Queensland Competition Authority

Draft determination

Regulated retail electricity prices in regional Queensland 2023–24

March 2023

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SUBMISSIONS

Closing date for submissions: 14 April 2023

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (QCA). Submissions are invited on our draft determination of notified prices for 2023–24. The QCA will take account of all submissions received within the stated timeframes.

Submissions, comments or inquiries regarding our draft determination should be directed to:

Queensland Competition Authority
GPO Box 2257
Brisbane Q 4001

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

Confidentiality

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

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

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

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

Public access to submissions

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

Contents

1 ABOUT OUR REVIEW

1.1 Setting notified prices for 2023–24

We have received two delegations from the Minister for Energy, Renewables and Hydrogen (the Minister) to set regulated retail electricity prices (notified prices) and new retail tariffs to apply in regional Queensland in 2023–24.[1] The delegations were issued in accordance with s. 90AA of the *Electricity Act 1994* (Qld) (the Electricity Act).

1.2 Review scope

The purpose of this review is to set notified prices, including two new retail tariffs, to apply in 2023–24, having regard to relevant factors in s. 90(5)(a) of the Electricity Act, namely:

- 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.[2]

The Minister's delegations state the terms of reference for our review, including:

- the period—the price determination is to apply from 1 July 2023 to 30 June 2024
- the timeframes—we are to publish reports and make a draft and a final price determination, with the final price determination due by 9 June 2023
- the pricing methodology—we are to set notified prices having regard to the network plus retail (N+R) cost build-up methodology (some additional considerations apply to the new retail tariffs)
- particular policies or principles—we are to set notified prices having regard to, among other matters, the Queensland Government's uniform tariff policy (UTP)
- consultation—we are required to consult at various stages before making the final determination.

1.3 Draft determination

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

Consultation is an integral part of our decision-making process, and we encourage all stakeholders, including members of the community, to participate in our review. Stakeholders

[1] Both delegations are provided in Appendix A.
[2] We may also have regard to any other matter we consider relevant (s. 90(5)(b) of the Electricity Act).
[3] As required in cl. 8 of the Schedule in the terms of reference (Appendix A). Bundled prices combine the individual cost components (e.g. network costs and other costs—see chapters 4 and 5) that make up the draft notified prices.
[4] We received six submissions in response to our ICP. They are listed at the end of this report and are available on our website.

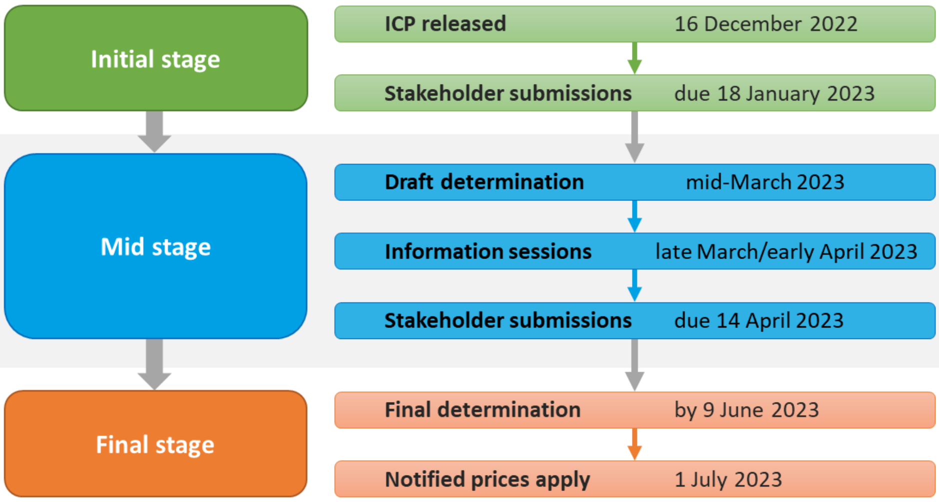
are invited to attended one of our information sessions and provide comments on our draft determination via written submissions.[5]

Submissions on the draft determination are due by 14 April 2023.

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

1.4 Key dates

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



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

1.5 Human Rights Act declaration

As required by the *Human Rights Act 2019* (Qld) (s. 58), we have considered the compatibility of our draft determination with human rights. Our draft 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 the Queensland Government's UTP, which 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.[6]

[5] Information on making a submission, including our submission policy and online submission form, is available on our website.
[6] Appendix A: Minister's delegation, terms of reference, cl. 2(a).

Because of this policy, the electricity prices for most customers in regional Queensland are set below the actual cost of supply. As such, the above-mentioned rights will not be limited by our decision. We are of the view that this draft price determination is compatible with human rights under s. 8(a) of the Human Rights Act.

1.6 Report structure

The draft determination is structured as follows:

- Process and timing of our review (chapter 1)
- Indicative customer bill impacts (chapter 2)
- Overarching framework—including our approach for setting prices (chapter 3)
- Cost build-up components—individual cost elements (chapter 4)
  - Network component (section 4.1)
  - Retail component (section 4.2)
- Other costs and pricing matters (chapter 5)
- Draft notified prices (chapter 6)
- Stakeholder submissions and references.

1.7 Supporting documents

The following additional information is available on our website.

Technical appendices

The technical appendices provide the Ministerial delegations, further analysis and other relevant information as follows:

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

Information booklet

We have prepared an information booklet to accompany the draft determination—it provides an overview of the key issues for setting notified prices this year (as contained in this report).

Consultant’s report

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

2 INDICATIVE CUSTOMER BILL IMPACTS

Overall, typical customers[7] on all major tariffs can expect an increase in their electricity bills in 2023–24, largely due to an increase in wholesale energy costs and (to a lesser extent) other cost components.

This chapter includes:

- indicative customer bill impacts, with comparisons to bills using 2022–23 notified prices
- a snapshot of the key elements driving increases in draft notified prices this year.[8]

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

2.1 Small customers

The indicative bills for the main small customer tariffs include the cost of metering services, consistent with our requirements under the delegation this year (see section 3.2.2). We have included relevant comparable metering costs in the 2022–23 bills to enable stakeholders to compare bills on a like-for-like basis.

Residential customers

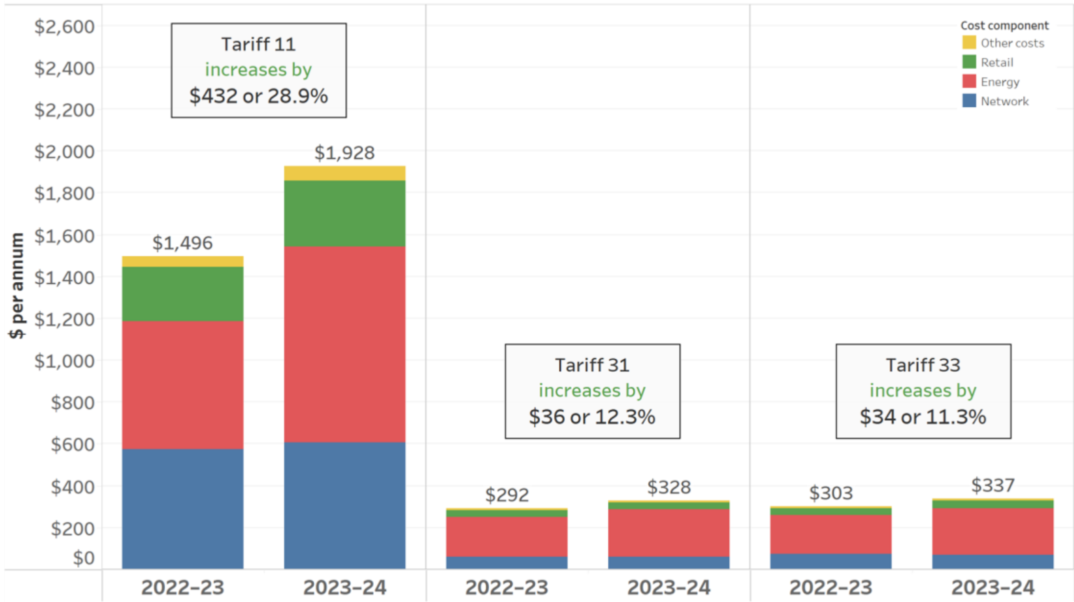
Typical customers on the main residential tariffs (tariffs 11, 31 and 33)[9] are expected to pay around 11.3 to 28.9 per cent more for their electricity in 2023–24.

[7] The typical customer for a given tariff is the median or middle customer in terms of consumption among all customers in regional Queensland on the same tariff. Consumption data was provided by Ergon Retail (see Appendix D).

[8] See chapters 4 and 6 for detailed information on the individual cost components and draft notified prices (respectively).

[9] Most residential customers are on tariff 11 (a flat-rate tariff), 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).

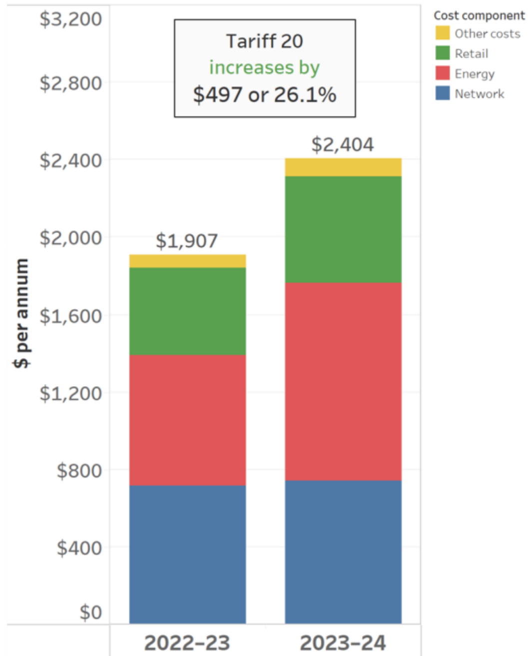
Figure 2.1 Residential customer bill comparison, 2022–23 and 2023–24 (incl. GST)[10]



Small business customers

Typical customers on the main small business tariff (tariff 20)[11] are expected to pay around 26.1 per cent more for their electricity in 2023–24.

Figure 2.2 Small business customer bill comparison, 2022–23 and 2023–24 (incl. GST)[12]

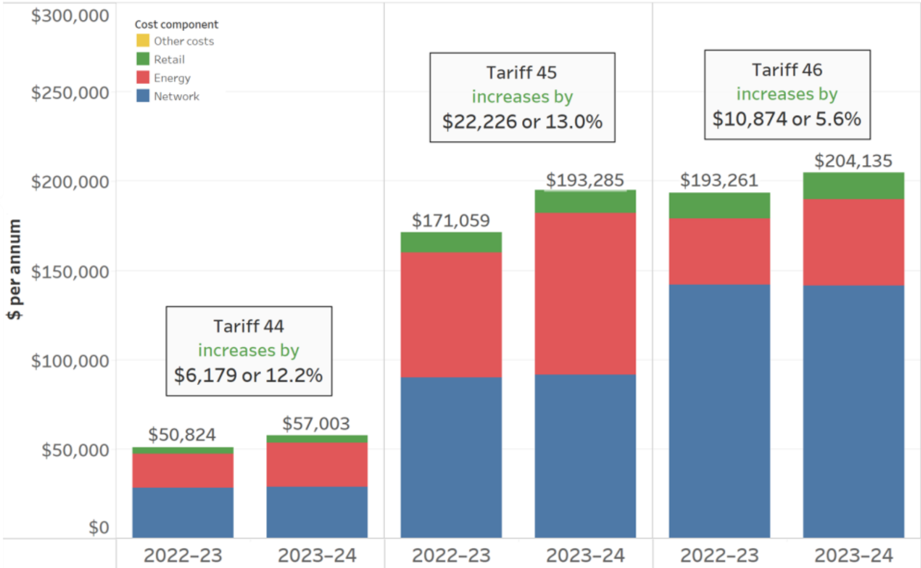


[10] Amounts are rounded to the closest dollar. Percentage changes are based on unrounded amounts. Metering costs are included to facilitate a like-for-like comparison of bills. Bills are based on the consumption of a typical customer with a median annual consumption.
[11] Tariff 20 is a flat-rate tariff.
[12] Amounts are rounded to the closest dollar. Percentage changes are based on unrounded amounts. Metering costs are included to facilitate a like-for-like comparison of bills. Bills are based on the consumption of a typical customer with a median annual consumption.

2.2 Large customers

Typical customers on tariffs 44, 45 or 46 are expected to pay around 5.6 to 13 per cent more for their electricity in 2023–24. Bill increases are lower for large customers due to smaller increases in wholesale energy costs compared to small customers (see section 4.2.1). This is because large customers have flatter consumption profiles[13], which are less expensive to hedge.[14]

Figure 2.3 Large business customer bill comparison, 2022–23 and 2023–24 (incl. GST)[15]



2.3 Reasons for the increase in notified prices

Increases in this year's notified prices are the result of increases in the costs that retailers face. Energy costs—in particular, *wholesale* energy costs—are estimated to increase significantly compared to last year (see section 4.2.1). Wholesale energy costs are the costs that retailers incur when purchasing electricity from the National Electricity Market (NEM).

The NEM has been experiencing extraordinary volatility and uncertainty recently, driven by both international and domestic events, primarily:

- higher gas and coal prices. Thermal generators have been facing higher fuel costs, primarily due to the war in Ukraine and energy sanctions imposed on Russia. These developments have added further uncertainty to energy markets already impacted by global supply constraints, which led to high and volatile gas and thermal coal prices[16]
- uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland region. For example, Kogan

[13] Large customers generally tend to consume a greater proportion of their energy during the day than the night, compared to small customers, leading to flatter consumption profiles.
[14] See section 4.2.1 for further information on how we estimate wholesale energy costs, including the hedging strategies retailers use (e.g. purchasing ASX contracts) to manage spot price risk when purchasing electricity from the national electricity market.
[15] Amounts are rounded to the closest dollar. Percentage changes are based on unrounded amounts. Metering costs are excluded. Bills are based on the consumption of a typical customer with a median annual consumption.
[16] Domestic prices of coal and gas are influenced by international prices because some producers may have the option of exporting these resources and receiving international prices. As such, thermal power stations compete with international buyers, and this affects the fuel costs of these generators.

Creek and Callide C have suffered from major outages and delays in their return to service, due to unforeseen circumstances.

These events have placed upward pressure on wholesale energy prices and are important determinants of Queensland retailers' energy costs and of the wholesale cost of energy in the NEM more broadly.

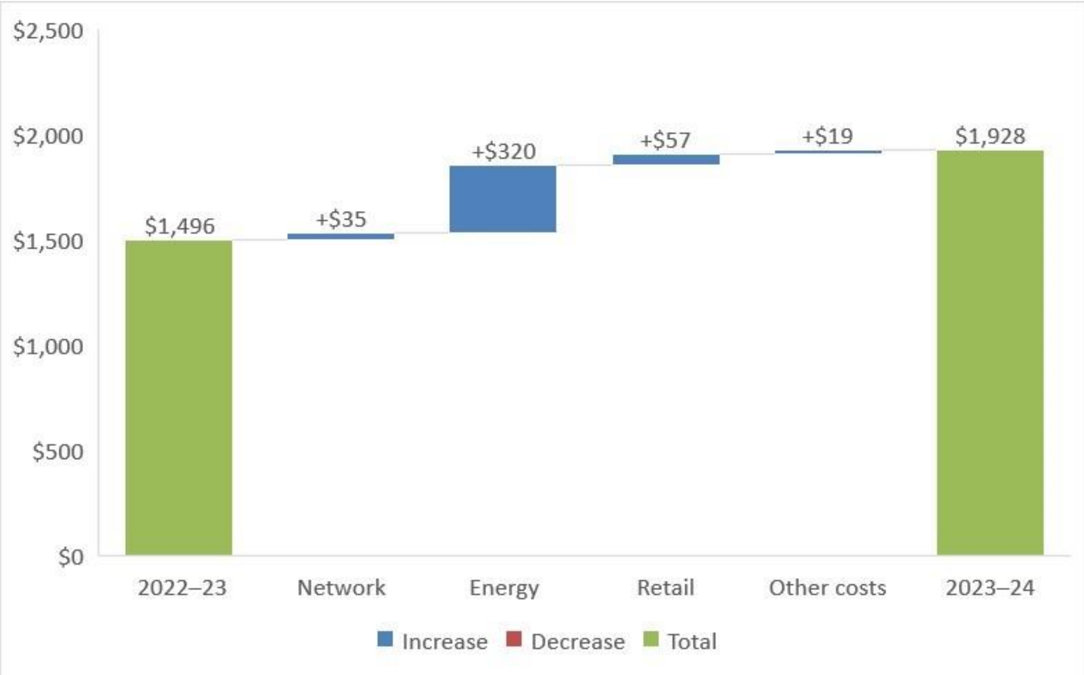
Relevantly, our wholesale energy cost estimates also take into account the potential impacts of the recent intervention (i.e. the temporary price caps for gas and coal) by the Australian and Queensland governments in December 2022.[17]

Other costs that have contributed to increases in draft notified prices include:

- higher retail costs, which incorporate metering service costs for small customers (this is a new matter for this year's determination and is discussed in section 3.2.2)
- higher network costs for most customer groups based on draft network prices provided by Energy Queensland (see section 4.1).

Figure 2.4 sets out the individual cost components contributing to the overall increase for a typical customer on Tariff 11. It demonstrates that rising energy costs are a key contributor to the increase in notified prices this year, although increases in other costs contribute as well.

Figure 2.4 T11 bill comparison, 2022–23 and 2023–24 (incl. GST)—changes in cost components[18]



[17] See section 4.2.1, pp 23–25.

[18] Amounts are rounded to the closest dollar. Metering costs are included. Bills are based on the consumption of a typical customer with a median annual consumption.

3 OVERARCHING FRAMEWORK

This chapter provides our draft positions on overarching framework matters that affect the cost level, structure and availability of notified prices.

The Minister's delegations (and terms of reference) set out overarching framework matters that we must consider in our approach for setting notified prices. This year, the delegations include additional matters for us to consider, relevant to developing new retail tariffs and setting small customer metering costs, that support broader Queensland Government initiatives.

3.1 Approach for setting notified prices

The terms of the delegations require us to consider:

- the UTP, which 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
- using the network plus retail (N+R) cost build-up methodology to set notified prices, where the N component (network costs) is treated as a pass-through and the R component (energy and retail costs) is determined by us.

The terms of the delegations also require us to consider additional matters relevant to determining the R component for:

- the new retail tariffs, using a methodology that will create stronger price signals than existing time-of-use tariffs
- small customer tariffs, determining the retail costs of metering services (including for advanced digital meters (ADMs)) and incorporating these costs in notified prices.

The delegations are broadly consistent with those in previous years and the way we have set notified prices in past determinations. However, there are some new matters (see section 3.2 below).

Stakeholder submissions

Several stakeholders said the cost of electricity continues to be a primary concern in regional Queensland, with equitable pricing and affordability among the key issues raised.[19]

Analysis and draft position

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

As discussed in section 1.2, our approach to setting notified prices is framed by the relevant legislative factors set out in the Electricity Act and the matters in the delegations. In particular, the delegations include the requirement for us to consider the Queensland Government's UTP,

[19] Cotton Australia, sub. 1, p 1; BRIG, sub. 2, p 1; PVW, sub. 4, p 1; QFF, sub. 6, p 3.

which is the policy mechanism available to help deliver more affordable electricity prices to regional Queensland.

This year, we will continue to set notified prices having regard to the UTP—that is, by basing notified prices:

- for small customers—on the cost of supplying small customers in south east Queensland (SEQ)
- for large customers—on the costs of supplying large customers in the Ergon Distribution area with the lowest cost of supply that is connected to the NEM (i.e. east zone, transmission region one).

This approach is consistent with previous price determinations and benefits most customers who would otherwise pay higher electricity prices due to the higher cost of supplying electricity in regional Queensland.[20] The UTP relies on the Queensland Government subsidising electricity prices for regional customers by funding the difference between the cost of supply and the prices paid by customers through the community service obligation (CSO) subsidy (expected to be around $568 million in 2022–23).[21]

We will also continue setting notified prices using the N+R methodology, by:

- applying the network prices and tariff structures to be approved by the Australian Energy Regulator (AER) (i.e. passing through the N component)
- adding our estimate of energy and retail costs (i.e. the R component, determined by us).

When estimating energy costs, we have taken into account the potential impacts of the Australian Government's Energy Price Relief Plan (in particular, the price caps placed on gas and coal),[22] which was introduced to address higher energy costs and the associated increase in electricity prices (see section 4.2.1).[23]

Further information on the individual cost components and our approach to setting these is provided in chapter 4.

We acknowledge that the draft notified prices represent a considerable increase to a typical customer's electricity bill (see chapter 2) and that customers may continue to have affordability concerns despite the mechanisms available to us (and which we have employed) in setting notified prices.

However, the legislative framework requires us to take a cost-based approach to setting notified prices—this means we must reflect the higher costs of electricity supply in our determination. We do not consider it our role to apply measures beyond those already provided through the delegations to further lower prices for customers in regional Queensland.

Further actions to address affordability concerns are best achieved through more direct measures, which ensure those in need (who are eligible) can access additional support. Such measures include concessions and rebates, broader income support arrangements, consumer

[20] Compared to SEQ, electricity needs to be transported over longer distances and to a lower density customer base.
[21] Queensland Government, *Budget Strategy and Outlook 2022–23*, Budget Paper 2, June 2022, p 202.
[22] Temporary price caps were placed on gas and coal, which are key inputs for thermal generators.
[23] Australian Government, *Energy price relief plan*, media release, Prime Minister of Australia website, 9 December 2022, accessed 23 January 2023.

protection frameworks and customer hardship programs. The Energy Price Relief Plan also includes targeted bill assistance measures.[24]

Box 1 sets out key support measures currently available to electricity customers. We encourage customers facing hardship to contact their retailer to discuss support measures that may be available to them. Beyond this, customers could also explore options to reduce energy costs, including by managing how energy is used (i.e. whether improvements to energy efficiency could reduce electricity bills) and comparing tariff options (e.g. savings may also be experienced by switching to a tariff structure that better suits a customer's electricity consumption patterns.[25] We have included resources providing information on how to improve energy efficiency and different tariffs options in Box 1. We recommend customers contact their retailer to explore what tariffs options are best suited to them.

[24] Australian Government, *Energy price relief plan*, media release, Prime Minister of Australia website, 9 December 2022, accessed 23 January 2023.

[25] For example, customers who use electricity during non-peak daytime periods might consider whether the two new retail tariffs are appropriate for them (see section 3.2.1).

Box 1 Support for electricity customers in regional Queensland

Hardship policies

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

Ergon Energy Retail's (EER) Customer Assist program is available to eligible customers who are experiencing financial hardship, helping with payment of electricity bills, including via payment plans.

Government schemes, concessions and other programs and resources

Eligible Queensland pensioners and seniors can access electricity rebates.

The Home Energy Emergency Assistance Scheme provides one-off emergency assistance for households experiencing problems paying their electricity bills as a result of an unforeseen emergency or a short-term financial crisis that has occurred within the past 12 months.

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 ecoBiz program helps small to medium businesses develop an action plan to cut energy costs, providing benchmarking assistance to help track resource use and on-site coaching sessions to help identify opportunities to implement initiatives to cut energy costs.

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 on energy concessions and support for businesses can be found on the Queensland Government's website. Other resources for stakeholders include:

- Queensland Farmers' Federation (QFF) website provides information and resources on electricity prices, understanding your bill, government schemes and concessions, and specific information for different industries, including specific programs available for customers.
- EER's website provides a range of information to assist customers, including households, businesses and farming customers.
- The Australian Government's energy.gov.au website provides advice for households and businesses on how to manage bills and improve energy efficiency, as well as setting out the rebates and assistance available in different jurisdictions, including Queensland
- The Energy made easy website allows customers to compare tariff options, having regard to current energy consumption patterns and other relevant details.

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 Additional matters

The terms of the delegations include additional matters this year, which relate to Queensland Government initiatives aimed at facilitating and accelerating the transition to renewable energy (including the uptake of electric vehicles (EVs)) and targeting 100 per cent penetration of ADMs by 2030.[26,27]

3.2.1 New retail tariffs

We have been delegated the task of developing two new retail tariffs that build on the existing small customer time-of-use (TOU) tariffs 12B and 22B (the 'solar-soaker' tariffs), namely:

- a residential 3-rate TOU energy tariff
- a small business 3-rate TOU energy tariff.

The terms of the delegation provide for the N component of the new retail tariffs to be set using the approach we apply for the existing TOU tariffs 12B and 22B. However, the delegation includes specific pricing considerations for setting the R component of the new retail tariffs. In particular, we have been asked to develop a methodology to provide greater price differentials between peak and non-peak periods (compared to the existing TOU tariffs 12B and 22B).[28]

The Minister said these tariffs would mean suitable options are in place for EV customers to make the most of charging options during the day (when network utilisation is low and solar PV generation is high), supporting the use of more renewable energy, consistent with the Queensland Government's initiatives.[29]

The development of these new retail tariffs was initially canvassed and generally supported by stakeholders as part of last year's notified prices review.

Stakeholder submissions

In general, stakeholders were supportive of us developing new retail tariffs aimed at providing sharper price signals to customers.[30] However, stakeholders raised a range of matters for us to consider:

- Stakeholders said the new tariffs should be made available beyond EV and battery storage customers.[31] The Bundaberg Regional Irrigators Group (BRIG) said we should consider allowing large irrigation customers operating in the 100–160 MWh bracket access to the new retail tariff.[32]
- BRIG suggested price levels for the new small business retail tariff and said the peak period for the TOU tariffs should be reduced from five to three hours.[33]

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[26] The Queensland Energy and Jobs Plan outlines how Queensland's energy system will transform to deliver clean, reliable and affordable power for generations. For more information, see Queensland Government, *Queensland Energy and Jobs Plan*, Department of Energy and Public Works website, n.d., accessed 31 January 2023. Similarly, the AEMC recently recommended a target of a universal uptake of smart meters by 2030 in the NEM (AEMC, *Review of the regulatory framework for metering services,* draft report, November 2022, pp ii, 19).
[27] Queensland Government, *Queensland's new Zero Emission Vehicle Strategy*, Queensland Government website, updated 20 September 2022, accessed 31 January 2023.
[28] Appendix A: Minister's delegation for the new retail tariffs, terms of reference, cl. 2(b).
[29] Appendix A: Minister's covering letter.
[30] Ergon Energy Network and Energex, sub. 3, p 1; BRIG, sub. 2, p 2; EER, sub. 5, p 10.
[31] Cotton Australia, sub. 1, p 1; BRIG, sub. 2, p 2; EER, sub. 5, p 10.
[32] BRIG, sub. 2, p 2.
[33] BRIG, sub. 2, p 2.

- The Pioneer Valley Water Co-operative Limited (PVW) said the new tariffs did not take into account agricultural irrigation projects, where it is optimal to operate at night.[34]
- QFF said the new tariffs must be cost-reflective to encourage EV users to charge at optimal times. More broadly, QFF said costs to upgrade the network for EVs must not be spread across the network, and users should be consulted on the impacts EVs could have on the NEM.[35]
- EER said instead of introducing the new retail tariffs in addition to the existing tariffs 12B and 22B, we should make these obsolete (with a 24-month phase-out date) or alternatively repurpose the existing tariffs.[36] EER said this was appropriate, given the large suite of regulated retail tariffs and the minimal impact it would have on customers. On our approach to setting the R component, EER recommended we apply a weighted calculation using both digital meter and net system load profile (NSLP) data. EER said the majority of its digital metered customers were on flat-rate tariffs, meaning their load shapes may not reflect the load profile of a customer on a TOU tariff. Further, it said the relatively small number of customers on tariffs 12B and 22B would not enable us to build wholesale energy costs for the new tariffs.[37]

Analysis and draft position

Our draft position is to set the two new retail tariffs (to be identified as tariffs 12C and 22C in the draft gazette notice) by:

- setting the N component by applying the network prices used to set the existing TOU tariffs 12B and 22B (i.e. applying the relevant network prices for the Energex distribution area but utilising Ergon Distribution tariff structures)
- setting the R component by:
  - estimating time-varying energy costs, whereby existing wholesale energy cost estimates are used as a base and are allocated to different time periods on a set of weightings aligned with the distribution of spot price variations throughout the day
  - establishing retail costs using the same approach taken to set existing TOU tariffs 12B and 22B (i.e. adjusting last year's fixed retail costs for inflation and maintaining last year's variable retail cost allocators).

As the Minister said, the intent of the two new retail tariffs is to provide stronger price signals than the existing TOU tariffs, which could encourage customers to use electricity during daytime periods, when network utilisation is typically low.[38] This could limit the potential need for network upgrades and associated costs that are of concern to QFF.

The terms and conditions for the new retail tariffs will be consistent with those of the existing TOU tariffs 12B and 22B. This means the new retail tariffs will not be restricted to EV and battery

[34] PVW, sub. 4, p 1.
[35] QFF, sub. 6, pp 4–5.
[36] Repurposing the existing TOU tariffs would mean tariffs 12B and 22B become the new retail tariffs, with energy costs calculated according to our new methodology described above. Customers would no longer be able to access existing TOU tariffs calculated according to our usual approach, and there would be no phase-out period. In effect, tariffs 12B and 22B would be replaced with the new retail tariffs.
[37] EER, sub. 5, p 11.
[38] Given the intent of these tariffs is to encourage electricity use during the day, these tariffs may not be well suited to those irrigation customers who prefer to operate at night. We encourage customers to contact Ergon Retail and explore what retail tariff options are available to them.

storage customers. While the tariffs aim to encourage a more sustainable uptake of EVs, the tariffs will be available to residential and small business customers with smart meters who can access existing tariffs 12B and 22B respectively.[39]

Setting the new retail tariffs in the manner described above is consistent with our broader pricing approach (see section 3.1) and the specific considerations related to setting the R component for the two new retail tariffs.

Capping prices and establishing retail tariff structures (including peak periods) that are different from the corresponding network tariffs would not be consistent with the delegation, including the requirements to consider the N+R methodology and the UTP. Similarly, with respect to QFF's view that EV customers should face cost-reflective prices, we note that while this is a factor we consider under the Electricity Act, we must also consider the UTP.

While setting energy costs in the manner described above is a departure from our usual approach, and does not reflect how retailers are likely to incur their costs, our approach is based on our existing wholesale energy cost estimates and is consistent with policy guidance from the Minister. It also reflects the evolving market conditions, with the accelerated roll-out of ADMs giving customers the ability to manage their energy use and consumption patterns more efficiently.[40] Time-varying wholesale energy costs are likely to be more appropriate as the penetration of ADMs increases.

We provide further detail on our approach to setting the individual N and R components in chapter 4.

While the Minister's covering letter indicates that the new retail tariffs will be additional to the existing TOU tariffs 12B and 22B,[41] we acknowledge EER's view that the existing tariffs should be phased out, given the number of regulated retail tariffs already available. EER considered that the customer impacts from making the existing tariffs obsolete (with a 24-month phase-out date) or repurposing the tariffs would be minimal.

As we noted in our review of the retail tariff schedule as part of our 2022–23 determination, 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.[42] However, while the new retail tariffs will be similar in structure to the existing TOU tariffs 12B and 22B, there are greater price differentials for the peak and off-peak periods, which will affect customers differently.

We seek to better understand the impact on customers if the existing TOU tariffs were to be phased out. Where there is limited impact on customers, it may be appropriate to phase out the tariffs.

While it is our understanding that the existing TOU tariffs have a relatively low uptake[43], we seek to understand whether customers have made investments, or otherwise structured their

[39] This means the new retail tariffs will not be available to irrigation customers operating in the 100–160 MWh bracket. Consumption thresholds that define small and large customers are established in legislation and are not something we can change. As such, these concerns go beyond the scope of our review. We explain how we are constrained in considering such matters in section 5.4.

[40] We discussed emerging issues and pricing options in the context of EVs in our previous determination (QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, final determination, May 2022, pp 22–29).

[41] Appendix A: Minister's covering letter.

[42] QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, final determination, May 2022, p 15.

[43] Based on information provided by Energy Queensland, we understand there were less than 50 national meter identifiers (NMIs) and 150 NMIs assigned to tariffs 12B and 22B respectively at 25 April 2022.

business or household, to take advantage of these tariffs and what the impact would be if customers had to switch to the new retail tariffs. On this, we seek stakeholder views on whether the 24-month phase-out date EER proposed is appropriate or whether it would be appropriate to repurpose these tariffs with no phase-out date.

3.2.2 Metering costs

The Minister's delegation requires us to consider:

- setting retail metering service costs as part of the R component for small customer tariffs, based on:
  - metering costs for standard type 6 meters in the Energex distribution area (SEQ)
  - costs incurred by retailers for small customer ADM services in the Energex distribution area
  - the rate of replacement of distributor meters with ADMs
- setting a retail charge for customers who have voluntarily disabled the remote communication function of their ADM (known as a 'type 4A meter'), such that the charge is based on EER's average costs of manually reading a type 4A meter.

The Minister's covering letter noted that enabling retailers to recover costs associated with the provision of all metering services is important in the context of the Queensland Government's broader energy plans, which target 100 per cent penetration of ADMs by 2030.[44] The Minister also said it is important to ensure similar customers do not pay different amounts simply based on the type of meter they have (consistent with the UTP).[45]

Stakeholder submissions

EER supported setting metering costs in accordance with the delegation and recommended we apply a similar methodology to the one the AER uses when including ADM costs in the default market offer (DMO) (i.e. it includes the recovery of digital meter costs plus legacy accumulation capital charges that retailers continue to incur when such a meter is removed). EER also said the Gazette should be amended, so that EER can recover metering provider costs from customers.[46]

EER said it is difficult to determine average costs of manually reading a type 4A meter, as costs depend on customers' geographic location, access to their meter, and the availability of meter reading staff.[47] As a short-term measure, EER suggested aligning the retail charge to the special meter read fee contained in Schedule 8 of the Electricity Regulation 2006 (Electricity Regulation).[48]

QFF said further consultation is required, given we have been asked to set (metering) costs that contribute to notified prices, including on how we set the manual meter read fee and what it will mean for customers' energy bills.[49]

[44] Queensland Government, *Queensland Energy and Jobs Plan: Power for generations—70% Renewable Energy by 2032*, September 2022, p 36.
[45] Appendix A: Minister's covering letter, p 2.
[46] EER, sub. 5, pp 10–11.
[47] EER, sub. 5, p 10.
[48] EER, sub. 5, p 10.
[49] QFF, sub. 6, p 3.

Analysis and draft position

Our draft position on metering costs, including the approach we have applied to estimate metering costs, is outlined in table 3.1.

The metering costs for small customer primary and secondary tariffs will be captured in the daily supply charge for each tariff, as the delegation requires these metering costs to be included in the R component of the notified prices. A separate metering charge for small customers will not be included in the tariff schedule this year. We have made consequential amendments to the tariff schedule set out in the draft gazette notice (Appendix F) to reflect this approach for small customers.

Table 3.1 Draft position on metering costs for small customer tariffs, 2023–24 (excl. GST)

Description	Metering costs	Approach
Primary tariff	17.59 c/day	To incorporate metering costs in the R component, we used: • draft type 6 meter costs for 2023–24 provided by Energy Queensland (EQ) • the AER's ADM costs used to set the DMO for the Energex distribution area in 2022–23.[50] We then calculated a weighted cost based on replacement rates of distributor meters with ADMs for regional Queensland for 2023–24 provided by EQ.
Secondary tariff	3.37 c/day	To incorporate metering costs in the R component, we used the relevant draft type 6 meter costs that EQ provided. We did not include ADM costs, as customers with a secondary tariff will already pay for the ADM component through their primary tariff.
Type 4A manual meter read fee	$37.62 per meter read	We based the type 4A manual meter read fee on the AER-approved special meter read fee.

Source: AER, Default market offer prices 2022–23, final determination, May 2022, pp 67–68; information provided by EQ; QCA analysis.

Retail metering service costs for small customer tariffs

We consider our approach to setting metering costs for small customer tariffs appropriate, based on the requirements of the delegation and the information available.

Consistent with the delegation, our approach means customers will contribute to the costs of type 6 and ADM meters, regardless of which type of meter they have.[51] The relevant costs are also based on costs in the Energex distribution area, rather than the Ergon distribution area, aligning with the UTP.

Our approach reflects the Queensland Government's plans for 100 per cent penetration of ADMs by 2030, as it will allow retailers to recover costs associated with all metering services (including ADMs, which has not been the case in previous years).

The draft metering costs reflect actual cost data for the Energex distribution area, consistent with the delegation. This data includes the ADM costs that the AER used to set the DMO for 2022–

[50] In order to derive a cost for small customers, we combined the costs for residential and small business customers by weighting the respective ADM costs by residential and small business numbers.

[51] Customers with type 6 meters will now pay a contribution to ADM costs, same as customers with an ADM, whose charges were previously based on the cost of type 6 meters in SEQ.

23,[52] which it obtained from retailers in SEQ. As the AER's ADM costs were collected at 30 September 2021, we have made adjustments to account for inflation.[53]

We intend to update cost data in our final determination, pending the availability and timing of this information.

Retail charge for manually reading a type 4A meter

We consider it appropriate to set the fee for manually reading a type 4A meter based on the costs to conduct a special meter read, having considered the information available to us and advice from EER.

While the delegation asked us to set the fee based on the average costs EER incurs when manually reading a type 4A meter, EER has informed us that this information is not readily available.[54] We understand that the costs to manually read meters may vary from customer to customer depending on geographic location, meter accessibility, availability of meter reading staff and other factors.[55]

We are of the view that a special meter read represents a similar activity to manually reading a type 4A meter. While schedule 8 of the Electricity Regulation prescribes a maximum charge for a special meter read, the AER also approves a special meter read fee for Ergon Energy Network.[56] We understand that Ergon Energy Network applies the AER's special meter read fee at present.[57]

As such, we are of the view that the AER-approved special meter read fee provides a reasonable benchmark for setting the type 4A manual meter read fee. In establishing the type 4A manual meter read fee for our final determination, we intend to consider alternative benchmarks based on available information from EER and/or stakeholder submissions.

According to EER, only very few customers have disabled the remote communication function of their ADM.[58] This suggests the type 4A manual meter read fee will apply to only a small number of customers. Customers can avoid this fee if they do not voluntarily disable the remote communication function of their ADM.

[52] The ADM costs are a weighted per-customer price, based on the proportion of ADM customers. These costs have been adjusted to reflect the legacy accumulation capital charges that retailers continue to incur when an accumulation meter has been installed due to the request of the customer or a faulty accumulation meter, or when a smart meter has been installed by the retailer as part of the new meter deployment.

[53] We have applied the AER's approach to adjust for inflation. The AER updated the ADM costs to June 2023 for its 2022–23 DMO determination. We further updated those costs to June 2024 for our 2023–24 draft determination using the consumer price index (CPI) forecast of the Reserve Bank of Australia (RBA) for June 2024 (RBA, *Statement on Monetary Policy*, Economic Outlook, February 2023).

[54] EER, sub. 5, p 10.

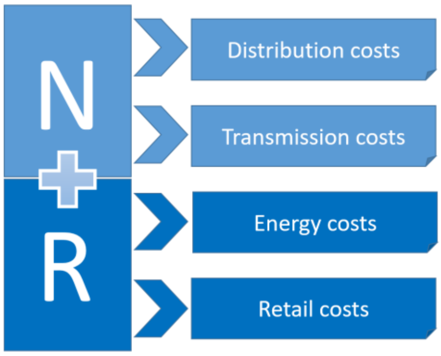
[55] EER, sub. 5, p 10.

[56] Approved special meter read fees are available for 2022–23, but not 2023–24. The AER approved the special meter read fee for 2022–23 in May 2022. AER, *Ergon Energy - Annual pricing 2022–23,* AER website, n.d., accessed 18 February 2023.

[57] Ergon Energy Network, *Network tariffs*, Ergon Energy Network website, n.d., accessed 18 February 2023 (in particular, see the 2022-23 Network Price List - Updated for ACS Sch8 Prices, available for download). The special meter read fee is currently set below the maximum charge prescribed by schedule 8 of the Electricity Regulation.

[58] EER, sub. 5, p 10.

4 INDIVIDUAL COST COMPONENTS



This chapter sets out our draft positions on matters related to the individual components that make up a retail tariff. Many of these matters are identified in the delegation, which we must consider when setting notified prices.

The individual components include:

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

4.1 Network component

The N component captures the costs of transporting electricity through transmission and distribution networks, as well as jurisdictional scheme charges.[59] These costs are regulated by the AER and reflected in the network prices it approves.

The delegations require us to consider setting the N component in a manner that reflects the overarching framework matters—that is, the UTP and N+R methodology (see section 3.1). We are required to consider setting the N component:

- for small customers on:
  - flat and secondary load control tariffs—based on the relevant Energex network prices (being the charges and tariff structures levied by Energex in SEQ)
  - tariffs 62A, 65A and 66A (limited access obsolete tariffs)—based on the relevant network prices for Ergon Distribution's east zone, transmission region one[60]
  - all other existing retail tariffs—based on the price level of the relevant Energex network prices but utilising Ergon Distribution tariff structures
  - for the new retail tariffs—based on the network prices used to set the existing retail tariffs 12B and 22B (for residential and small business retail tariffs respectively)
- for large customer retail tariffs—based on the relevant network prices for Ergon Distribution's east zone, transmission region one.[61]

The delegations are broadly consistent with those we received in previous years and the way we have set the N component of notified prices in previous determinations. However, there are some additional considerations relating to the new retail tariffs.

[59] In Queensland, these charges generally include the Solar Bonus Scheme (SBS) and AEMC levy costs.
[60] This is the Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM.
[61] Appendix A: Minister's delegation, terms of reference, cl. 2(c).

Stakeholder submissions

EER supported our approach to setting the N component, in light of the UTP.[62]

BRIG sought transparency around jurisdictional scheme charges (in particular, Solar Bonus Scheme (SBS) charges) included in electricity prices and said these should be removed from network costs and paid for by the Queensland Government (not electricity users).[63]

Analysis and draft position

We have set the N component for:

- existing small and large customer retail tariffs—by passing through the relevant network prices to be approved by the AER. Consistent with the UTP, this means:
  - for small customers on standard retail tariffs, basing the costs on the costs of supply in SEQ (Energex distribution area)
  - for large customers, and small customers on the limited access obsolete tariffs, basing the costs of supply on east zone, transmission region one (Ergon Distribution's lowest cost region that is connected to the NEM).
- new small customer retail tariffs—by passing through the relevant network prices to be approved by the AER, consistent with those used to set the existing retail tariffs 12B and 22B (i.e. basing costs on the costs of supply in SEQ (Energex distribution area)).

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 well as the specific considerations for the two new retail tariffs (discussed in section 3.2.1).

We are mindful that some customers would prefer the SBS charges not to be included in notified prices and would like these charges itemised in the notified price build-up. Similar concerns were raised by stakeholders in past price determinations. However, it remains the case that jurisdictional scheme charges (including SBS charges) are included in the AER–approved network prices, which form the basis of the N component in notified prices.

SBS charges reflect legitimate costs that EQ is entitled to recover through its network prices under the National Electricity Law. As jurisdictional scheme charges are included in the total AER-approved network prices, it is not necessary for us to separately include (or itemise) these for the purpose of setting the N component for notified prices.

Timing

We have used draft network prices Ergon Energy Network and Energex provided to us. We intend to use the AER-approved network prices in our final determination, pending the availability and timing of this information.

If the AER has not published the approved network prices by the time we make our final determination, we propose to use the 2023–24 network prices submitted to the AER by Ergon Energy Network and Energex. If the AER-approved prices differ from those submitted by Ergon Energy Network and Energex, we will consider using a cost pass-through mechanism to adjust for material differences in the future.[64]

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[62] EER, sub. 5, p 4.
[63] BRIG, sub. 2, pp 2–3.
[64] If we are delegated this task.

Network costs included in draft notified prices

Overall, network costs have increased for small and large customers this year. Figures 4.1 and 4.2 show the network costs included in draft notified prices—compared to last year's estimates—by tariff type, for typical small and large customers.

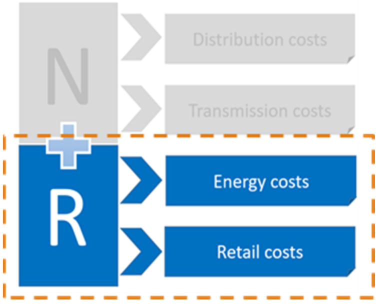
Figure 4.1 Draft network costs—typical customers on small customer tariffs (incl. GST)

Notes: Amounts are rounded. Percentage changes are based on unrounded amounts.

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

Notes: Amounts are rounded. Percentage changes are based on unrounded amounts.

4.2 Retail component



The R component consists of energy costs and retail costs, including metering related costs. It captures the costs that retailers incur when they purchase electricity from the NEM to supply their customers, run their general operations (including a return for the risks that retailers face when operating in the market) and provide metering related services.

Unlike previous years, the delegation requires us to consider incorporating the costs of metering services (for small customers) as part of the R component.

The terms of the delegation do not specify how we are to determine the R component, except in relation to metering costs. We have set the R component for notified prices in accordance with these requirements (see sections 4.2.1 and 4.2.2).

4.2.1 Energy costs

Energy costs are a key cost component of notified prices and include the costs associated with wholesale energy costs, other energy costs (including the Renewable Energy Target) and energy losses.

We engaged ACIL to provide expert advice and inform our review and energy cost estimates.[65] As with our previous reviews, all information we relied on in ACIL's report is available on our website.

Stakeholder submissions

EER observed that market conditions have changed dramatically since our last review and said we need to enhance the forecasting method to better reflect the increased spread of risks faced by retailers in two areas:

- spot prices—ACIL's forecasts must include the impact of stress events in the market, including by using the latest market data on movements in fuel costs and generator availability and including the impacts of the government intervention (i.e. price caps for coal and gas) in December 2022
- contract prices—while contract prices eased following the government intervention, ACIL's forecasts need to recognise retailers build their hedge positions over a two-to-three-year period in line with their financial risk management policies. Therefore, their contracts were purchased at higher prices well ahead of the government intervention (between May and December 2022).[66]

EER provided in-principle support for using ADM demand profiles to inform our wholesale energy cost estimates but said we should consider the potential impacts and, if necessary, apply a combination of approaches with a glide path to soften any unexpected price impacts for retailers and customers.[67]

When estimating other energy costs, EER supported:

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65 ACIL Allen, *Estimated Energy Costs*, draft report, prepared for the QCA, February 2023.
66 EER also highlighted the increasing incidence of negative spot prices within the NEM and the illiquidity of cap products in the market (EER, sub. 5, pp 3–8.). These matters are addressed in Appendix B.
67 EER, sub. 5, p 8.

- using a forward-looking approach to estimate NEM fees, as it provides a more reasonable basis for estimating a retailer's expected costs for the coming year
- including costs associated with market events during 2022, namely for:
  - activation of the Reliability and Emergency Reserve Trader (RERT) in June and July 2022
  - retailers' costs to date relating to the administered pricing event (in June 2022), noting that the AEMC is still considering compensation claims and suggested a true-up could be applied in 2024–25 to account for any under- or over-recovery.[68]

Wholesale energy costs

Wholesale energy costs relate to the costs retailers incur for purchasing electricity from the NEM. Retailers adopt a range of strategies to reduce their exposure to volatile and rapidly changing wholesale electricity prices (spot price risk), including pursuing hedging (financial), contractual and operational strategies.

The specific considerations for setting the wholesale energy costs for the two new retail tariffs (including to create sharper price signals) are discussed in a separate section below.

Analysis and draft position

Our draft position is to estimate wholesale energy costs based on ACIL's advice, which uses a market hedging approach (designed to simulate the NEM from a retailer's perspective) and up-to-date market data.

A core feature of this approach is that it incorporates a hedging strategy that a prudent retailer would adopt to manage spot price risk in the NEM. More specifically, this involves:

- simulating a broad range of expected spot prices that a retailer may face, considering demand profiles, generation costs, power station availability and competitive dynamics
- estimating wholesale energy costs for a retailer that hedges spot price risk through the purchase of ASX Energy contracts.

We consider this approach is transparent and likely to produce robust wholesale energy cost estimates that closely reflect prevailing conditions in the NEM and relevant financial markets:

- it uses the latest available information (up to 20 January 2023) on:
  - the uptake of rooftop solar PV, renewable energy traces[69], AEMO's latest peak demand and supply projections, and market participants' formal announcements on generation availability/operation[70]
  - publicly available information on the cost of purchasing electricity in the NEM (via ASX financial contracts).
- it addresses stakeholder concerns (discussed below and in Appendix B).

[68] EER, sub. 5, pp 8–9.

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

[70] This includes the medium-term projected assessment of system adequacy (MT–PASA) published by AEMO. AEMO employs the MT–PASA process to determine if there is sufficient capacity expected to be available to meet forecast demand over the medium term (a 2-to 3-year time horizon). Market participants submit their expected plant availability for the next 36 months and are required to update their PASA submission on an ongoing basis to ensure it matches their current intentions and best estimates.

As such, we consider this approach is appropriate—it takes account of, among other things, the likely variations in demand profiles and generation supply/costs within the NEM, while still meeting our draft determination timeframe.

Compared to last year, our estimate of the wholesale energy costs increases substantially for all customers in 2023–24. For small customer tariffs, the increase is between 24.7 and 66.4 per cent, and for large customer tariffs, the increase is around 40.3 per cent.[71]

This primarily reflects a substantial increase in the trade-weighted ASX contract prices for base and cap contracts—which is driven by market participants expecting higher spot prices and greater price volatility, likely due to:

- higher gas and coal prices—thermal generators have been facing higher fuel costs due to the war in Ukraine and energy sanctions imposed on Russia (a major global oil, gas and thermal coal producer). These developments have added further uncertainty to energy markets already impacted by global supply constraints[72] (due to the covid-19 pandemic), which led to high and volatile gas and coal prices[73]
- uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland NEM region:
  - Kogan Creek began a scheduled outage in September 2022 for a major overhaul, but its return to service was delayed for more than a month due to additional repairs[74]
  - Callide C (unit 3) has experienced a forced outage since October 2022. The operator (CS Energy) initially advised the unit was expected to return to service in February 2023, but has recently delayed this from June to September 2023. CS Energy also delayed the return of service of Callide C (unit 4) from May to October 2023.[75]
  - These outages reduced the average available capacity by around 864MW in Q4 2022.[76]

These market conditions directly impact the costs retailers incur when purchasing electricity in the NEM.

Key cost drivers and impacts of government intervention

As previously discussed, the increase in wholesale energy costs reflects the substantial increase in the trade-weighted ASX contract prices. Notably, since the war in Ukraine in late February 2022, ASX base contract prices for Queensland (Q1 2024) increased markedly, reaching a record high of

[71] Also see Table 4.2 of ACIL's report, which sets out the wholesale energy cost estimates by customer group.

[72] Ng, J, 'Commodities soar as war builds anxiety over supply shortages', *Bloomberg*, 4 March 2022, accessed 31 January 2023.

[73] Domestic prices of coal and gas are influenced by international prices because some producers may have the option of exporting these resources and receiving international prices. As such, thermal power stations compete with international buyers and this affects the fuel costs of these generators.

[74] CS Energy, *Kogan Creek power station overhaul extended*, news release, 12 October 2022, CS Energy website, accessed 31 January 2023.

[75] Callide C (unit 4) has been unavailable since May 2021 following a major explosion (CS Energy, *Updated return to service date for Callide C units*, news release, 23 December 2022, CS Energy website, accessed 31 January 2023). CS Energy, *Updated return to service date for Callide C units*, news release, 8 March 2023, CS Energy website, accessed 9 March 2023. We note the effects of the most recent update and extension of return to service dates is not captured in our draft determination (as we used market data up to 20 January 2023). However, it will be reflected in the final determination (by using market data up to late April / early May 2023).

[76] For Q4 2022 AEMO reported an average output of 4,616MW for black coal in Queensland. See AEMO, *Quarterly Energy Dynamics Q4 2022*, January 2023, p 20–21.

around $243/MWh (Figure 4.3). This reflects market participants' expectations of both higher future spot prices and greater price volatility relating to these events.

In December 2022, the Australian Government partnered with the states and territories to introduce an Energy Price Relief Plan with measures to address high energy costs. As part of this policy, temporary price caps of $12/GJ for gas and $125/tonne for coal were implemented.

Market participants’ views of the potential impacts of these price caps is best illustrated in Figure 4.3, which shows the movement of ASX base contracts for the summer quarter for 2023–24 (Q1 2024). Since the government intervention, contract prices have been lower, fluctuating between $113/MWh and $137/MWh.

Our approach captures the potential impacts of these price caps through the use of traded contract prices and spot price analysis. To calculate the trade-weighted ASX prices for 2023–24, we used contract prices and trade volumes for Queensland since they were first traded in March 2020 until 20 January 2023 (inclusive). Therefore, our approach captures the higher prices of ASX contracts that retailers acquired from May to December 2022, before the government intervention, consistent with EER's views.

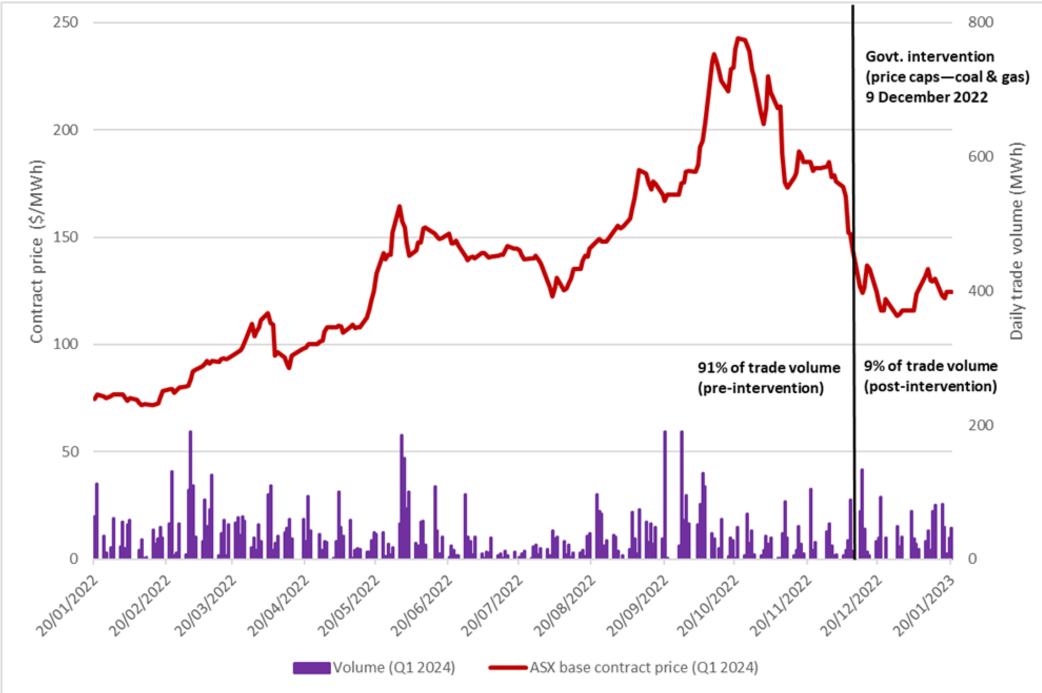
To take into account the impacts of the government intervention, we assumed that the price caps apply to all relevant fuel supply contracts throughout the 2023–24 financial year. This implementation reflects a simplified approach, as there are potential exemptions and a mandatory code of conduct for domestic gas producers pending.[77] However, we consider this approach is reasonable, based on current government policies and other information available at this time. Further, conditions related to this intervention still exist, as international gas and coal export prices remain elevated and volatile. We will monitor this matter closely and incorporate any relevant developments regarding this intervention in our spot price modelling for the final determination.

As previously indicated, the announcement of the government intervention coincided with a decline in, and stabilisation of, contract prices. However, as retailers purchase energy in advance to manage the risk of spot price volatility, they effectively lock in a price and their electricity requirements. For our estimates of notified prices for 2023–24, retailers had already locked in most of their costs before the government intervention.

This dynamic can be illustrated by observing the movement in trade volume for the ASX base contracts (Q1 2024), where around 91 per cent of contracts were locked in prior to the implementation of the price caps in December 2022. Therefore, only 9 per cent of these contracts were affected by the price caps for the purpose of our analysis.

[77] Australian Government, *Options to ensure the domestic wholesale gas market delivers for Australians*, The Treasury website, accessed 31 January 2023.

Figure 4.3 Queensland ASX base contract for 2023–24 (Q1 2024)



Source: ASX Energy and QCA analysis.

For our final determination, we will use ASX data until late April/early May 2023 to estimate contract prices.

Refinements

We made two methodology refinements to incorporate:

- ADM data, used to inform the forecast consumption profiles
- additional data, to more accurately estimate ASX contract prices.

Integration of ADM data

To date, we have not used demand profiles of ADMs to inform our wholesale energy cost estimates, due to the low penetration of ADMs. Also, further work was needed to obtain relevant information from AEMO and ensure it was appropriate (and robust) to use.[78]

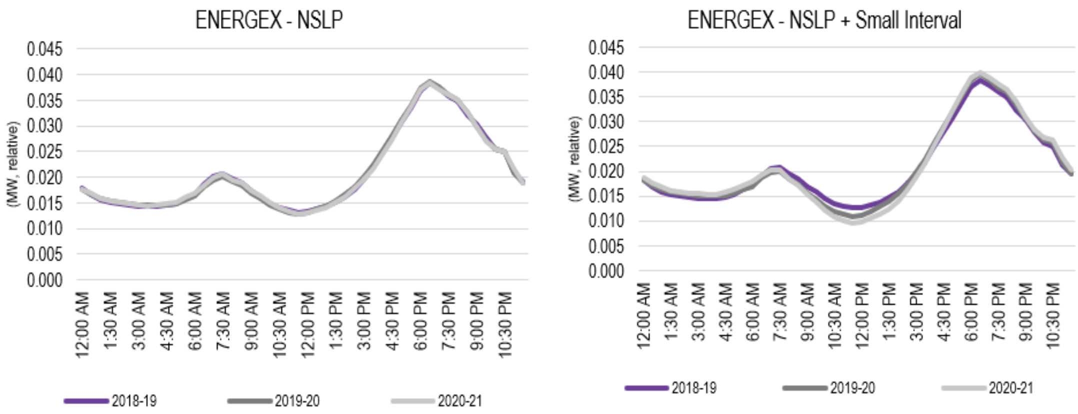
This year, we decided to incorporate ADM data, in combination with the relevant net system load profiles (NSLPs) and controlled load profiles (CLPs), to estimate wholesale energy costs.[79] Sufficient information has been obtained from AEMO, which our analysis indicates is reasonable to be used. In particular, the ADM profile for small customers is 'peakier' than the NSLP[80] and shows a reduction in daytime demand due to increased rooftop solar PV penetration over time, as we would expect (see Figure 4.4).

[78] For example, see QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, draft determination, February 2022, p 21.

[79] The NSLPs and CLPs are published by AEMO and are used to approximate the demand of customers on accumulation meters.

[80] On the other hand, for large customers the ADM profile is flatter than the NSLP as large customers consume a greater proportion of their energy during the daytime.

Figure 4.4 Energex NSLP with ADM data



Source: ACIL Allen analysis of AEMO data - Figure 2.3 in ACIL's report

We consider this approach is appropriate, given the penetration of ADMs will continue to increase in Queensland.[81] Also, including ADM data now will ensure our estimates reflect the organic change in market information over time.[82] We also understand it reflects what retailers do in practice when developing their hedging strategies (i.e. retailers do not distinguish between customers with different meter types, but rather combine the profiles of ADMs and accumulation meters (for a specific customer group)).

ASX contract prices

When we estimate ASX contract prices, we also consider the cost retailers face to manage risk through call options.

Our existing approach to estimating ASX contract prices incorporates call options (for base contracts) uses a simplified approach, where options are approximated using the volume of options traded and ASX daily settlement prices for base contracts.

Given the recent market volatility, ACIL incorporated additional data on:

- strike prices of call options exercised
- premiums of call options exercised and expired
- trade volume of call options exercised and expired.

Including this additional data accounts for:

- call options (not put options)[83]—based on advice from ACIL. Subject to stakeholder comments, we consider this reasonable as unlike put options, call options allow retailers the opportunity to purchase more base contracts, in order to manage their spot price risk

[81] In this context, the Queensland Government's policy initiative is targeting 100 per cent penetration of ADMs by 2030. This issue is discussed in section 3.3.2 (Queensland Government, *Queensland Energy and Jobs Plan: Power for generations—70% Renewable Energy by 2032*, September 2022, p 36). Further, the Power of Choice reforms implemented rule changes to facilitate deployment of ADMs across the NEM, including that all new and replacement meters for small customers be ADMs from 1 December 2017.

[82] It also reduces the potential risk of a 'step change' in prices if the ADM data is included all at once, when ADM penetration is higher. This risk is particularly relevant if the aggregate load profile of customers on ADMs is different to that of customers on the NSLP.

[83] In this context, put options are a type of financial derivative that gives the holder the right, but not the obligation, to sell ASX base contracts at a predetermined price (i.e. strike price) and volume.

- premiums of call options both exercised and expired, as retailers pay a premium to the seller of options, regardless of whether they choose to exercise the option.

We consider this approach better reflects the actual costs retailers incur in practice, by incorporating actual data on individual trades of contracts and base options.[84] We particularly seek comments from stakeholders on this refinement, which is a new matter to this review.

Time-varying wholesale energy costs

We have been asked to develop a methodology for setting the wholesale energy costs for the new time-of-use tariffs to provide greater price differentials between peak and non-peak periods (compared to the existing time-of-use tariffs 12B and 22B on which the new retail tariffs will be based). This is intended to incentivise customers to use more electricity during non-peak periods (i.e. during daytime hours when network utilisation is low and solar PV generation is high).[85]

The methodology we developed to set the energy costs for the new retail tariffs involves:

- using the wholesale energy cost estimates for existing small customer tariffs 12B and 22B
- deriving a set of weightings for different time periods based on the distribution of demand-weighted spot price variations throughout the day, which are typically lower during non-peak periods (i.e. daytime hours) compared to peak periods (i.e. evening hours)
- applying these weightings to the wholesale energy cost estimates (described above) to set rates that are lower during non-peak periods and higher during peak periods.

This approach maintains the same level of wholesale energy costs (as tariffs 12B and 22B) but changes the way these costs are recovered throughout the day to encourage consumption in a specific manner.

This approach is also likely to provide stronger price signals than existing time-of-use tariffs and, as the Minister noted, could incentivise customers to take up electric vehicle charging during non-peak periods.

Table 4.1 sets out the draft tariff components for the new tariffs, based on the methodology described above.

Table 4.1 Time-varying wholesale energy costs for new time-of-use retail tariffs

Retail tariff	Period	c/kWh
Tariffs 12C and 22C (residential and small business time-of-use tariffs)	Peak (evening)	29.331
	Non-peak (day)	3.601
	Shoulder (night)	9.577

Note: For tariff 12C, peak usage is 4 pm to 9 pm; non-peak (day) usage is 9 am to 4 pm; shoulder (night) usage is all other times. For tariff 22C, peak usage is 4 pm to 9 pm weekdays; non-peak (day) usage is 9 am to 4 pm; and shoulder (night) usage is all other times.

Other energy costs and losses

Retailers incur other energy costs when purchasing electricity from the NEM, namely:

[84] See p 44 of ACIL's report.
[85] See section 2.3.1.

- Renewable Energy Target (RET) costs—costs associated with the purchase of certificates to meet the targets mandated under the RET. The RET consists of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES)[86]
- NEM management fees and ancillary services charges—the costs levied by AEMO to cover the costs of operating the NEM and to manage power system safety, security and reliability
- Reliability and Emergency Reserve Trader (RERT) scheme charges—charges levied by AEMO to cover the costs of maintaining power system reliability and security using reserve contracts. The RERT scheme allows AEMO to contract for emergency reserves, such as generation or demand response outside of the NEM
- prudential capital costs—the costs a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX for futures contracts.

Retailers also incur costs associated with:

- energy losses, as retailers purchase more electricity than customer demand to allow for the losses that occur when electricity is transported across the network
- significant market events that occur from time to time, such as the triggering of the administered price cap and suspension of the wholesale market by AEMO (from 12 to 24 June 2022). It would be appropriate to incorporate any additional costs retailers incurred due to these events.

Analysis and draft position

Our draft position is to estimate other energy costs based on ACIL's advice[87], specifically:

[86] LRET and SRES, provides incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions. The costs of these incentives are paid by retailers through the purchase of large-scale generation certificates (LGCs) and small-scale technology certificates (STCs). LGCs or STCs can be created when eligible electricity is generated by utility-scale renewable generators or small-scale renewable systems.

[87] See section 2.3.3 of ACIL's report.

RET costs	**Large-scale Renewable Energy Target (LRET) costs** These costs were 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 These costs were 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	These management fees were estimated based on the latest data from AEMO, including historical costs and projected changes in costs.
Ancillary services	These charges were estimated using the average historical costs observed over the preceding 52 weeks.
Prudential costs	These costs were estimated using AEMO's prudential requirements and margin requirements for trading in the ASX futures market.
RERT scheme charges	These charges were estimated using the historical costs published by AEMO for the preceding 52 weeks (excluding costs incurred in June 2022, see June 2022 events).
Energy losses	These losses have been estimated by applying transmission and distribution loss factors published by AEMO, in a manner that aligns with AEMO's settlement process.
June 2022 events	Costs associated with market events in June 2022 were estimated using the latest data from the AEMC and AEMO. These include the RERT costs and compensation costs published by the AEMC and AEMO to date.

We consider ACIL's estimates are appropriate and produce reliable estimates of the other energy costs likely to be incurred by retailers, including by using the latest relevant market data and information. In particular, ACIL uses relevant AEMO data (to estimate other energy costs, except for RET costs) and information published by the Clean Energy Regulator (to estimate the RET costs).[88]

The estimates are forward-looking and, consistent with EER's views, include the costs associated with the RERT and market events in June 2022. As the AEMC has not finalised estimates of the costs associated with market events, we have included the costs approved to date and intend to update this if further information becomes available.

Similarly, we have included energy losses based on AEMO's 2022–23 published loss factors. We intend to update this using AEMO's 2023–24 loss factors if this information is available for the final determination.

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

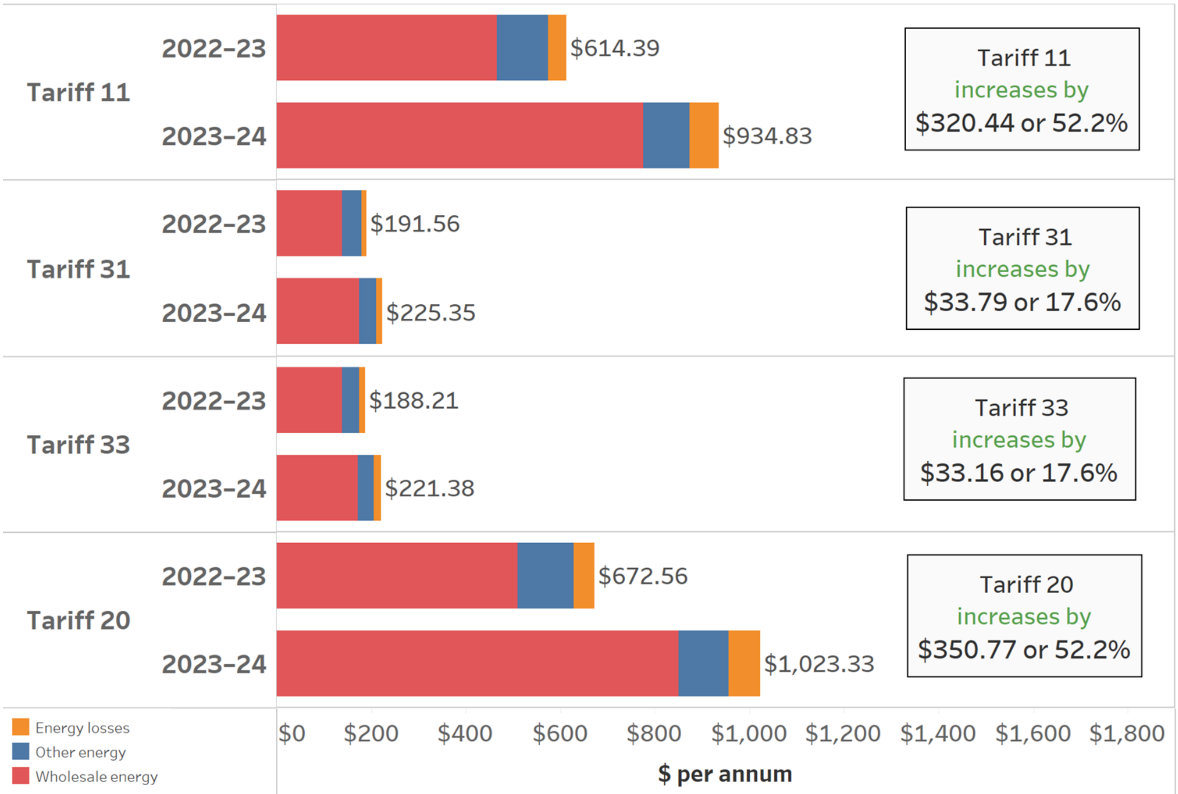
- 9.4 per cent ($2.07/MWh) lower for small customer tariffs
- 13.3 per cent ($2.86/MWh) lower for large customer tariffs.

Total energy costs included in draft notified prices

Overall, energy costs are estimated to increase for all customer groups, compared to last year's estimates. Figures 4.5 and 4.6 show the overall energy costs included in draft notified prices—compared to last year's estimates—by tariff type, for typical small and large customers.

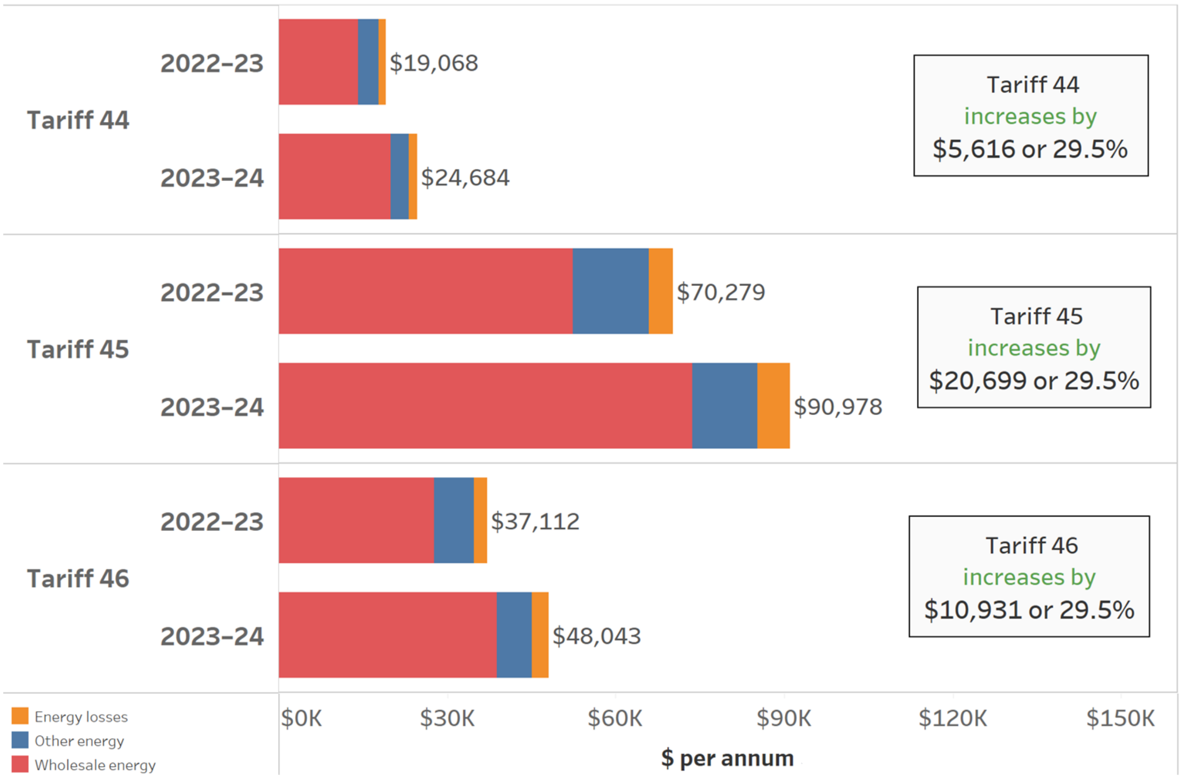
[88] See section 2.3.3 to 2.3.5 of ACIL's report.

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



Note: Amounts are rounded. Percentage changes are based on unrounded amounts.

Figure 4.6 Draft energy costs—typical customers on large customer tariffs (incl. GST)



Note: Amounts are rounded. Percentage changes are based on unrounded amounts.

4.2.2 Retail costs

The costs of running a retail electricity business include:

- operating costs—the administrative costs of servicing existing customers and acquiring new customers (e.g. costs related to operating call centres, operating billing systems and collecting revenue)
- a retail margin—the return to investors for a retailer's exposure to systematic risk associated with providing retail electricity services.

The delegations are broadly consistent with those in previous years, and require us to determine the R component, without specifying a particular approach or methodology for setting the retail cost allowance. However, retail costs include metering costs for small customer tariffs this year (discussed in section 3.2.2).

In past determinations, we estimated retail costs by using established benchmark allowances, which we adjusted for inflation.[89] We undertook a fulsome review of retail costs as part of the 2021–22 notified prices review.[90] As a result:

- for residential and small business customers—we established new retail costs (including fixed costs and cost allocators used to set the variable component of the retail cost allowances) to reflect up-to-date market information
- for large customers—we maintained existing retail costs (including the fixed costs and cost allocators used to set the variable component of the retail cost allowances),[91] as there was insufficient evidence to vary the allowance for this customer class.

Stakeholder submissions

EER said we should incorporate costs associated with regulatory reform, resource challenges and heightened trading risks into retail cost allowances. In particular, the reforms progressing in the NEM (driven by the Energy Security Board's NEM 2025 program) reflect a step change in costs driving system and resource investment, as demonstrated by AEMO's identification of this work program as a declared project. EER said it is also facing increasing compliance costs with rule changes such as the AEMC's Family Violence rule change.[92]

Analysis and draft position

Our draft position is to maintain the approach we used last year and set retail cost allowances by:

- adjusting last year's fixed retail costs[93] (for residential, small business and large customers) for inflation[94] to maintain the fixed retail costs in real terms

[89] The benchmark retail cost allowances were first established in 2016–17.
[90] For more information, see Appendix C and ACIL's reports from our *2021–22 determination*.
[91] Except to adjust fixed costs for inflation.
[92] EER, sub. 5, p 9.
[93] These fixed retail costs reflect those set as part of 2021–22 review, adjusted for inflation (i.e. the residential and small business costs that were established as part of the 2021–22 review and the large customer costs that were established in 2016–17 and reviewed as part of the 2021–22 review).
[94] We applied the RBA's CPI forecast of 3.5% for 2023–24. See RBA, *Statement on Monetary Policy*, Economic Outlook, February 2023.

- maintaining the variable retail cost allocators at:[95]
  - 7.25 per cent for residential customers
  - 18.7 per cent for small business customers
  - 6.0445 per cent for large customers.

This approach has also been applied to set retail costs for the two new retail tariffs.

We have considered EER's comments, but do not consider it appropriate to adjust retail costs at this stage, as it is not clear there will be a material incremental increase in retail costs for 2023–24 compared to 2022–23.[96] Should evidence be provided, we will consider this in our final determination.

More broadly, we recognise there are a number of changes occurring across the NEM (including the reforms EER identified associated with the Energy Security Board's NEM 2025 program).[97] As these reforms progress, we acknowledge they may result in additional costs for retailers.[98]

Given retail costs were last subject to an in-depth review in 2021–22, we consider there may be merit in undertaking another review of retail costs in the near future. This will allow us to consider not only potential costs associated with reforms and compliance, but also any savings to retail costs that may have occurred (for example, through productivity improvements).

Retail costs included in draft notified prices

Overall, retail costs have increased for small and large customers this year. Figures 4.7 and 4.8 show the retail costs included in draft notified prices—compared to last year's estimates—by tariff type for typical small and large customers.

The retail costs for small customer tariffs include the cost of metering services set out in section 3.2.2.

[95] These variable cost allocators were set as part of 2021–22 review (i.e. the residential and small business allocators that were established as part of the 2021–22 review and the large customer allocator that was established in 2016–17 and reviewed as part of the 2021–22 review).

[96] AEMO's identification of the Energy Security Board's NEM 2025 program as a declared project does not identify the scale of costs that retailers may incur, nor demonstrate an incremental increase to retail costs overall.

[97] We understand that while some reforms have already been implemented or are due for implementation shortly, a degree of uncertainty remains around the implementation and timing of others.

[98] Including for retailers in SEQ who we consider when setting retail costs, consistent with the UTP.

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

Notes: Includes small customer metering costs to facilitate a like-for-like comparison. Amounts are rounded. Percentage changes are based on unrounded amounts.

Figure 4.8 Draft retail costs—typical customers on large customer tariffs (incl. GST)

Notes: Amounts are rounded. Percentage changes are based on unrounded amounts.

5 OTHER COSTS AND PRICING MATTERS

This chapter sets out our draft views on other costs and pricing matters, including adjustments we need to consider when setting notified prices this year. The matters we discuss are:

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

5.1 Standing offer adjustment—small customers

The Minister has asked us to consider the costs and benefits associated with standing offers in SEQ as well as the AER's DMO for SEQ, given the Queensland Government's UTP.[99]

Consistent with past determinations, when setting notified prices for small customers, we intend to consider:

- incorporating a standing offer adjustment (SOA) in notified prices for small customers, intended to reflect the value of more favourable terms and conditions in standard contracts relative to market contracts
- comparing the notified price bill (including a SOA) to the equivalent DMO reference bill in SEQ and consider reducing the value of the SOA if the notified price bill exceeds the equivalent DMO reference bill (the DMO comparison).[100]

Stakeholder submissions

Stakeholders did not comment on the value of the SOA. However, QFF said we should outline the methodology for adjusting the DMO (in the event this is required) and identify and detail how the DMO adjustments are calculated in the final determination.[101]

Analysis and draft position

Our draft position is to:

- incorporate a SOA of 4.56 per cent into small customer notified prices
- not undertake the DMO comparison (or adjust the value of the SOA) until the final determination, because the AER had not published its draft DMO prices for SEQ by the time we finalised our draft determination.

SOA value

We adopted the same approach as last year to determine the SOA, taking into account more recent market data.

[99] Appendix A: Minister's delegation, covering letter.
[100] Provided the value of the SOA is not reduced below zero.
[101] QFF, sub. 6, p 3.

Using 2021–22 SEQ market data,[102] we:

- assessed the range of fees and charges attached to retail market contracts
- identified any additional fees in market contracts compared with standard contracts
- determined the potential fees that small customers in SEQ on market contracts could incur annually (that would not be incurred on a standard contract).

Consistent with last year, we consider these fees serve as an appropriate proxy for the value of the SOA, as they represent additional costs attached to market contracts that small customers on standard contracts avoid.

Based on our assessment, small customers on market contracts in SEQ could incur, on average, around $59 in additional fees (on top of their annual bill). This equates to around 4.56 per cent of a small customer's annual electricity bill and supports the view that the terms and conditions attached to standard contracts still provide some value to small customers. Customers avoid fees and charges when they are on a standard contract. In addition, retailers cannot change the terms (and prices) for standard contract customers as they can with market contract customers, which provides more certainty and predictability to standard contract customers.

This year's SOA is higher than the 3.7 per cent SOA incorporated into notified prices last year (the difference is $7, or 0.86 per cent points).[103]

DMO comparison

As the AER's 2023–24 draft DMO reference bill for SEQ was published contemporaneously with our draft determination, we have not undertaken the DMO comparison as part of this draft determination.[104] We will do this comparison in our final determination, using the AER's draft (or final) DMO reference bill for SEQ to assess whether the SOA should be reduced.

We intend to use the same method applied in previous determinations to undertake the DMO comparison. Detailed information on the method, including how we identify if any adjustments are required, is contained in past determinations and available on our website.[105] The method and result of the DMO comparison this year will be detailed in our final determination in a separate technical appendix (as we have done in previous determinations).

5.2 Cost pass-through mechanism

Cost pass-through mechanisms are generally used by regulators to manage 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 the draft notified prices this year.

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[102] This data reflects our most recent review of retail fees (QCA, *SEQ retail electricity market monitoring 2021–22*, December 2022, pp 60–65, 67–72).

[103] Factors contributing to this increase were that some retailers with lower fees attached to their market offers in our previous analysis did not have any plans published anymore, while some of the new retailers had comparatively higher fees attached to their market offers.

[104] AER, *Draft determination of the Default Market Offer for 2023–24*, news release, 27 January 2023.

[105] For more information on the methodology and approach applied, see QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, final determination, May 2022, technical appendix D; QCA, *Regulated retail electricity prices for 2021–22*, regional Queensland, technical appendices—final determination, June 2021, technical appendix F.

SRES cost pass-through

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

Generally, at the time of our final determination for notified prices, only the SRES liabilities for the first half of the financial year are known, while liabilities for the second half are based on the forecasts from the CER. The CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination. If there are discrepancies between the CER's forecast and its final determination of the SRES liabilities, it can lead to an over- or under-recovery of SRES costs.

Analysis and draft position

For the draft determination, we used the CER's SRES liabilities for 2023, as reflected in its most recent decision, which results in lower-than-expected SRES liabilities for 2023–24. This means retailers are required to purchase fewer certificates to surrender to the CER than initially forecast—leading to an over-recovery of SRES costs for 2022–23 and a decrease in usage charges for all retail tariffs for 2023–24.[106]

Our draft position is to incorporate the over-recovery of 2022–23 SRES costs in 2023–24 notified prices. We consider this to be appropriate, given that it aligns notified prices with the UTP-consistent costs of supply.

The pass-through provisions discussed here may, or may not, remain appropriate in the future, depending on the regulatory framework for future price determinations and whether changes are made to the UTP. Therefore, we cannot commit to the continued availability of a cost pass-through mechanism beyond this price determination.

5.3 Metering costs—large customers

We did not receive stakeholder submissions on large customer metering. We consider it is appropriate to maintain our current approach, under which we:

- separate the large customer metering costs for ADMs from retail costs and estimate these metering charges separately
- estimate metering charges based on confidential data provided by retailers, averaged to produce cost estimates for each large customer type.

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

5.4 Additional issues raised by stakeholders

Table 5.1 addresses other issues stakeholders raised that are not addressed elsewhere in this report.

Table 5.1 Additional issues raised in stakeholder submissions

Stakeholder submissions	Our response
Scope of review and consultation	We perform our role in accordance with the requirements of the Electricity Act and the terms of the Minister’s delegation(s). If stakeholders consider

[106] See Appendix C for further detail on how we estimated the SRES cost pass-through.

Stakeholder submissions	Our response
Cotton Australia raised concerns with what it considered to be a regimented approach to price setting and lack of willingness to provide public advice to the government on how tariffs and associated issues such as equal access can be improved.[107] QFF said our framework does not allow for meaningful consultation, including to consider the issues and solutions provided. As such, we should seek a direction to extend the scope of our review for further consultation with stakeholders, including on the metering costs to be set as part of this delegation.[108] QFF sought transparency around calculations and pre-emptive communication of proposed changes.[109]	the scope of our review (as set by the delegation) should be expanded to investigate or provide advice on particular policy issues, stakeholders should engage with the Queensland Government before a future notified prices review. 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. Our process includes the publication of an interim consultation paper and draft determination, providing transparency around our intended approach to setting notified prices and allowing stakeholders the opportunity to comment. We will consider stakeholder submissions on our draft determination and respond to those comments in our final determination. We will also hold information sessions on our draft determination.
Policy matters Stakeholders raised concerns in relation to a number of policy matters, including: • the N+R methodology—QFF said the pricing methodology is outdated and changes are required, which should be addressed as part of a separate delegation[110] • payment of the CSO—BRIG and QFF said this should be paid to Ergon Network[111] • customer consumption threshold levels—QFF said there should be an increase to the small customer threshold[112] • recovery of costs associated with the solar bonus scheme and RERT—BRIG said these should be met by a separate CSO, funded by the government[113] • supply of electricity—PVW said the co-gen unit at Mackay Sugar Racecourse Mill could be used to provide fixed rate electricity to cane growers in the Pioneer Valley.[114] Stakeholders said an affordable tariff would have a price ceiling of 16 c/kWh, based on network costs and retail costs each not exceeding 8 c/kWh.[115]	Stakeholders commented on a range of matters that go beyond the scope of our review. The scope of our review is set out in section 1.2 and is bound by the framework in which we operate and set notified prices. 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, or implement measures proposed by stakeholders aimed at addressing these concerns. These concerns arise in connection with the development and operation of the overarching framework (legislation and policy), rather than how a particular task is performed within this framework (our role in setting notified prices).
Pricing matters QFF requested that an investigation be undertaken on the potential for tariff 22B to become a solar	In section 3.2.1, we discuss the two new retail tariffs we developed, including one based on 22B for small business customers. In relation to QFF's comment regarding solar soaker tariffs, the delegation requires us to set a new retail tariff based on tariff

[107] Cotton Australia, sub. 1, p 1.
[108] QFF, sub. 6, p 3.
[109] QFF, sub. 6, p 5.
[110] QFF, sub. 6, p 5.
[111] BRIG, sub. 2, p 2; QFF, sub. 6, p 2.
[112] QFF, sub. 6, p 5.
[113] BRIG, sub. 2, pp 2–3.
[114] PVW, sub. 4, p 1.
[115] BRIG, sub. 2, p 1; PVW, sub. 4, p 1; QFF, sub. 6, p 2.

Stakeholder submissions	Our response
soaker tariff for small business customers and irrigators.[116]	22B. This new tariff will operate as a solar soaker tariff, available to small business customers.

Sources: Submissions on the consultation paper (ICP), published on the QCA website; QCA analysis.

[116] QFF, sub. 6, p 4.

6 DRAFT NOTIFIED PRICES

This chapter sets out the draft notified prices for 2023–24. A breakdown of the draft notified prices by cost component is provided in Appendix E. The draft gazette notice, which includes the draft notified prices published in a tariff schedule, and the eligibility criteria and terms and conditions for accessing each tariff, is provided in Appendix F.

Table 6.1 Draft notified prices—residential customers (excl. GST), 2023–24

Retail tariff	Fixed[a]	Usage			Demand
		Off-peak/ flat	Shoulder	Peak	
	c/day	c/kWh	c/kWh	c/kWh	$/kW/mth
Tariff 11—residential (flat-rate)	114.403	29.876			
Tariff 12B—residential time-of-use[b]	112.730	24.276	25.007	39.569	
Tariff 12C—residential time-of-use[b]	112.730	9.653	17.548	55.791	
Tariff 14A—residential time-of-use demand[c]	112.730	24.721			4.822
Tariff 14B—residential time-of-use demand[c]	112.730	23.893			8.976
Tariff 31—night rate (super economy)	3.519	17.666			
Tariff 33—controlled supply (economy)	3.519	19.397			

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.

Table 6.2 Draft notified prices—small business and unmetered supply customers (excl. GST), 2023–24

Retail tariff	Fixed[a]	Usage		Demand
		Off-peak/ flat	Peak	
	c/day	c/kWh	c/kWh	$/kW/mth
Tariff 20—business (flat-rate)	148.553	33.589		
Tariff 24A—business (time-of-use demand)[b]	146.671	29.582		5.169
Tariff 24B—business (time-of-use demand)[b]	146.671	28.475		11.575
Tariff 34—business (interruptible supply)	136.842	21.641		
Tariff 91—unmetered		30.432		

a Charged per metering point.

b Demand—4 pm to 9 pm on weekdays.

Table 6.3 Draft notified prices—small business customers (excl. GST), 2023–24

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]	146.671	177.516	208.465	239.520	270.470	26.747	31.749	45.744
Tariff 22C - small business time- of-use inclining band[b]	146.671	177.516	208.465	239.520	270.470	10.563	23.494	63.697

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

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

Table 6.4 Draft notified prices—large business and street lighting customers (excl. GST), 2023–24

Retail tariff	Fixed	Usage		Demand		Excess demand
		Off-peak/flat	Peak	Off-peak/flat[a]	Off-peak/flat[a]	
	c/day	c/kWh	c/kWh	$/kW/mth	$/kVA/mth	$/kVA/mth
Tariff 44—over 100 MWh small (demand)	4267.328	17.749		26.078	23.470	
Tariff 45—over 100 MWh medium (demand)	13675.783	17.749		26.078	23.470	
Tariff 46—over 100 MWh large (demand)	35585.297	17.749		20.769	18.896	
Tariff 50A—large business time-of-use demand [b]	17535.178	17.794			16.454	3.291
Tariff 60A—large business flat-rate interruptible supply (primary)	4267.328	21.698				
Tariff 60B—large business flat-rate interruptible supply (secondary)		21.698				
Tariff 71—street lighting		26.459				

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.

Table 6.5 Draft notified prices—very large business customers (excl. GST), 2023–24

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)	23433.369	14.058	7.329	3.603	3.867
Tariff 51B—high voltage (CAC 33 kV)	17144.569	14.058	7.329	4.376	4.006
Tariff 51C—high voltage (CAC 22/11 kV Bus)	16055.269	14.058	7.329	5.029	4.858
Tariff 51D—high voltage (CAC 22/11 kV Line)	15432.869	14.058	7.329	9.642	9.797
Tariff 53—high voltage (ICC)	23232.869	14.058		3.603	3.867
ICC site-specific—high voltage	2700.769	12.711		0.205	0.220

Table 6.6 Notified prices—very large business customers (excl. GST), 2023–24

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)	12865.169	15.757	13.724	7.329	6.434	15.049
Tariff 52B—high voltage (CAC STOUD 22/11 kV Bus)	12865.169	15.757	13.724	7.329	4.568	50.278
Tariff 52C—high voltage (CAC STOUD 22/11 kV Line)	12865.169	15.757	13.724	7.329	8.299	72.720

Table 6.7 Notified prices—large business customers (excl. GST), 2023–24

Retail tariff	Fixed	Usage[a]	
		Below threshold	Above threshold
	c/day	c/kWh	c/kWh
Tariff 43—Business customer (over 100 MWh)	4267.328	18.311	26.830

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—small business customers (excl. GST), 2023–24

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]	112.419	68.407	57.942	24.583		
Tariff 65A—time-of-use tariff[b]	112.119	54.524		30.304		
Tariff 66A—dual-rate demand tariff[c]	244.119			28.813	4.530	13.675

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

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

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

Table 6.9 Obsolete tariffs—large business customers (excl. GST), 2023–24

Retail tariff	Fixed	Usage		Demand	
		Off-peak/flat	Peak	Off-peak/flat	Peak[a]
	c/day	c/kWh	c/kWh	$/kW/mth	$/kVA/mth
Tariff 50—over 100 MWh seasonal time-of-use (demand)	3624.578	20.151	16.754	11.614	76.801

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

Table 6.10 Metering charges—large and very large business customers advanced meters (excl. GST), 2023–24

Customer type	Metering charge (c/day)
Standard asset customer (annual usage of 750 MWh or less)	216.940
Standard asset customer (annual usage greater than 750 MWh)	260.421
Connection asset customer	429.295
Individually calculated customer	375.281

Source: Retailer data.

GLOSSARY

ACIL	ACIL Allen
ADM	Advanced digital meter
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BRIG	Bundaberg Regional Irrigators Group
CER	Clean Energy Regulator
CLP	Control load profile
CPI	Consumer price index
Delegation(s)	The delegation(s) issued by the Minister for Energy, Renewables and Hydrogen (see Appendix A)
DMO	Default market offer
EER	Ergon Energy Retail
Electricity Act	Electricity Act 1994 (Qld)
Energex	Energex Distribution
EQ	Energy Queensland
Ergon Distribution	Ergon Energy Corporation Limited (electricity distribution arm)
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
ICE	Intercontinental Exchange
ICP	Interim consultation paper
ISP	Integrated System Plan
kVA	Kilovolt amperes
kW	Kilowatts
kWh	Kilowatt hour
LGC	Large-scale generation certificate
LOR 2	Lack of Reserve 2
LRET	Large-scale renewable energy target
MT–PASA	Medium-term projected assessment of system adequacy
MWh	Megawatt hour
N	Network costs
NEM	National Electricity Market

NER	National Electricity Rules
NERL	National Energy Retail Law
Notified prices	Regulated retail electricity prices
NSLP	Net system load profile
N+R	Network + retail cost build-up methodology
OTC	Over-the-counter
POE	Probability of exceedance
PPAs	Power purchase agreements
PV	Photovoltaic
PVW	Pioneer Valley Water Co-operative Limited
QCA	Queensland Competition Authority
QFF	Queensland Farmers' Federation
R	Energy and retail costs
RBA	Reserve Bank of Australia
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RRO	Retailer Reliability Obligation
SBS	Solar Bonus Scheme
SEQ	South east Queensland
SOA	Standing offer adjustment
SRES	Small-scale renewable energy scheme
STC	Small-scale technology certificate
STP	Small-scale technology percentage
TOU	Time-of-use
UTP	Uniform Tariff Policy
$/t	Dollars per tonne
$/GJ	Dollars per gigajoule

STAKEHOLDER SUBMISSIONS AND REFERENCES

Stakeholder submissions

We received six submissions on our interim consultation paper, which are available on our website.

Stakeholder	Submission number	Date received
Bundaberg Regional Irrigators Group (BRIG)	2	17 January 2023
Cotton Australia	1	11 January 2023
Ergon Energy Corporation Limited and Energex Limited (Ergon Energy Network and Energex)	3	18 January 2023
Ergon Energy Retail (EER)	5	19 January 2023
Pioneer Valley Water Co-operative Limited (PVW)	4	18 January 2023
Queensland Farmers' Federation (QFF)	6	19 January 2023

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