost of sourcing cap contracts as part of a broader hedge portfolio.

Further, ASX cap contracts are just one of the many instruments that retailers can use to hedge their exposure to spot prices. In reality, retailers will likely have access to over-the-counter (OTC) contracts[108], power purchase agreements (PPAs)[109] and their own generating units to act as hedging instruments. As such, we do not expect that retailers will satisfy their entire hedge portfolio using solely ASX contracts. The key reason that we rely on ASX contracts is because the information for these contracts is publicly available, transparent and verifiable, whereas information for other hedging instruments tends to be commercial-in-confidence.

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 8 and 12 per cent, compared with 6 per cent in 2021. On this basis, we are satisfied that ACIL's methodology addresses EER's concerns and captures the impacts of negative spot price outcomes during daylight hours.

EER also suggested the publication of energy cost modelling data to improve transparency. In addition to the supporting information provided in our technical appendices, we have published relevant wholesale energy cost modelling data on our website to improve stakeholders' assessment and understanding of our methodology for estimating wholesale energy costs.[110]

Consistent with EER's view, we consider it reasonable to continue to use the NSLP to determine wholesale energy costs, given the current low penetration of smart meters in Queensland.[111] Currently, only around 20 per cent of small customers in Queensland are on smart meters.[112] 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 are investigating the robustness of these data sets.

Cotton Australia was concerned that business costs associated with the outage at Callide C are being borne by customers via higher wholesale energy costs. We note that the costs incurred by the owners of Callide C, such as business interruption, equipment loss and replacement costs, are not incorporated as part of wholesale energy costs. However, the outage at Callide C has contributed to a tighter supply–demand balance, leading to elevated spot prices and ASX contract prices and therefore higher wholesale energy costs.

Etrog Consulting highlighted that the energy transition should result in lower costs of energy, as the marginal costs of renewable generation technologies are close to zero. We note that spot

108 Unlike the standardised exchange-traded ASX contracts, OTC contracts are bilateral agreements and therefore allow for a high degree of flexibility in the terms of the arrangements.

109 PPAs are long-term bilateral contracts between a generator and a purchaser for the sale and supply of electricity. Generators receive payments over the life the PPAs to underwrite their investments. Purchasers of PPAs (such as retailers) can manage the NEM spot price risk by locking in their electricity costs.

110 QCA, *Regulated electricity prices for regional Queensland 2022–23*, QCA website, 2022.

111 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.

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

prices in the NEM are determined using a marginal pricing approach. In other words, the spot price for each 5-minute period is determined by the offer price of the last generator dispatched to meet demand, irrespective of the offer prices of other generators.

Despite recent significant growth in renewable generation, gas and coal-fired power stations continue to be the last generator dispatched and set the spot prices for about 70 per cent of the time in Queensland. This spot price setting dynamic, coupled with higher gas and coal prices, have contributed to elevated spot prices and ASX contract prices, and therefore higher wholesale energy costs.

Summary of key findings

The level of wholesale energy costs is determined by the prevailing market conditions in the NEM and relevant financial markets. Our approach in estimating wholesale energy costs is designed to closely reflect these market dynamics, which are best approximated by publicly available prices and trade volumes of ASX contracts.

In practice, retailers adopt a range of hedging strategies to manage spot price volatility within the NEM[113], including through the purchase of ASX contracts. Generally, the purchase of ASX contracts enables retailers to lock in a price, or a maximum price (in the case of cap contracts), at which a given volume of electricity will be transacted at a future date.

Compared to the estimates from last year, our estimates of wholesale energy costs have increased for both small and large customer tariff classes:[114]

- For the main small customer tariffs, these costs are 40.1 per cent to 52.8 per cent higher
- For the main large customer tariffs, these costs are 38.5 per cent higher.

These changes reflect a significant increase in the trade-weighted prices for ASX base and cap contracts. The increase in ASX contract prices is driven by market participants expecting higher future spot prices and greater price volatility, which is likely due to:

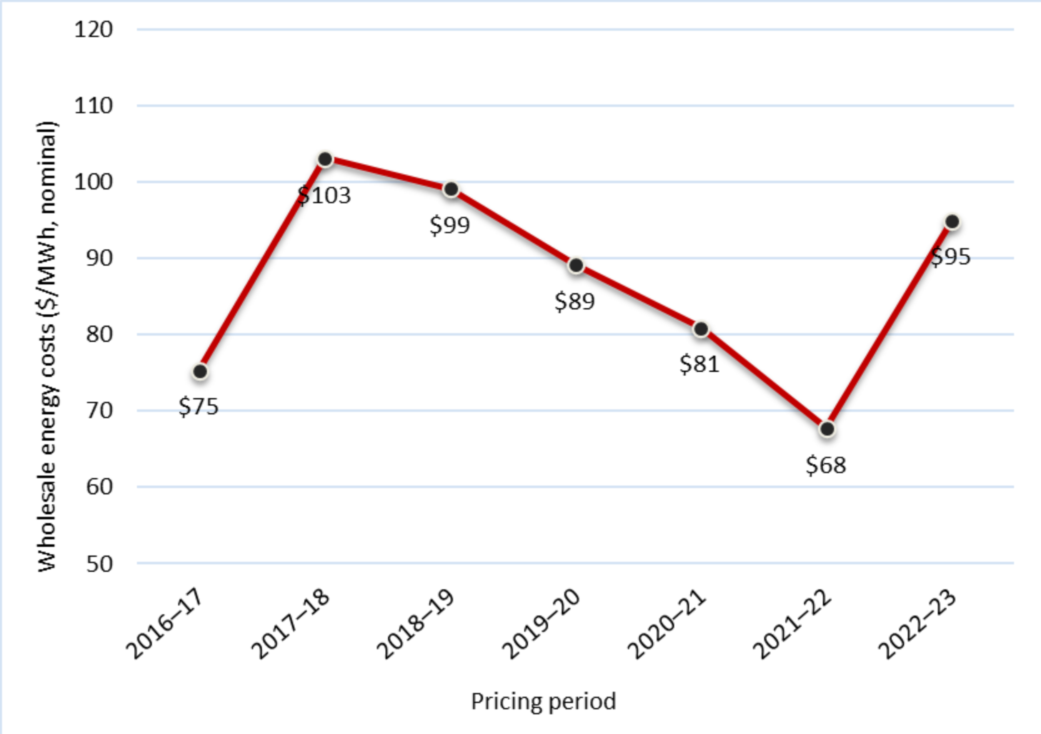
- a slowdown of renewable energy generators coming online (compared to recent years) and the reduced availability of thermal generators—both of which contribute to a tighter supply–demand balance in Queensland
- higher gas and coal prices
- uncertainties faced by cap contract providers around the ability of their peaking plant to cover price spikes in the NEM under a 5-minute settlement.

While wholesale energy costs are estimated to increase substantially compared to last year, this increase should be viewed within the context of declining costs since 2017–18. For example, despite the recent increase in wholesale energy costs for the main small customer tariffs, the 2022–23 costs remain lower than the costs in both 2017–18 and 2018–19 (in nominal terms). Further, the extent of this increase, large as it is, is almost identical in magnitude to the increase that occurred between 2016–17 and 2017–18 (Figure 4.3).

[113] The NEM is a volatile market where spot prices are settled every 5 minutes and currently can range from –$1,000 to $15,100 per megawatt hour (MWh).

[114] As discussed in Chapter 3, our 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.

Figure 4.3 Changes in wholesale energy costs for main small customer tariffs (excl. GST)



Source: QCA's analysis of data from ACIL Allen.

Developments between the draft and final determinations

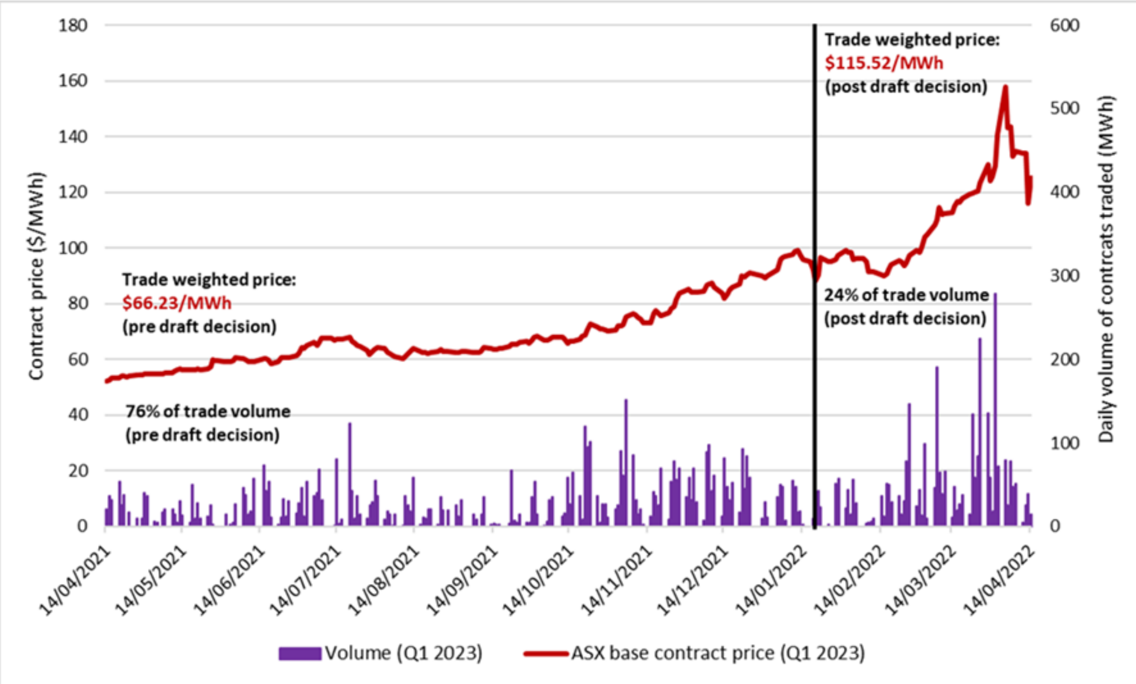
The significant movement in ASX contracts was partially captured in our draft determination with a data cut-off date of 21 January 2022. Trade-weighted prices for the final determination were calculated using prices and volumes of ASX contracts traded until 15 April 2022 inclusive.

Since the draft determination, there is a large increase in the trade-weighted prices of ASX contracts. Since 21 January, trade-weighted prices for:

- quarterly ASX base contracts have increased to a level between $87/MWh and $116/MWh compared to $46 and $66/MWh prior to 21 January
- quarterly ASX cap contracts have increased to a level between $12/MWh and $35/MWh compared to $6 to $26/MWh prior to 21 January.

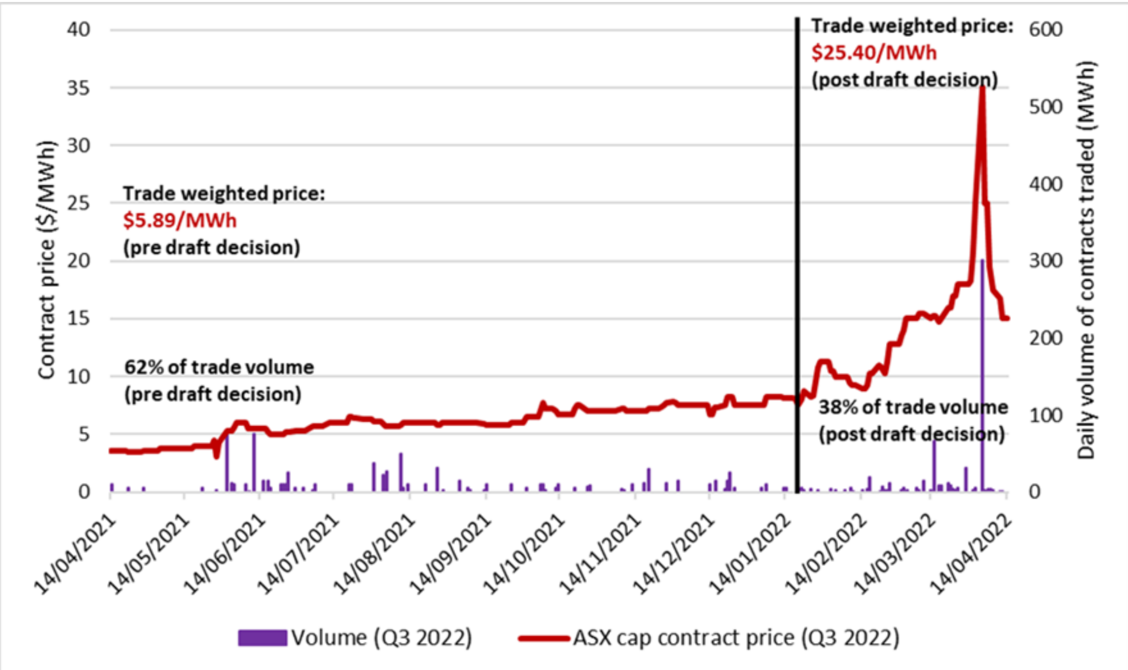
These large increases in ASX contract prices are illustrated in the following figures:

Figure 4.4 Queensland ASX base contract 2022–23 (Q1 2023)



Source: QCA's analysis of data from ASX Energy.

Figure 4.5 Queensland ASX cap contract 2022–23 (Q3 2022)



Source: QCA's analysis of data from ASX Energy.

Market developments since 21 January led market participants to revise their price and demand expectations when trading in ASX contracts for 2022–23. These developments include significant episodes of weather-related high demand coupled with reduced generation availability and higher fuel prices faced by generators, which contributed to higher spot prices and increasing price volatility in Queensland:

- higher demand—parts of Queensland experienced severe to extreme heatwaves in the first week of March, which was the state's fifth warmest on record.[115] This led to demand in Queensland reaching an all-time high of 10,058 MW on 8 March
- reduced thermal generation availability—coal-fired and gas-powered generators in Queensland have suffered from increased unplanned outages. For example, in terms of coal-fired generators, Callide C (unit 4) has remained out of service since its major incident in Q2 2021, while Kogan Creek was out of service for around 26 days due to an unplanned outage. The Swanbank E gas-fired generator has also been out of service for the entire Q1 2022 following damage to the station's voltage regulator in December 2021
- high domestic gas prices to date and higher international commodity prices—domestic gas prices have remained at or near record levels, averaging around $10/GJ in Q1 2022, an increase of 67 per cent, compared to $6/GJ in Q1 2021. International gas prices and thermal coal export prices have been high and volatile during Q1 2022 as the war in Ukraine and sanctions against Russia added uncertainty to markets already impacted by global supply constraints.

  Asian LNG prices have been volatile with a peak price of A$53 per gigajoules (GJ) in Q1 2022, compared to a peak price of less than A$30/GJ in Q1 2021. Thermal coal export prices averaged around A$367 per tonne (t) in Q1 2022, approximately A$116/t higher than Q4 2021, after briefly reaching a record high of A$604/t in early March. Compared to Q1 2021, coal export prices have increased by approximately 250 per cent.[116]

  Further, coal-fired generators in the NEM have been repricing their offers by shifting a substantial amount of supply offered to higher price bands. Compared to Q1 2021, over 3000 MW of capacity from black coal-fired generators was shifted from lower price bands to prices above $60/MWh.

  Despite recent significant growth in renewable generation, gas and coal-fired power plants continue to be the last generator dispatched to meet demand for each 5-minute interval with their offer prices determining spot prices in Queensland.[117] In Q1 2022, coal and gas-fired generators set spot prices around 70 per cent of the time. This spot price setting dynamic, coupled with higher gas and coal prices, has contributed to elevated spot prices and ASX contract prices.

Heatwave conditions, high demand, reduced generation availability, higher fuel prices, and coal-fired generators repricing their offers led to higher spot prices and increasing price volatility in Q1 2022. For example, average spot prices for 1 February and 8 March were amongst the 10 highest daily levels recorded in Queensland since commencement of the NEM.

Since the draft determination, we have also observed a sustained period of high spot prices. Recent monthly average spot prices ranged from $155/MWh to $194/MWh in Q1 2022, compared to average prices between $42/MWh and $49/MWh in Q1 2021.

Not only have average spot prices remained elevated since the draft determination, but there has also been a significant number of high price events (spot prices exceeding $300/MWh). The AER

[115] See Bureau of Meteorology, *Queensland in March 2022,* BoM website, Australian Government, 2022, accessed 11 May 2022.
[116] AEMO, *Quarterly Energy Dynamics Q1 2022*, April 2022.
[117] Spot prices in the NEM are determined using a marginal pricing approach. In other words, the spot price for each 5-minute period is determined by the offer price of the last generator dispatched to meet demand, irrespective of the offer prices of other generators.

reported and investigated 12 cases of 30-minute wholesale electricity prices that breached $5000/MWh in Q1 2022, compared to zero breaches in Q1 2021. Spot prices greater than $300/MWh have contributed from $43/MWh to $92/MWh to the monthly average spot prices for Q1 2022, compared to a contribution of $2/MWh to $7/MWh for Q1 2021.

Other energy costs and losses

Retailers incur other energy costs 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[118]
- 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. These costs have increased substantially since last year due to AEMO activating the RERT scheme more frequently in Queensland. More information is available in the sections below
- 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)
- 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. [119]

Stakeholder submissions

In relation to NEM fees, EER noted:

- the need to recover fees associated with the distributed energy resources (DER) integration program and 5-minute settlement compliance
- that an additional allowance should be provided to account for the step change in upcoming NEM fees due to AEMO's sizable deficit. It suggested that we consult with AEMO on the magnitude of this debt recovery to establish an appropriate allowance.[120]

EER considered that RERT costs must be recovered as part of notified prices, noting that there were two recent RERT activations on 25 May 2021 and 1 February 2022 in Queensland. EER has raised concern over whether the most recent RERT costs would be incorporated in time for our

[118] 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.
[119] At this stage, for 2022–23, the RRO has not been trigged for Queensland; 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 final report.
[120] EER, sub. 5, p. 14, sub. 10, pp. 2–3.

final decision as AEMO is expected to finalise its RERT estimates in May 2022. It suggested that draft estimates published by AEMO should be incorporated into our final decision with any potential under- or over-recovery of RERT addressed using a cost pass-through mechanism.[121]

Etrog Consulting submitted that RERT and RRO costs should not be recovered as part of notified prices as these costs arise due to retailers leaving gaps in their contracting arrangements.[122]

Analysis and position

Our 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 • 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 latest projected fees • 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.[123]

In relation to EER's comments on NEM fees, costs associated with the DER integration program and 5-minute settlement compliance have been incorporated as part of our final decision. We have also consulted AEMO on the magnitude of the step change in the upcoming 2022–23 NEM fees. To assist with our process, AEMO provided a draft document containing updated 2022–23 estimates, which were presented to its financial consultation committee.[124] We have updated our NEM fees using the draft budgeted percentage changes contained in this document.

EER also raised concerns regarding the inclusion of RERT costs incurred on 1 February 2022. We note that these costs have been included in this determination and are based on the latest

121 EER, sub. 10, p. 2.
122 Etrog, sub. 16, pp. 16–18.
123 The appropriateness of these approaches is discussed further in Appendix C and ACIL's final report.
124 See AEMO, *Draft FY2023 Budget & Fees*, presentation to the Finance Consultation Committee, 4 March 2022.

available draft estimates from AEMO.[125] Any potential under- or over-recovery of RERT costs would be a matter for the next determination.

Etrog Consulting noted that RERT and RRO costs should not be recovered as part of notified prices as these costs arise due to retailers leaving gaps in their contracting arrangements. However, this view is not consistent with how the RERT operates. The RERT is designed to relate to physical shortfall of capacity, not a lack of hedging contracts. AEMO uses the RERT to contract for emergency reserves such as physical generation or demand response (that are not otherwise available in the NEM) when there is a critical shortfall in reserves.

At this stage, for 2022–23, the RRO has not been trigged for Queensland and therefore no RRO costs have been incurred. We will consider the appropriate methodology to account for the RRO costs when the RRO is triggered for Queensland.

Compared to the estimates from last year:

- LRET costs have increased by approximately 17 per cent ($0.71/MWh)—driven by an increase in the forward price of large-scale generation certificates
- SRES costs have decreased by about 5 per cent ($0.62/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 131 per cent ($0.64/MWh)— reflecting an increase in costs related to operating the NEM, including costs associated with the 5-minute settlement compliance and DER integration program and AEMO's deficit recovery
- ancillary services charges have increased by approximately 246 per cent ($1.01/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 53 per cent ($0.88/MWh) for small customer tariffs and by about 54 per cent ($0.74/MWh) for large customer tariffs—reflecting higher contract prices and higher expected price volatility in the NEM
- RERT costs have increased by approximately $1.01/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 and heatwave conditions coupled with reduced generation availability on 1 February 2022.

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

- 19.7 per cent ($3.63/MWh) higher for small customer retail tariffs
- 19.3 per cent ($3.49/MWh) higher for large customer retail tariffs.

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

As part of this final determination, we have also updated our estimate of energy losses, based on AEMO's recently published 2022–23 loss factors. Compared to estimates for last year, overall

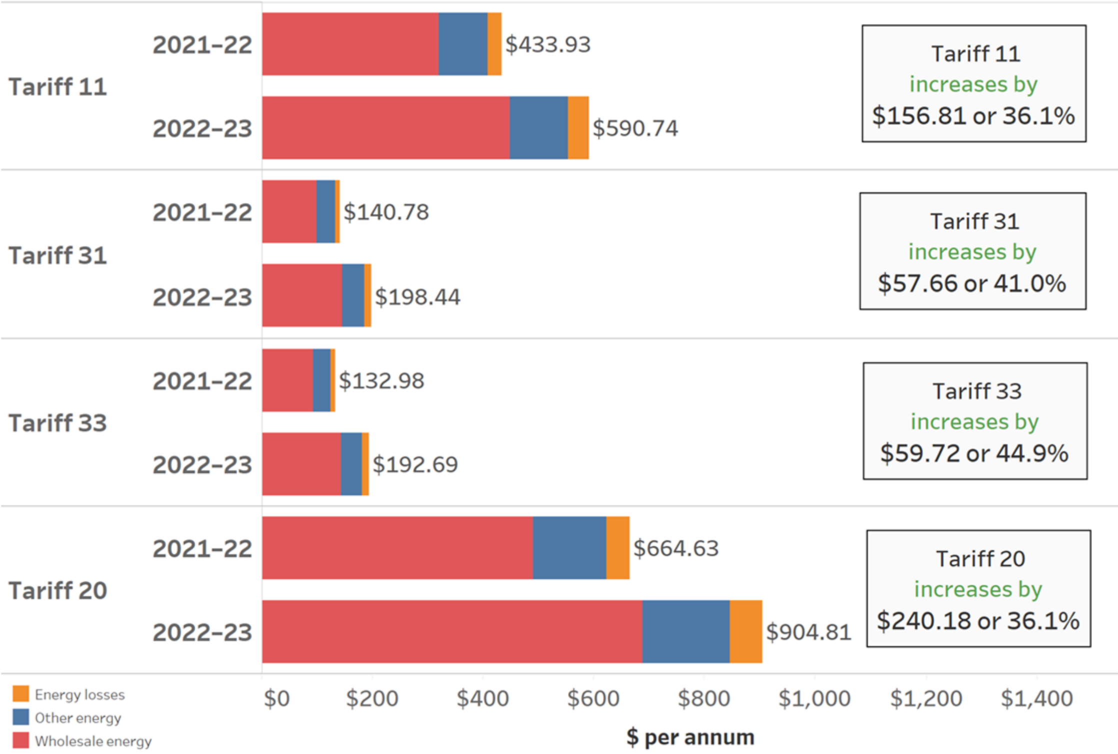
[125] See AEMO, *Estimate payments and volumes for Reliability and Emergency Reserve Trader (RERT) activation on 1 February 2022*, 7 February 2022 and *Update—Estimated intervention event payments for RERT activation on 1 February 2022*, 24 February 2022.

energy loss factors[126] have increased for small and large customer tariffs, reflecting an increase in distribution loss factors.

Total energy costs included in final notified prices

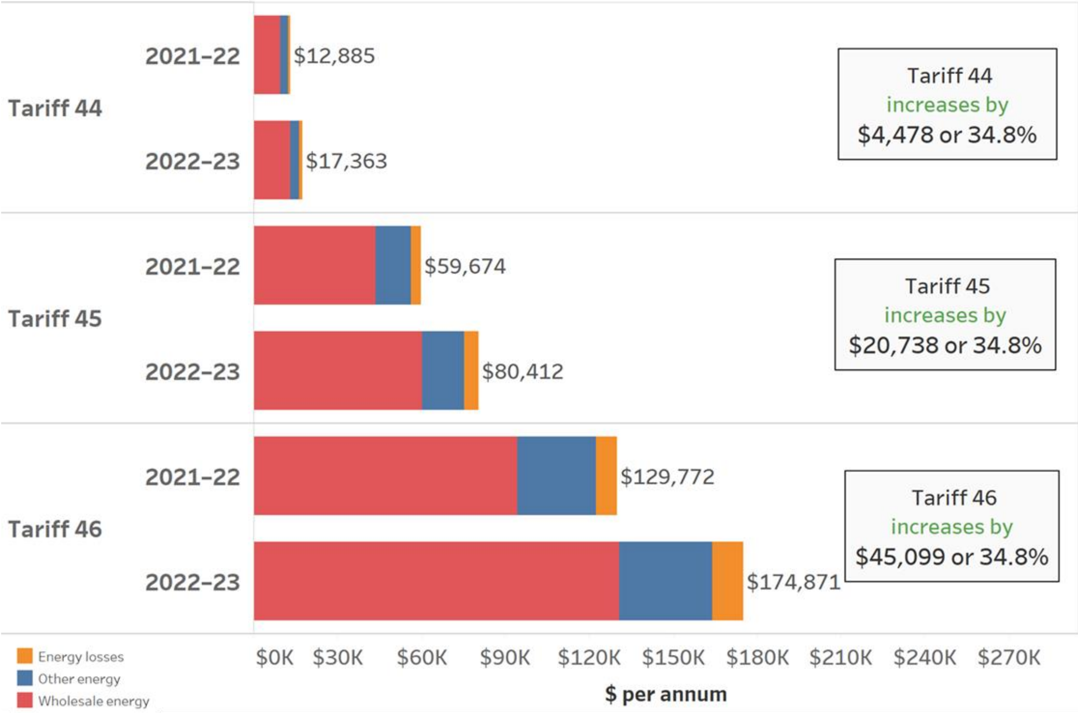
The following charts show the overall energy costs included in final notified prices—compared to last year's estimates—by tariff type for typical small and large customers.

Figure 4.6 Energy costs—typical customers on small customer tariffs (incl. GST)



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

Figure 4.7 Energy costs—typical customers on large customer tariffs (incl. GST)



Note: Amounts are rounded to the closest dollar. Therefore, amounts presented 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 and 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.[127] 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

[127] For further information on this methodology, see QCA, *Regulated retail electricity prices for 2021–22*, technical appendices—final determination, Appendix D, June 2021; and ACIL Allen, *2020–21 regulated electricity price review: Updating retail costs*, final report prepared for the QCA, May 2021.

- maintained the existing retail cost allowance for large customers[128] (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 have maintained our existing retail cost allowances this year, updated to account for inflation.

Stakeholders' submissions

EER said the current retail cost allowances were not sufficient to account for:[129]

- ongoing regulatory reforms and increased compliance costs, including multiple Australian Energy Market Commission (AEMC) rule changes, upcoming regulatory reforms (including, but not limited to the 'Consumer Data Right'[130], 'Better Bill Guidelines'[131] and the Energy Security Board Wholesale Market reforms[132]) 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 that 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.

EER said we should consult with a broad range of retailers to assess the financial impacts of retail compliance with upcoming reforms. It considered that retail cost allowances should be supplemented by a regulatory cost and compliance allowance each year.[133] EER recommended that we review the retail cost allowance every three years.[134]

Etrog Consulting said our approach of escalating the 2021–22 allowances by inflation overestimates retail costs—because a considerable part of retail costs comprises manpower costs, and changes in income are running lower than inflation.[135]

Etrog Consulting said we should compare changes in retail costs from 2016–17 to 2021–22 against inflation and apply an adjustment based on this analysis. Further, it considered an adjustment for productivity improvements should be introduced.[136]

For future years, Etrog Consulting suggested a full bottom-up cost review of retail operating costs should be undertaken.[137]

[128] There was insufficient evidence to vary the existing retail cost allowances for large customers.
[129] EER, sub. 5, pp. 12–14, sub. 10, p. 3.
[130] For more information see Department of Industry, Science, Energy and Resources, *Consumer Data Right for Energy*, Commonwealth of Australia, n.d. accessed 4 May 2022.
[131] For more information see AER, *Better Bills Guideline*, AER website, n.d., accessed 4 May 2022.
[132] For more information see Energy Security Board, *Post 2025 Electricity Market Design*, ESB website, n.d., accessed 4 May 2022.
[133] EER, sub. 5, p. 12, sub. 10, p. 3.
[134] EER, sub. 5, pp. 13–14, sub. 10, p. 3.
[135] Etrog Consulting, sub. 16, p. 17.
[136] Etrog Consulting, sub. 16, p. 17.
[137] Etrog Consulting, sub. 16, p. 16.

Analysis and final position

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

- For small customer tariffs, we have decided to:
  - adjust the 2021–22 fixed retail cost allowances by the Reserve Bank of Australia's (RBA's) forecast of the change in the CPI[138] for 2022–23—to maintain the fixed costs in real terms
  - maintain the variable retail cost allocator at 7.25 per cent for residential customers and 18.7 per cent for small business customers.[139]
- For large customer tariffs, we have decided to:
  - adjust the 2021–22 fixed retail cost allowances by the RBA's forecast change in the CPI
  - maintain the variable retail cost allocator at 6.0445 per cent.[140]

We consider this approach, including use of the RBA's CPI estimate to escalate the fixed retail cost allowances, appropriate. The RBA's CPI estimate has been used for some time and is broadly recognised as appropriate for indexing input costs.

Etrog Consulting said that a considerable part of retail costs comprises manpower costs, but we consider that introducing a tailored index would be administratively complex to develop and is unlikely to improve the accuracy of our retail cost estimate, particularly given we do not have visibility over the breakdown of retail costs (including the portion of labour costs) in south east Queensland.

It is also not clear that historical movements in retail costs provide a good forecast of future movements or a more accurate forecast than the RBA's CPI estimate.

We do not consider any further adjustments are required 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 in relation to regulatory and compliance costs 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, as the reforms are due for implementation in the coming years. We may review this matter (and any evidence provided) in future determinations.

With regards to covid-19, market reports suggest the net impact on the electricity market remains uncertain. Decreases in retail costs (partially due to the decrease in debt collection expenses[141]

[138] We took an average of the RBA's CPI forecasts (for the beginning and end of the notified price period) to derive a value of 4.88 per cent for 2022–23. See RBA, *Statement on Monetary Policy—May 2022*, May 2022, p. 60.

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

[140] This variable retail cost allocator was established in (and has been used since) 2016–17. While we considered establishing new allowances for large and very large customers as part of our 2021–22 review, there was insufficient evidence to vary the existing allocator.

[141] 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.

and customer acquisition and retention)[142,143] have been offset by increases in bad debt (some customers transferring away to other retailers with unpaid debts).[144] Taking into account these factors, there is no conclusive evidence to support any adjustment (either an increase or reduction) to retail cost allowances.

Etrog Consulting said an adjustment for productivity gains should be introduced. We note that this matter was considered in detail in our 2021–22 review. From the limited information available, it could not be concluded that productivity improvements had occurred, with both upward and downward trends reported. Based on the small sample of information available and the absence of a downward trend in these retail costs, we concluded that there was insufficient evidence to justify an adjustment to retail costs for productivity improvements.[145]

Retail cost allowances included in notified prices

The detailed retail costs for each tariff are set out in Appendix G.

The following charts compare the retail cost allowances for 2022–23 with the 2021–22 allowances. The comparison is by tariff type for typical small and large customers.[146] Actual costs will vary for individual customers who have different levels of electricity usage.

[142] This cost for retailers who are not among the big three retailers decreased by 44% from 2017–18 to 2020–21. For the big three retailers, this cost decreased by 27% over the same period. This can be partially attributed to the shift in marketing tactics.
[143] ACCC, *Inquiry into the National Electricity Market—November 2021 report*, November 2021, p. 37.
[144] QCA, *SEQ retail electricity market monitoring 2020–21*, December 2021, p. 152.
[145] For further information, see QCA, *Regulated retail electricity prices for 2021–22*, final determination, June 2021, p. 47; and ACIL Allen, *2020–21 regulated electricity price review: Updating retail costs*, final report prepared for the QCA, May 2021, pp. 29–34.
[146] Data on the consumption of a typical customer was provided by Energy Queensland and Ergon Retail (see Appendix F).

Figure 4.8 Retail costs—typical customers on small customer tariffs (incl. GST)

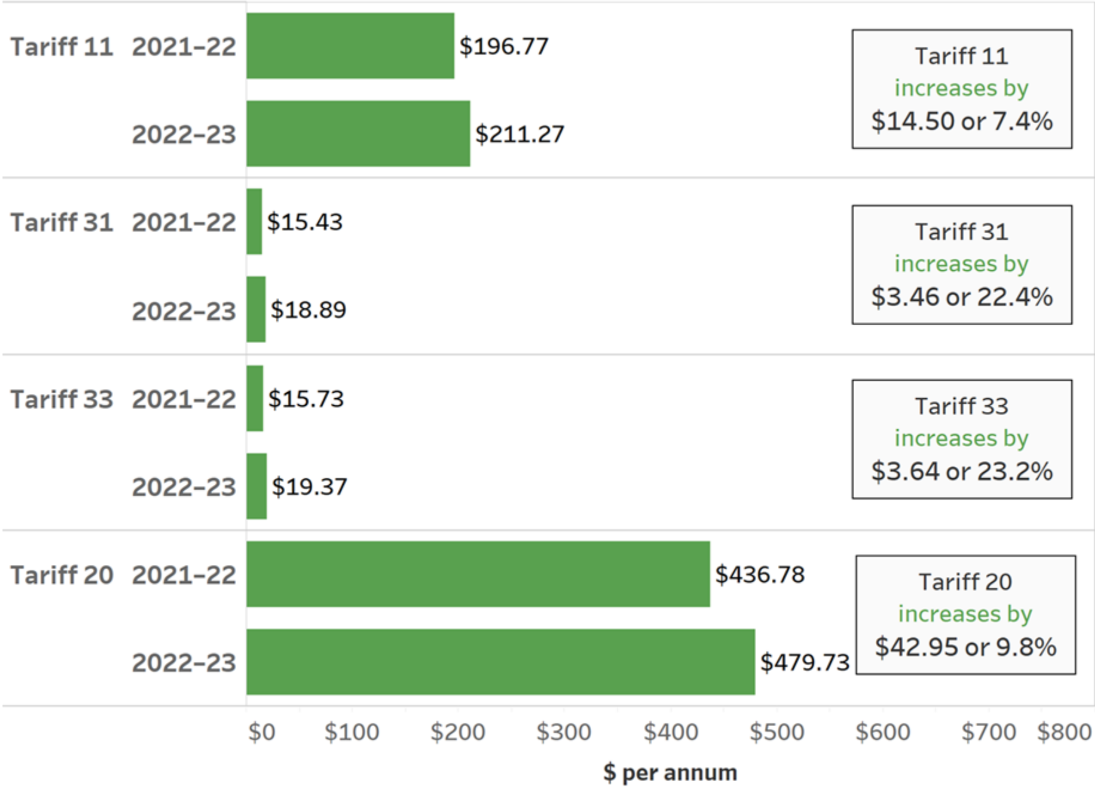
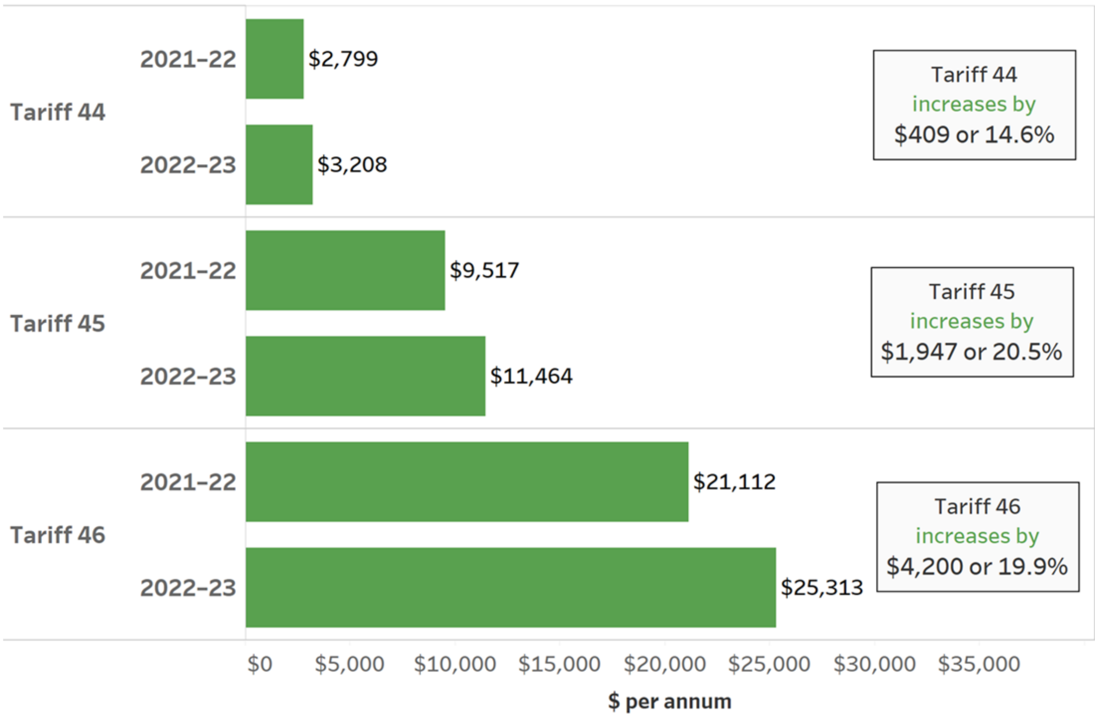


Figure 4.9 Retail costs—typical customers on large customer tariffs (incl. GST)



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

5 OTHER COSTS AND PRICING ISSUES

This chapter sets out our 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

Similar to 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.[147]

In our previous determinations, such considerations have 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
- compare the notified price bill (including the SOA) to the equivalent DMO bill in SEQ and consider discounting the value of the SOA if a notified price bill exceeded the equivalent DMO bill.[148]

In our last determination, we applied a 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 a 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.[149] No adjustment to the SOA was necessary, as the notified price bills did not exceed the equivalent DMO bills.[150]

Given the Minister has asked us to consider similar matters as last year, we have adopted the same approach to set an appropriate SOA to incorporate into small customer notified prices.

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[147] Appendix A (Minister's delegation), covering letter.
[148] Discounts would only occur up until the point where the value of the SOA is zero.
[149] See QCA, *Regulated retail electricity prices for 2021–22: Regional Queensland*, final determination, June 2021, section 5.1.
[150] See QCA, *Regulated retail electricity prices for 2021–22: Regional Queensland, Technical appendices*, final determination, June 2021, Appendix F.

Stakeholders' comments

Some stakeholders considered that a SOA should not be included in notified prices.[151] QEUN said the SOA is not necessary to promote retail competition or to reflect the benefits of an Ergon contract, as is demonstrated by the fact it is used as an 'adjustment tool' for the DMO.[152]

Should regional Queensland customers be required to pay a premium for the additional benefits or protections provided in an Ergon contract, QEUN said this should be quantified by benefit.[153] Further, QEUN said any benefits regional customers gain from standard contracts are offset by the benefit Ergon receives as a monopoly that does not have to compete to acquire or retain customers.[154]

Etrog Consulting noted the delegation does not require us to include a SOA in the notified prices.[155] However, should we determine that it is appropriate to include a SOA, Etrog Consulting said we should consider:[156]

- providing greater transparency of our calculation, because it is unclear how we determined the SOA—it said it has several concerns around our calculations
- the value to customers of any benefits, including by conducting market research. For instance, Etrog Consulting's view is that customers do not place value on the provision prohibiting the charging of late payment fees
- whether the value of standard contract terms has diminished due to broader improvements in retail market offers aimed at protecting customers (which would result in a substantially lower SOA this year).

Separately, stakeholders said notified prices should not exceed the DMO in SEQ, as this would be incompatible with the Queensland Government's UTP.[157]

Analysis and final 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
- make no adjustment to the SOA, as the relevant notified price bills do not exceed the equivalent DMO bills in SEQ.

Inclusion of a SOA

We acknowledge some stakeholders would prefer the SOA not to be included in notified prices. However, we consider it is appropriate to include it at this time, as standard contracts continue to provide some benefits to customers—being more favourable terms and conditions than those typically offered in market contracts. For example, standard contracts include simpler pricing, access to paper bills at no extra cost, better payment terms (which can include bill smoothing)

[151] QEUN, sub. 15, p. 19; Etrog Consulting, sub. 16, p. 18.
[152] QEUN, sub. 15, p. 19.
[153] QEUN, sub. 15, p. 19.
[154] QEUN, sub. 15, p. 19.
[155] Etrog Consulting, sub. 16, p. 18.
[156] Etrog Consulting, sub. 16, pp. 18–21.
[157] Canegrowers, sub. 2, p. 3; QFF, sub. 7, p. 5.

and ongoing certainty of terms (i.e. retailers cannot change terms or impose restrictions, as they can under market contracts).

SOA value

We consider it appropriate to adopt the same approach as last year to determine the SOA, updating the value of the SOA to take account of more recent market data.[158]

Using 2020–21 SEQ market data[159], we:

- assessed the range of fees and total charges in retail market contracts
- 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, on average, around $52[160] 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.

Our adoption of a quantitative approach is important, as it reduces the role of subjectivity in such an assessment. Other possible approaches—such as using market research to survey customer value, as Etrog Consulting suggested, or considering offsetting factors, as QEUN commented—would likely introduce greater levels of subjectivity and may not reflect what is occurring in the market.[161]

Our approach to determine the value of the SOA is also relatively clear and straightforward, providing greater transparency for stakeholders. In this regard, we note that transparency continues to remain a concern among some stakeholders. To provide greater clarity, we have therefore also included an appendix setting out our SOA approach (see Appendix D).

As noted by Etrog Consulting, our 2021–22 price determination observed that recent regulatory reforms aimed at improving protections for customers may have diminished the benefits provided by standard contract terms and conditions.[162] This was reflected in our quantitative assessment of the SOA, which produced a SOA of 3.6 per cent.[163]

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[159] QCA, *SEQ retail electricity market monitoring 2020–21*, December 2021, chapter 4.

[160] This approximate increase of $1 from our draft determination is due to the correction of minor inconsistencies in our calculations.

[161] In support of its proposed approach, Etrog Consulting said that standard contract customers place no value on the provision which states they cannot be charged late payment fees, because no complaints were made when these fees were incorrectly charged. However, a lack of complaints does not necessarily mean customers ascribe zero value to this benefit. There could be a number of reasons why a complaint was not made—for example, the costs associated with making the complaint (time costs, etc.) may simply have outweighed the value of the benefit.

[162] QCA, *Regulated retail electricity prices for 2021–22: Regional Queensland, final determination*, June 2021, p. 57.

[163] The SOA of 3.6 per cent represented a reduction from previous determinations, where a SOA of 5 per cent was applied.

The SOA value of 3.7 per cent this year is largely consistent with the level of adjustment incorporated into notified prices last year and supports the view that the terms and conditions attached to standing offer contracts still provide some value to small customers.

Accordingly, we have incorporated a SOA of 3.7 per cent (of total costs) into small customer notified prices this year.

DMO comparison

As the delegation requires us to consider the government's UTP, consideration must be given to the DMO in determining notified prices. Should the notified price bill (including a SOA) exceed the equivalent DMO bill, we may consider adjusting the SOA to ensure customers in regional Queensland do not pay more than a retailer may charge in south east Queensland.

We have not made any changes to the level of the SOA based on our comparison of notified prices with the equivalent DMO bill. No customer bills based on final notified prices exceeded their equivalent DMO bills in SEQ.

Based on our comparison, notified price bills for tariffs 11 and 20 are approximately $66 and $85 less than the equivalent DMO bills.

Further detail on our DMO comparison is provided in Appendix D, including the adjustments we made to ensure a like-for-like comparison.

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 have provided for the pass-through of Small-scale Renewable Energy Scheme (SRES) costs in this determination.

EER queried whether certain NEM[164] and reliability and emergency reserve trader (RERT) fees levied by AEMO should also be recovered via the cost pass-through mechanism,[165] 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.

At the time of this final determination for 2022–23 notified prices, only the SRES liabilities for the first half of the financial year are known, while liabilities for the second half have been 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

[164] Specifically, NEM fees related to the 5-minute settlement compliance and distributed energy resource integration program.
[165] EER, sub. 5, p. 12, sub. 10, p. 2.

account for the over- or under-recovery SRES costs, we have applied a cost pass-through mechanism.

Analysis and final position

For the final determination, ACIL 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 E.

We have incorporated 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.

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.

5.3 Metering costs

Small customers

The delegation this year again 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.[166] 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.[167]

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

[166] Canegrowers, sub. 2, p. 3; QFF, sub. 7, p. 5.
[167] EER, sub. 5, p. 15.

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

5.4 Additional issues raised by stakeholders

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

Table 5.1 Additional issues raised in stakeholder submissions

Stakeholder comment	***Our response***
Policy matters Stakeholders raised concerns around: • reporting on government policies and addressing issues of subsidy payment (e.g. the Queensland Government's community service obligation (CSO)) • costs associated with the Solar Bonus Scheme • addressing affordability of energy in conjunction with water prices • customer demand thresholds levels, including those associated with the non-reversion policy.[168] Stakeholders recommended we conduct ex-post assessments of Ergon retail and said there was a need for tariff reform.[169] They said that we need to take a larger role in co-ordination of the overall energy transition and called for investment in new power generation and the addition of new energy producers and retailers.[170]	We have previously set out the scope of our review, including the framework in which we operate and set notified prices (see section 1.2). Being delegated the task of setting notified prices by the Minister does not unlock investigative and decision-making powers for us 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 legislated 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). In the context of stakeholder comments, we have discussed affordability in section 3.1.3.
Access to load control tariffs While understanding the need to establish a standardised regulatory framework for load control, QFF said obsolete tariff arrangements have left some customers with little options, other than to obtain tariffs less suitable and at a higher charge.[171] Cotton Australia said tariffs 33, 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. Either the tariff should be offered without Ergon activating actual load control, or Ergon should invest in alternative internet-based load control systems.[172]	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 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 Energy Queensland about options for tariffs that would meet their circumstances.

[168] BRIG, sub. 1, pp. 1–2; Canegrowers, sub. 2, pp. 3–4, sub. 8, p. 3; Cotton Australia, sub. 3, p. 4; PVW, sub. 6, pp. 1–2; QFF, sub. 7, pp. 2, 4, sub. 11, p. 5; QEUN, sub. 15, p. 26.
[169] Canegrowers, sub. 8, pp. 2–3; QFF, sub. 11, pp. 3, 4.
[170] Etrog, sub. 16, p. 3; NIC, sub. 12, p. 1.
[171] QFF, sub. 11, p. 4.
[172] Cotton Australia, sub. 3, p. 4.

Stakeholder comment	***Our response***
Pricing matters Stakeholders raised concerns around the structure and level of network charges and requested us to set capped rates at: • 16 c/kWh, based on network costs and retail costs not exceeding 8 c/kWh.[173] • 14 c/kWh for off-peak prices for tariffs 34 and 22A.[174]	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 review and would not be consistent with the N+R approach and the Queensland Government's UTP (section 3.1).
Kilovolt-ampere demand charging EER proposed the tariff schedule should be amended to remove provisions which allow a customer 12 months to move onto kVA demand charging (where applicable for a tariff) when: • the customer's meter is upgraded from a type 6 to type 1 meter; or • the customer moves from an obsolete to a standard retail tariff. 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.[175]	We consider it appropriate to maintain these provisions at this time, as 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.
Requirements under the QCA Act Stakeholders raised concerns about the impact of our price determination and said that we must consider the matters set out under s. 26 of the QCA Act.[176]	Section 26 of the QCA Act lists various matters we must consider when undertaking an investigation of a declared 'monopoly business activity'. This applies to investigations we conduct under part 3 of the QCA Act, which is a price investigation regime that is recommendatory in nature. Investigations under part 3 of the Act are commenced through the referral of the monopoly business activity by the Minister responsible for the QCA Act (the Treasurer).[177] Part 3 (including s. 26) of the QCA Act are not relevant to the making of this price determination. This determination is made under the Electricity Act via a delegation from the Minister responsible for the Electricity Act.[178] We have considered all relevant requirements in the making of this determination. We understand stakeholders' concerns about the impact of our price determination – we discuss our approach to setting notified prices, including our consideration of the N+R framework and the Queensland Government's UTP, in section 3.1.

[173] BRIG, sub. 1, p. 1; Canegrowers, sub. 2, p. 3, sub. 8, p. 3; QFF, sub. 7, p. 2, sub. 11, p. 2; NIC, sub. 12, p. 1.
[174] Canegrowers, sub. 2, p. 4; PVW, sub. 6, p. 2; QFF, sub. 7, p. 3.
[175] EER, sub. 5, p. 16.
[176] QFF, sub. 11, p. 4; QEUN, sub. 15, p. 11.
[177] For example, our investigations about urban and rural water supply are conducted under part 3 of the Act.
[178] The Minister for Energy, Renewables and Hydrogen.

Stakeholder comment	***Our response***
Stakeholder consultation QEUN raised concerns with the consultation process, believing business and residential customers were unaware of price rises that would impact their budgets and stating it was unclear how stakeholder input affected decisions.[179] QFF said the scope of our review should be extended, for further consultation with stakeholders.[180] Etrog Consulting was complimentary of the online workshop we held. It said we should continue to hold online workshops post-covid, as it allows for the attendance of stakeholders who may not have the resources to attend an in-person meeting.[181]	Consultation is an integral part of our decision-making process, and we invite all stakeholders, including members of the community, to participate in our review. Throughout our review we have sought to engage with stakeholders on a number of occasions, including by inviting submissions from interested parties (on our interim consultation paper and draft determination) and holding a virtual information session, where stakeholders were able to submit questions. That said, we continue to seek to improve our approach and take on-board stakeholder feedback. In our 2021–22 price determination, we provided evidence of stakeholder views influencing matters relevant to our determinations over time.[182] This year, we have considered stakeholder comments and provided responses throughout this final determination. The scope of our review is determined by the legislative framework and the terms of the Minister's delegation. More broadly, we consider consumer and industry groups, also play an important role in ensuring their members (or the customers they represent) are informed and know where to find further information and resources.
Network prices Canegrowers said network charges did not reflect the fact irrigators are low-cost users of electricity who operate on non-congested parts of the Ergon network. It recommended we determine prices for small business interruptible supply tariffs and small business TOU tariffs to encourage irrigators and other small businesses to act as solar sponges.[183]	As is set out in the delegation, we set tariffs using the N+R cost build-up approach. This means we base the network cost component of the retail tariffs on the relevant AER-approved network costs. Under this framework, we cannot alter network tariffs to offer retail tariffs suggested by stakeholders. Solar soaker tariffs are discussed in section 3.2.2.

[179] QEUN, sub. 15, pp. 11–12.
[180] QFF, sub. 11, p. 3.
[181] Etrog, sub. 16, p. 1.
[182] See QCA, *Regulated retail electricity prices for 2021–22*, final determination, June 2021, p. 61.
[183] Canegrowers, sub. 8, p. 2.

6 NOTIFIED PRICES

This chapter sets out the notified prices for 2022–23. Further information is contained in:

- Appendix G, which includes a breakdown of the notified prices by cost component
- Appendix H, which includes the gazette notice with notified prices published in a tariff schedule, and the eligibility criteria and terms and conditions for accessing each tariff.

Table 6.1 Notified prices for residential customers, 2022–23 (excl. GST)

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)	90.408	22.135				
Tariff 12B—residential time-of-use[b]	90.408	17.235	17.946	29.935		
Tariff 14A—residential time-of-use demand[c]	90.408	17.858			3.801	
Tariff 14B—residential time-of-use demand[c]	90.408	16.729			7.920	
Tariff 31—night rate (super economy)		15.696				
Tariff 33—controlled supply (economy)		17.400				
Tariffs to be made obsolete from 1 July 2022						
Tariff 12A—residential (time-of-use)[d]	72.051	19.736		55.287		
Tariff 14—residential seasonal (time-of-use demand)[e]	44.127	16.308			7.155	49.821

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 Notified prices for small business customers, 2022–23 (excl. GST)

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)	123.140	25.408			
Tariff 24A—business (time-of-use demand)[b]	123.140	22.255		4.041	
Tariff 24B—business (time-of-use demand)[b]	123.140	21.024		10.394	
Tariff 34—business (interruptible supply)	113.599	19.132			
Tariff 91—unmetered		22.586			
Tariffs to be made obsolete from 1 July 2022					
Tariff 22A—business (time-of-use)[c]	113.298	24.476	58.907		
Tariff 24—business (time-of-use demand)[d]	59.315	18.868		7.535	74.985
Tariff 41—low voltage (demand)	609.389	16.531		19.307	

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 Notified prices for small business customers, 2022–23 (excl. GST)

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]	123.140	152.798	182.456	212.114	241.773	19.117	24.617	34.939

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 Notified prices for large business and street lighting customers, 2022–23 (excl. GST)

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)	4169.682	14.747		24.161		21.744	
Tariff 45—over 100 MWh medium (demand)	13570.740	14.747		23.140		20.826	
Tariff 46—over 100 MWh large (demand)	35392.202	14.747		18.954		17.058	
Tariff 50A—large business time-of-use demand[b]	17511.840	14.819				14.865	2.973
Tariff 60A—large business flat-rate interruptible supply (primary)	4169.682	23.355					
Tariff 60B—large business flat-rate interruptible supply (secondary)		23.355					
Tariff 71—street lighting		28.402					
Tariffs to be made obsolete from 1 July 2022							
Tariff 50—over 100 MWh seasonal time-of-use (demand)[c]	3510.840	16.965	13.191	10.887	71.447		

***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 Notified prices for very large business customers, 2022–23 (excl. GST)

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)	24565.475	13.122	6.771	3.672	3.516
Tariff 51B—high voltage (CAC 33 kV)	17577.975	13.122	6.771	4.486	3.643
Tariff 51C—high voltage (CAC 22/11 kV Bus)	16367.675	13.122	6.771	5.174	4.417
Tariff 51D—high voltage (CAC 22/11 kV Line)	15676.075	13.122	6.771	10.029	8.908
Tariff 53—high voltage (ICC)	24371.755	13.122		3.672	3.516
ICC site-specific—high voltage	2609.455	11.544		0.209	0.200

Table 6.6 Notified prices for very large business customers, 2022–23 (excl. GST)

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)	12823.075	13.231	12.423	6.771	6.357	13.681
Tariff 52B—high voltage (CAC STOUD 22/11 kV Bus)	12823.075	13.231	12.423	6.771	4.492	46.872
Tariff 52C—high voltage (CAC STOUD 22/11 kV Line)	12823.075	13.231	12.423	6.771	8.223	72.720

Table 6.7 Notified prices for large business customers, 2022–23 (excl. GST)

Retail tariff	*Fixed*	*Usage[a]*	
		Below threshold	*Above threshold*
	c/day	*c/kWh*	*c/kWh*
Tariff 43—Business customer (over 100 MWh)	4169.682	14.748	23.692

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

Table 6.8 Limited-access obsolete tariffs for small business customers, 2022–23 (excl. GST)

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]	106.184	59.998	50.485	20.158		
Tariff 65A—time-of-use tariff[b]	105.884	47.377		25.359		
Tariff 66A—dual-rate demand tariff[c]	223.984			24.004	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 7.5 kW.*

Table 6.9 Metering charges for small customer advanced meters, 2022–23 (excl. GST)

Description	***Charge type***	***Metering charge (c/day)***
Primary tariff	Capital	7.353
	Non-capital	3.447
Secondary tariff	Capital	2.123
	Non-capital	1.025

Source: Data from Energy Queensland.

Table 6.10 Metering charges for large and very large business customer advanced meters, 2022–23 (excl. GST)

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.