Queensland Competition Authority

Regulated retail electricity prices in regional Queensland for 2024–25

Draft determination

May 2024

Submissions

Closing date for submissions: 21 May 2024

Public involvement is an important element of our decision-making processes. Therefore, we invite submissions from interested parties. We will take account of all submissions received within the stated timeframes. Submissions, comments or inquiries regarding this paper should be directed to:

Queensland Competition Authority
GPO Box 2257, Brisbane Qld 4001
Tel 07 3222 0555
www.qca.org.au/submissions

Confidentiality

In the interests of transparency, and to promote informed consultation, we intend to make all submissions publicly available. However, if a person making a submission believes that information in it is confidential, they should claim confidentiality over the relevant information (and state the basis for that claim). We will assess confidentiality claims in accordance with the *Queensland Competition Authority Act 1997*. Among other things, we will assess if disclosure of the relevant information is likely to damage a person's commercial activities, and we will consider the public interest.

Claims for confidentiality should be clearly noted on the front page of a submission, and relevant sections of the submission marked as confidential. The submission should also be provided in both redacted and unredacted versions. In the redacted version, all information claimed as confidential should be removed or hidden. In the unredacted version, all information should be exposed and visible. These measures will make it easier for us to make the remainder of the document publicly available. A confidentiality claim template is available at **www.qca.org.au/submission-policy.**

The template gives guidance on the type of information that may help us to assess a confidentiality claim. We encourage stakeholders to use this template when making confidentiality claims.

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

Each year, we set regulated retail electricity prices for regional Queensland that reflect our estimate of the annual costs to a retailer of supplying electricity to customers.

In December 2023, the Minister for Energy and Clean Economy Jobs (the Minister) delegated us the task of setting regulated retail electricity prices (notified prices) for regional Queensland in 2024–25.[1] We received further correspondence from the Minister in March and April 2024[2] to delay publishing this draft determination and consider additional matters relevant to setting small customer notified prices (discussed below).

We undertake our review using a well-established framework based on factors in the Electricity Act and matters in the delegation (Box 1), stakeholder submissions[3], and our own analysis. This draft determination includes draft notified prices that are indicative only – and will be updated to reflect new information in the final determination.

Box 1: Overarching framework

When setting notified prices, the Electricity Act requires us to have regard to:

- 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.[4]

The Minister's delegation (and terms of reference) specifies policies, principles and other matters we must consider this year, such as:

- using the network plus retail (N+R) cost build-up methodology to set notified prices – this involves passing through network prices (approved by the AER) and adding retail and energy costs (which we determine)
- the Queensland Government's uniform tariff policy (UTP) – which provides that customers of the same class should pay no more for their electricity, and should pay via similar price structures, regardless of their geographic location. This means for most customers, prices are set below the actual cost of supply and are subsidised by the Queensland Government (via a community service obligation payment).

[1] The delegation was issued in accordance with s 90AA of the *Electricity Act 1994* (Qld).
[2] The March and April 2024 correspondence from the Minister is provided in Appendix A and published on our website.
[3] We received 5 submissions on the interim consultation paper, which are available on our website.
[4] Electricity Act, s 90(5)(a). We may also have regard to any other matter we consider relevant (Electricity Act, s 90(5)(b)).

Draft determination

In March 2024, the Minister asked us to delay publishing the draft determination and provided further matters for us to consider in April 2024 that resulted in reductions to small customer notified price bills to align with the AER's draft DMO reference bills for SEQ (see section 5.1).[5]

The draft notified prices in this report are presented as bundled prices, appropriate to the retail tariff structure (except for site-specific tariffs).[6] Further details and indicative customer bill impact charts are in chapter 2.

We have also considered new matters this year (metering costs and default tariff arrangements) that did not result in changes to our current approach (section 4.2 and 5.4).

Way forward

We are now midway through this year's notified prices review (Figure 1.1).

Figure 1.1: Stages of the review

We will hold online information sessions on key aspects of our draft determination.[7] This will occur soon after publishing the draft determination to assist stakeholders prepare submissions. In light of the changes to the timing of our draft determination, we are unable to hold information sessions in Brisbane or regional locations this year.

Stakeholders are also invited to comment on our draft determination via written submissions.[8] We will consider all stakeholder submissions received, along with other relevant information, when making our final determination.[9]

Submissions on the draft determination are due by 21 May 2024.

[5] The delegation and Ministerial correspondence is contained in Appendix A.
[6] As required in cl 8 of the schedule to the Minister's delegation (Appendix A1). 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.
[7] Further details on the information sessions are available on our website.
[8] For Information on making a submission, see our submission policy and online submission form.
[9] We encourage stakeholders to subscribe to our email alerts for the latest developments on this project.

1.1 Supporting information

A range of supporting information is available on our website. This includes:

- an information booklet, which provides an overview of the key issues for setting notified prices this year
- appendices to this report:
  - Appendix A: Minister's delegation and correspondence
  - Appendix B: SRES cost pass-through approach
  - Appendix C: Data used to estimate customer impacts
  - Appendix D: Build-up of draft notified prices
  - Appendix E: Draft gazette notice.
- a report on energy costs prepared by our consultant ACIL Allen (ACIL) to assist us in setting the energy cost component of notified prices (see section 4.2.1).

1.2 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 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.[10]

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

[10] Appendix A1: Minister's delegation, terms of reference, cl 2(a).

2 Indicative customer bill impacts

Overall, we forecast an increase in the underlying cost of supplying energy to most customers – which is reflected in the draft notified prices.

This is driven by changes to the costs that retailers face, though notified prices for small customers are capped to align with the equivalent AER draft DMO for SEQ. For all customers, energy costs have decreased, but there has also been a notable increase in network costs (determined by the AER). Further detail on changes to individual cost components and application of the AER's DMO reference bills as a cap is set out in chapters 4 and 5.

We present the impact to customer bills based on draft notified prices, relative to last year, below.

Importantly, the customer bill impacts are indicative only[11] and based on a set level of consumption – an individual customer's actual bill will vary due to the application of government rebates and concessions, in particular the $1000 cost of living rebate recently announced by the Queensland Government (discussed in chapter 3)[12], and how much electricity that customer uses.[13] Customers should engage with their retailer for further advice and information reflecting their individual circumstances.

2.1 Small customers

Based on the draft notified prices, and in the absence of the $1000 cost of living rebate announced by the Queensland Government, electricity bills for typical residential customers would increase by between 0.6% and 2.7% for customers on the main flat-rate tariff 11, depending on whether they are also on load control tariffs (Figure 2.1).

For typical residential customers, the overall increase is driven by an increase in network and retail costs (reflecting updated metering service costs) that is not fully offset by the decrease in energy costs (see Figure 2.3). As secondary load control tariffs 31 and 33 have decreased – driven by a substantial decrease in energy costs – the forecast increase is less.[14]

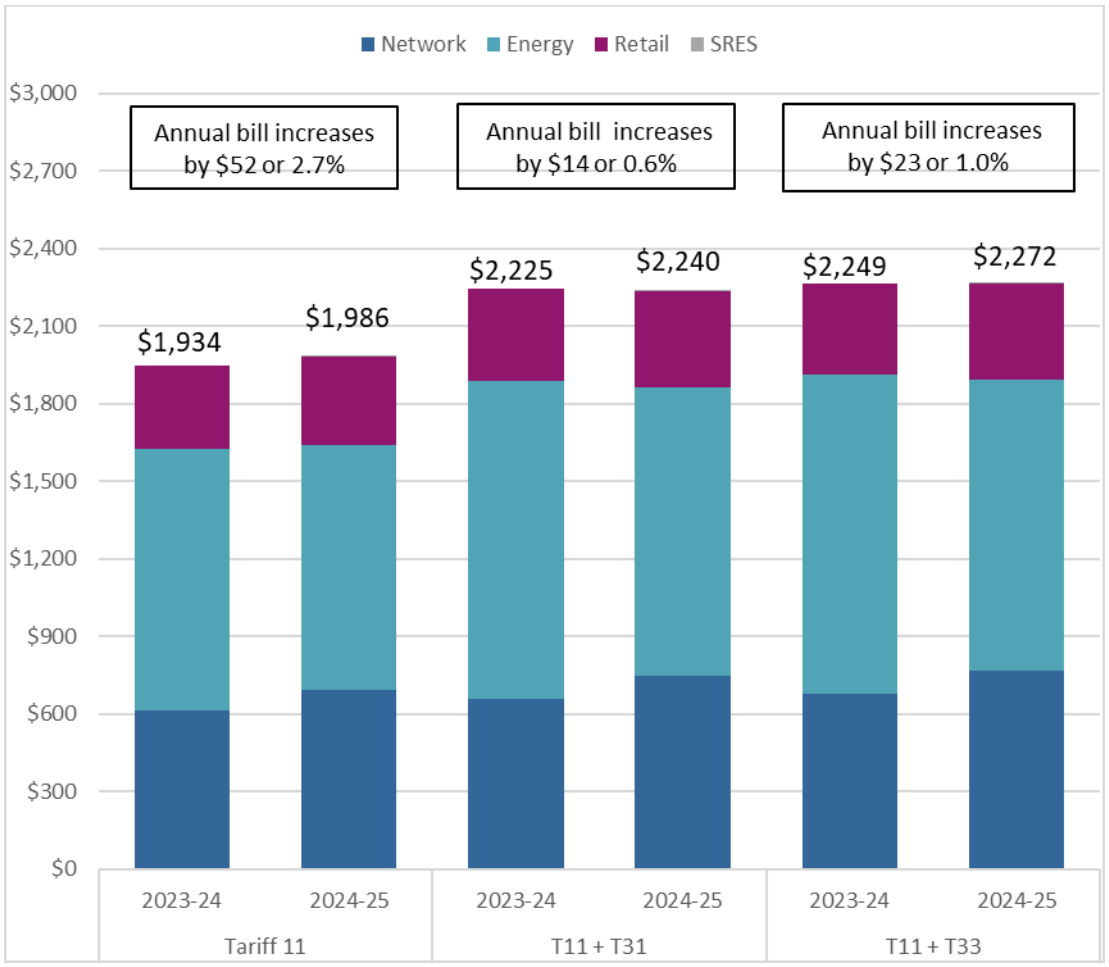
Importantly, in both cases, application of the AER's DMO as a cap has limited the forecast increase to annual electricity bills.

Based on the draft notified prices, electricity bills for typical small business customers on the main flat-rate tariff 20 would decrease by 3.2% (Figure 2.2).

[11] For the final determination updates to input costs may change the notified prices and bill impacts shown, including those highlighted in this report (e.g. draft network prices – see section 4.1) and the standing offer adjustment (section 5.1).
[12] Queensland Government, *Miles government delivers $1,000 for Queensland households*, Media Statement, 2 May 2024.
[13] The bills are calculated based on the consumption of a typical customer – that is, the median (middle) customer in terms of consumption among all customers in regional Queensland on the same tariff (Appendix C provides the consumption data used to estimate these bills).
[14] Secondary load control tariffs must be used in conjunction with primary tariffs (e.g. tariffs 11 or 20).

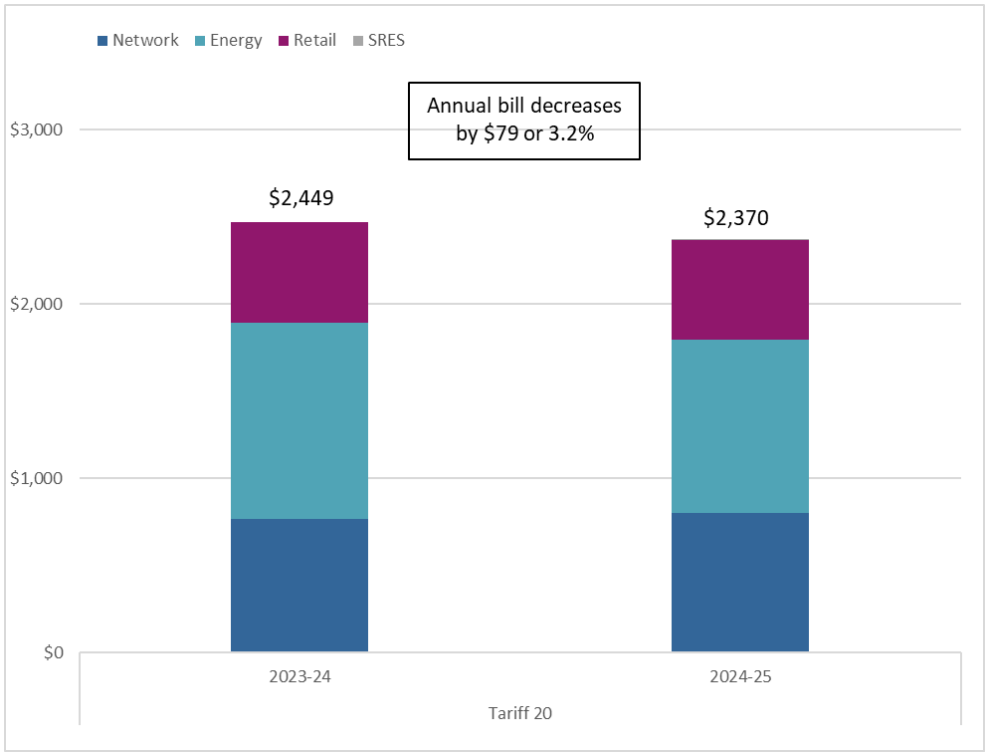
Similarly, for typical small business customers, there has also been an increase in network and retail costs, not fully offset by the decrease in energy costs. However, in this instance, application of the AER's DMO as a cap resulted in a forecast decrease in the annual electricity bill, relative to last year.

Figure 2.1: Residential customer bills, 2023–24 and 2024–25 (incl GST)



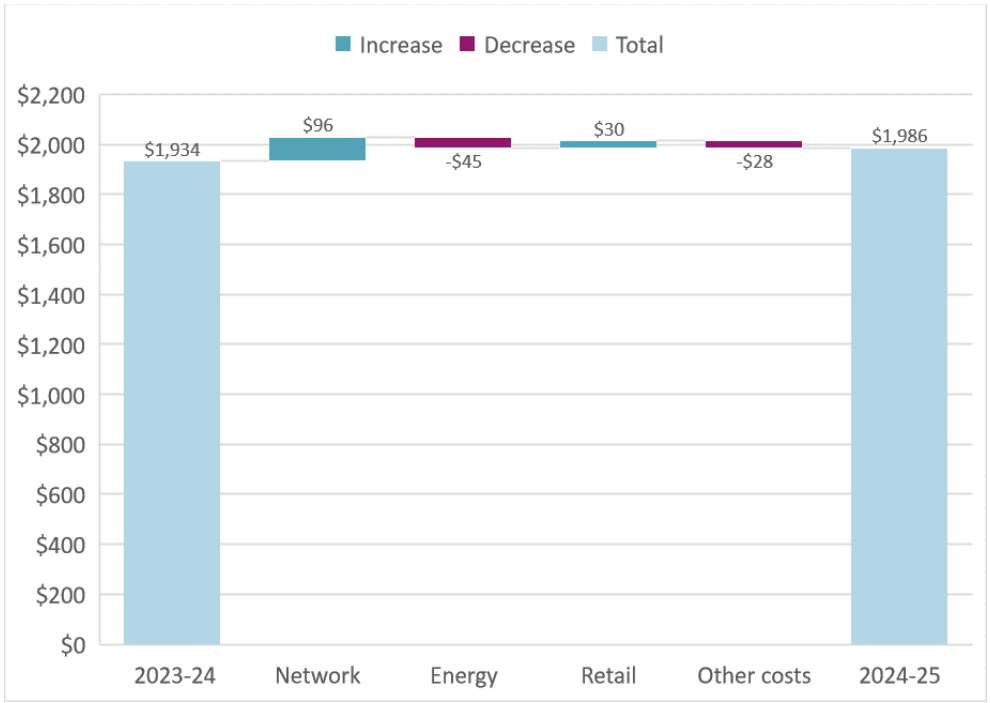
Note: SRES costs are also included in the figure above, however given the size of this component relative to the total bill, it is not apparent. Annual bills do not take into account the $1000 household cost of living rebate.

Figure 2.2: Small business customer bills, 2023–24 and 2024–25 (incl GST)



Note: SRES costs are also included in the figure above, however given the size of this component relative to the total bill, it is not apparent.

Figure 2.3: Tariff 11 bill – changes in cost components, 2023–24 and 2024–25 (incl GST)

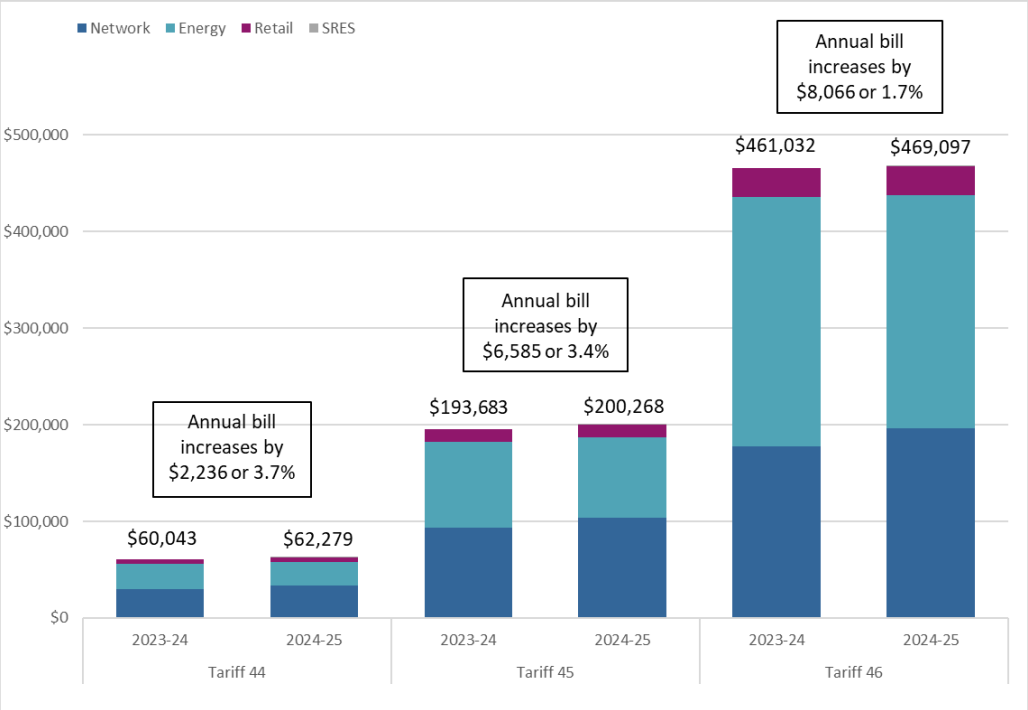


Note: Other costs include SRES and the standing offer adjustment. As the standing offer adjustment is negative this year (see section 5.1), overall other costs have decreased compared to last year. Annual bills do not take into account cost of living rebates.

2.2 Large customers

Based on notified prices, electricity bills for typical large customers would increase by between 1.7% and 3.7% (see Figure 2.4). This is driven by an increase in network costs, offsetting the decrease in energy costs.

Figure 2.4: Large business customer bills, 2023–24 and 2024–25 (incl GST)



Note: SRES costs are also included in the figure above, however given the size of this component relative to the total bill, it is not apparent.

3 Overarching framework

Our approach to setting notified prices considers the cost level, structure and availability of tariffs, having regard to the Queensland Government's UTP and the N+R cost build-up methodology.

The way we set notified prices is framed by relevant factors set out in the Electricity Act and the matters in the Minister's delegation (see chapter 1). In particular, the delegation requires us to consider:

- the Queensland Government's UTP – which provides that, wherever possible, customers of the same class should pay no more for their electricity, and should be able to pay for their electricity via similar common price structures, regardless of their geographic location
- using the N+R cost build-up methodology to set notified prices – where the N component (network costs) is generally treated as a pass-through and the R component (energy and retail costs) is determined by us.

Table 3.1 describes how we have regard to the UTP and the N+R cost-build up methodology when setting notified prices. This approach is consistent with the requirements of the delegation and is a long-standing practice for our price determinations.

Table 3.1: Overarching framework matters

Matter	Effect
Queensland Government's UTP	This means generally 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 Ergon Distribution's east zone, transmission region one (being the pricing region with the lowest cost of supply that is connected to the National Electricity Market (NEM)).
N+R cost build-up methodology	This means: • applying the network prices and tariff structures 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).

We are mindful of stakeholders' concerns around electricity prices and the affordability of electricity in regional Queensland. Some stakeholders have longstanding views that the pricing framework is outdated, and an affordable tariff would have a price ceiling of 16c/kWh.[15] However, the legislative framework requires us to take a cost-based approach to setting notified prices – this means we must reflect the costs of electricity supply in our determination.

[15] BRIG, sub 1, p 1; QFF, sub 5, p 4.

We are required to consider the Queensland Government's UTP, which is a policy mechanism that seeks to deliver more affordable electricity prices to customers in regional Queensland. It benefits most customers who would otherwise pay higher electricity prices due to the higher cost of supplying electricity in regional Queensland.[16] 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. This is done through a community service obligation (CSO) subsidy paid to Ergon Energy Retail by the Queensland Government (expected to be around $537 million in 2023–24).[17] We consider the application of the UTP in notified prices is consistent with the Minister's April 2024 correspondence that, when making pricing decisions and striking the right balance between customer outcomes and retailer needs, we should 'consider balancing the objectives toward consumer interests' where appropriate.[18]

While we acknowledge stakeholders' concerns and the changes recommended, including how the CSO should be paid,[19] the UTP is formulated and administered by the Queensland Government, and we have no ability to change it. However, we encourage stakeholders to raise these issues (and any others they may have with the UTP) directly with the Queensland Government.

We understand customers may continue to have affordability concerns despite the mechanisms available to us (and which we have employed) when setting notified prices. However, it is not our role, or within the scope of matters we can consider in our review, to apply measures beyond those already provided by the Queensland Government through the delegation to further reduce prices for customers in regional Queensland. Further actions to address affordability concerns are best achieved through more direct measures developed by government, which ensure those in need (as determined by government) can access additional support. Such measures include concessions and rebates, broader income support arrangements, consumer protection frameworks and customer hardship programs. Relevantly, the Queensland Government recently announced that Queensland households will receive a $1000 rebate on their electricity bill from July 2024.[20]

We encourage customers facing hardship to contact their retailer to discuss support measures that may be available to them (Box 2).

We also acknowledge stakeholder comments around the type and structure of (regulated) retail tariffs available, and eligibility conditions. These include enabling large customers to access 'solar soaker' type tariffs (such as the small business tariff 22C),[21] enabling a cohort of large customers to access consumption-based charging,[22] establishing a new time-of-use tariff targeted towards electric vehicles,[23] as well as generally streamlining tariff structures to make them more transparent and user-friendly.[24] However, this approach would not be consistent with the N+R framework, which involves us using the network tariff structures as a basis for the retail tariffs we set. This includes using the same time-of-use charging windows and customer eligibility conditions as those applied at the network-level.

[16] Compared to SEQ, electricity needs to be transported over longer distances and to a lower density customer base.
[17] Queensland Government, *Budget Strategy and Outlook 2023–24*, Budget Paper 2, June 2023, p 209.
[18] Appendix A2, Minister's letter and correspondence.
[19] BRIG, sub 1, p 3; QFF, sub 5, p 4.
[20] Queensland Government, *Miles government delivers $1,000 for Queensland households*, Media Statement, 2 May 2024.
[21] BRIG, sub 1, p 3; Cotton Australia, sub 2, p 2.
[22] Cotton Australia, sub 2, p 2.
[23] EVC, sub 3, pp 2–3.
[24] QFF, sub 5, p 5.

Box 2: Summary of support measures for electricity customers in regional Queensland

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

Hardship policies

Under the National Energy Retail Law, retailers have obligations to help customers in financial hardship or facing payment difficulties.

Ergon Energy Retail's Customer Assist program is available to eligible customers 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 due to an unforeseen emergency or a short-term financial crisis that has occurred in the past 12 months.

The Electricity Tariff Adjustment Scheme helps businesses transition from obsolete to standard tariffs by providing rebates on their electricity bills (eligibility requirements apply; closed to new participants).

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.

Resources for stakeholders include:

- QFF's website, which 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
- Ergon Energy Retail's website, which provides a range of information to assist customers, including households, businesses and farming customers
- The Australian Government's energy.gov.au website, which provides advice for households and businesses on how to manage bills and improve energy efficiency, and sets out the rebates and assistance available in different jurisdictions, including Queensland.

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.

4 Individual cost components

Notified prices are made up of several cost components – network costs (the N component) and retail costs (the R component) are the largest components. Other costs and adjustments are discussed in 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.[25] The costs are regulated by the AER and reflected in the network prices it approves.

We set the N component in a manner that reflects the overarching framework matters – that is, the UTP and N+R methodology (see chapter 3). This is consistent with the requirements of the delegation[26] and the broader pricing approach applied in previous price determinations. Table 4.1 sets out our basis for determining the N component.

We are mindful some stakeholders would prefer the Solar Bonus Scheme (SBS) charges not to be included in notified prices and would like these charges itemised in the notified price build-up.[27] 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.

Table 4.1: Basis for determining the N component

Tariff	Basis
Small customers	
Flat and secondary load control tariffs	Relevant Energex network prices (being the charges and tariff structures levied by Energex in SEQ).
Limited access obsolete tariffs (tariffs 62A, 65A and 66A)	Relevant network prices for Ergon Distribution's east zone, transmission region one.[a]
All other existing retail tariffs	Relevant Energex network prices but utilising Ergon Distribution tariff structures.
Large customers	Relevant network prices for Ergon Distribution's east zone, transmission region one (being the Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM).

[a] These tariffs are only available in the Ergon distribution area.

[25] In Queensland, these charges include the Solar Bonus Scheme and Australian Energy Market Commission levy costs.
[26] Appendix A1: Minister's delegation, schedule, cl 2(b).
[27] BRIG, sub 1, p 3; Cotton Australia, sub 2, p 2.

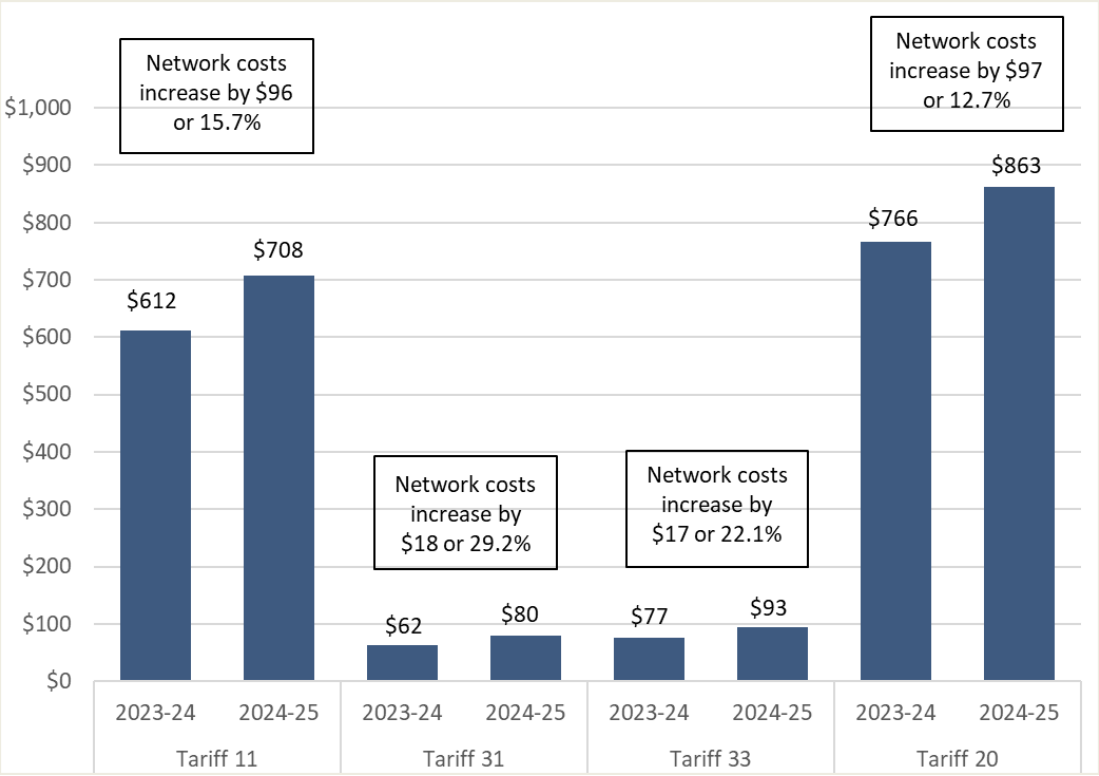
We have used draft network prices Ergon Energy Network and Energex submitted to the AER on 28 March 2024.[28] We intend to use the AER-approved network prices in our final determination, pending the availability of this information at the time we make our final determination.[29]

Network costs included in draft notified prices

Network costs have increased for small and large customers compared to last year – the increase to the annual bill for a typical customer is set out in Figures 4.1 and 4.2.[30]

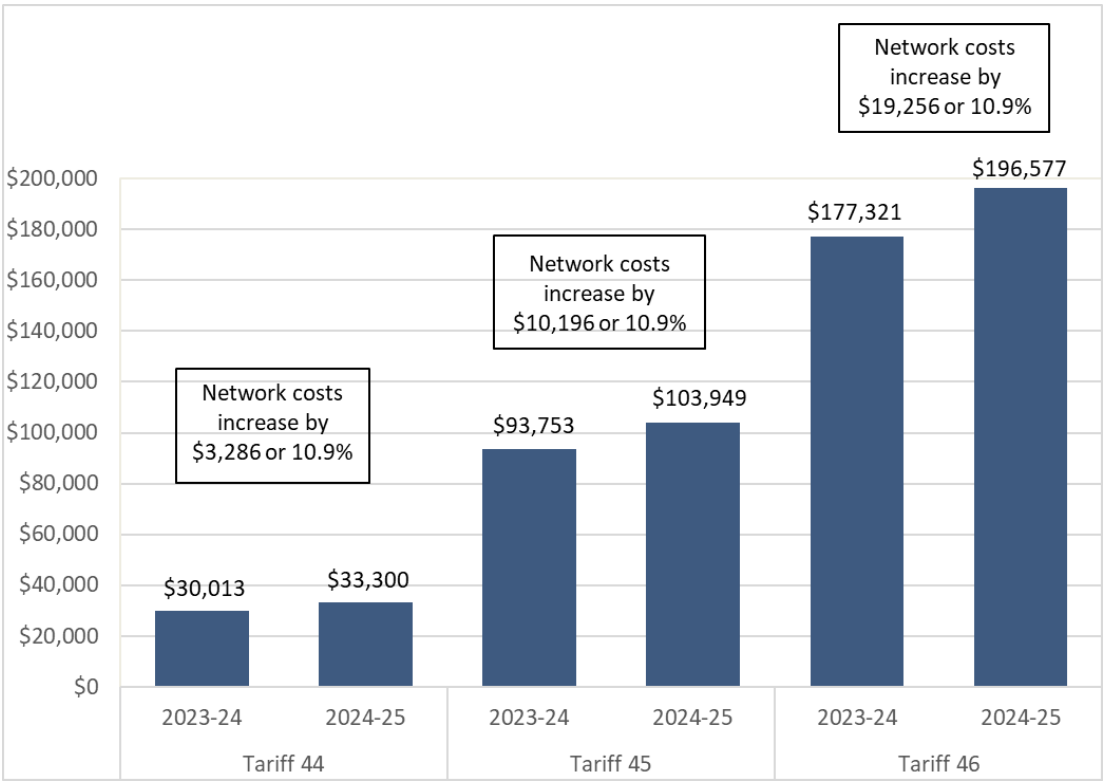
Importantly, a customer's actual bill will vary based on their consumption, as well as the application of any government rebates or concessions, such as the $1000 cost of living rebate for households recently announced by the Queensland Government.

Figure 4.1: Draft network costs – small customer bills (incl. GST)



[28] See Ergon Energy network prices for 2024–25 and Energex network prices for 2024–25 (as submitted to the AER).
[29] If the AER has not published approved network prices by the time we make our final determination, we will continue using the draft network prices. If the AER-approved prices differ from the draft prices, we will consider using a cost pass-through mechanism to adjust for material differences in the future if we are delegated this task.
[30] The change to the annual bill is based on unrounded values.

Figure 4.2: Draft network costs – large customer bills (incl. GST)



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 and provide metering related services.

4.2.1 Energy costs

Energy costs include costs associated with wholesale energy costs (WEC) – which are the costs of purchasing electricity from the National Electricity Market – as well as other energy costs (including the Renewable Energy Target) and energy losses.

This year, we engaged ACIL Allen (ACIL) to provide expert advice and inform our review and energy cost estimates. All information we relied on for this draft determination in ACIL's draft report is available on our website. This report will be updated for use in our final determination.

Wholesale energy costs

WEC relates to the costs retailers incur when purchasing electricity from the NEM to meet the electricity demand of their customers. Retailers typically adopt a range of strategies to reduce their exposure to rapidly changing wholesale electricity prices (spot prices)[31] when purchasing from the NEM, including pursuing hedging (financial), contractual and operational strategies.[32]

[31] Spot prices are settled every 5 minutes and currently can range from -$1000 to $17,500 per MWh.
[32] See ACIL's draft report, p 7–8.

Our WEC estimates are based on ACIL's advice that uses:

- **a market hedging approach** – that estimates the WEC for a retailer that hedges spot price risk (through ASX Energy contract data)
- **the latest available information** – to take into account the current environment (this includes ASX Energy contract data up until February 2024).

This is broadly consistent with the approach in previous years (described in Box 3), although we have made some refinements to improve our estimates this year (discussed in the next section).

Box 3: Estimating the WEC

Broadly, the estimated WEC for a given year is a function of:[33]

- **Wholesale energy spot prices** –simulated to reflect:
  - supply dynamics in the NEM, including thermal powerplant availability, renewable energy traces and more general information (e.g. the costs of supply and the operating characteristics of generators)
  - demand variations, based on ACIL's weather-influenced simulations of hourly demand using temperature data, historical demand profiles, the expected uptake of rooftop solar and the Australian Energy Market Operator's (AEMO's) latest demand forecasts
  - bidding behaviour of generators in the NEM, including potential changes in bidding caused by changing market conditions and underlying costs.
- **Retailers' hedging strategies and contract prices** –using a hedging model to simulate the WEC incurred by a retailer that manages spot price risk using publicly available standard ASX Energy base and cap contracts:
  - contract prices are estimated using the trade-weighted average of ASX Energy contract prices of quarterly base and cap contracts,[34] using contract prices and trade volumes for Queensland until 12 February 2024 inclusive.
  - Trading of ASX contracts tends to commence several years before the relevant financial year. For example, trading for 2024–25 ASX Energy quarterly contracts commenced in 2021. This reflects how market participants (such as retailers) purchase ASX contracts to lock in their costs in advance to manage spot price risk.

The hedging methodology (together with the simulated spot prices) produces 583 annual hedged energy cost estimates for a given demand profile. The 95th percentile of this distribution of hedged costs is used as our estimate of WEC. The 95th percentile is chosen, as it reduces the risk of understating the WEC that a prudent retailer faces in the NEM.[35]

[33] This summarises various aspects of ACIL's report relevant to setting out the method for estimating the WEC. See ACIL's draft report (pp 13-15, 19-25).
[34] Consistent with the 2023–24 review, calculations of the trade-weighted contract price take into account additional data on call options for base contracts. See ACIL's report, p 40.
[35] Another reason for adopting the 95th percentile is that, in the NEM, prices can increase significantly more than they can decrease.

We consider this approach is transparent and likely to produce WEC estimates that reasonably reflect the expected market conditions for a given determination year.[36] It uses a significant number of simulations and takes account of the latest available information.

While there has been a strong decline in wholesale spot prices over the past 12 months,[37] we would not necessarily expect a comparable decline in the WEC. The WEC estimates do take account of spot prices and any exposure the retailer may have to the spot market. However, it is the trade-weighted contract price, not the estimated spot price, that is a key driver of the WEC estimates. The trade-weighted contract price has stabilised at levels similar to those used for last year's determination.[38] This outcome reflects that a retailer builds up its contract position over time. In the case of the 2024–25 review, retailers purchased contracts from 2021, including during periods when contract prices were at elevated levels.[39]

Consistent with past reviews, we intend to update the WEC estimates in the final determination, including to reflect updated market (contract) data and any other new information.

Refinements

This year, we have made refinements to the historical demand profiles[40] used to inform our WEC estimates.

Inclusion of solar photovoltaic (PV) export demand in advanced digital meter (ADM) profiles

ADM profile data was included for the first time in last year's review, recognising the continued penetration (and ongoing roll-out) of ADMs in Queensland.[41] This provided better information on customers' consumption patterns, but the data (available at that time) excluded demand satisfied by solar PV exports.

We have incorporated ADM profile data again, which was supported by Ergon Energy Queensland (EEQ).[42] As ADM data is now available that *includes* demand satisfied by solar PV exports, we have used this to estimate the WEC. This better reflects the actual demand satisfied by a retailer (and used to develop its supply and hedging strategies).[43]

The refined ADM profile data results in a 'flatter' demand profile for residential and small business customers on tariffs 11 and 20, relative to last year.

[36] ACIL compared the WEC estimates produced by the approach in previous reviews against actual movements in the trade-weighted contract price to demonstrate that the approach produces estimates that align with what is observed in the market. See ACIL's draft report (p 51). The nature of the task (i.e. setting annual forward-looking prices) means there may be some differences between the estimated WEC for a given year and the actual WEC incurred by a prudent retailer. However, over the long run, we expect any under- or over-estimation to balance out. See ACIL's draft report (pp 24–26).
[37] The average annual spot price for Queensland has decreased from $144.97/MWh for 2022–23 to $84.64/MWh for 2023–24 to date. AEMO, *Average price*, accessed 14 March 2024.
[38] Trade-weighted base contract prices have decreased slightly, except for the Q2 2025 product, which has increased slightly. Cap contract prices have increased moderately for the Q1 2025 and Q2 2025 products. See ACIL's draft report (p 40).
[39] Contract prices declined around December 2022 and have since stabilised. However, the stabilised prices have remained elevated, compared to the prices observed in 2021 and the first half of 2022. See ACIL's draft report (p 41) for the possible drivers of these contract prices.
[40] ACIL's draft report specifies relevant historical demand profiles and sources (pp 10-11, 13).
[41] The Queensland Government is targeting 100% penetration of ADMs by 2030 (Queensland Government, *Queensland Energy and Jobs Plan: 2023 Update*, November 2023.
[42] EEQ, sub 4, p 1.
[43] See ACIL's draft report (pp 11-12).

Adjustments to account for AEMO's artificial uplift to the net system load profile (NSLP)

We typically use two to three years of historical net system load profile[44] data to inform our WEC estimates. In applying a consistent approach this year (i.e. considering NSLP data from 1 July 2021 to 30 June 2023), we have removed an artificial uplift included in the demand profile from 1 October 2021.

The artificial uplift was the result of a manual adjustment by AEMO[45] that ceased on 1 October 2023 and will not be present in 2024–25 (and will therefore not impact retailers). As such, we consider it appropriate to remove the artificial uplift[46] to better represent the NSLP applicable to retailers in 2024–25.

Outcomes and key drivers

Compared to last year, our draft estimates for WEC have decreased:

- for small customer tariffs – by between 3.9 and 16.1%
- for large customer tariffs – by around 6.9%.

The key drivers of the decrease are:

- **for small customer primary tariffs (tariffs 11 and 20)** – the 'flatter' demand profile (relative to last year) resulting from incorporating the refined ADM profile data (discussed above) into the demand profiles for these customers.[47] A 'flatter' demand profile results in lower hedging costs (all other things equal), by reducing the amount of over-hedging.[48] It also reduces the reliance on cap contracts, placing higher reliance on less expensive base contracts.[49,50]
- **for all other tariffs (tariffs 31, 33, 44, 45 and 46)** – the slight decrease in the trade-weighted price of base contracts relative to last year.
  As the demand profiles associated with these tariffs are relatively flat (compared to the small customer primary tariffs), retailers typically rely on less expensive base contracts to reduce their exposure to the spot prices.

Time-varying wholesale energy costs

For time-of-use tariffs 12C and 22C, we use time-varying WEC estimates to create stronger price signals (and greater price differentials between peak and non-peak periods) compared to tariffs 12B and 22B, on which these tariffs are based.

We set the time-varying WEC based on ACIL's advice, using the methodology developed last year (when these tariffs were introduced). This involves:

- using the WEC estimates for small customer tariffs 12B and 22B

[44] AEMO publishes the NSLPs used to approximate the demand of customers on accumulation meters.
[45] AEMO made these alterations to deal with issues relating to negative demand values coinciding with the commencement of 5-minute settlements. See ACIL's draft report (pp 15-17).
[46] ACIL's draft report (p 15-17) provides details on the approach used to remove the temporary uplift.
[47] Last year, demand satisfied by solar PV was excluded from the ADM profile data due to data constraints, resulting in lower demand during daytime periods and a peakier demand profile.
[48] In other words, reducing the extent to which contract levels exceed actual demand.
[49] For example, a perfectly flat demand profile (i.e. the same demand level for all hours across a year) can be perfectly matched with base contracts; hence, the WEC would simply equal the trade-weighted average base contract price.
[50] This counteracts the effects of continued uptake of solar PV (including the commissioning of utility scale solar), which has continued to drive down spot prices during the day, making it more costly to be over-hedged.

- 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 WEC 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 provide the desired price signals.

Table 4.2 sets out the time-varying WEC estimates included in draft notified prices this year.

Table 4.2: Time-varying WEC costs for tariffs 12C and 22C

Period	c/kWh
Peak (evening)	29.26
Non-peak (day)	4.68
Shoulder (night)	12.89

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.

Further information on tariffs 12C and 22C, including the intent of these tariffs, can be found in last year's determination.[51]

Other energy costs

Retailers incur a range of other energy costs when purchasing electricity from the NEM.

We estimate these costs based on ACIL's advice, which uses reliable sources of information and applies judgment to ensure these costs appropriately reflect those likely to be incurred by retailers.[52]

A description of the other energy costs and the approach used is set out in Table 4.3.

[51] Our 2023–24 final determination, sections 3.2.1 and 4.2.1.
[52] See ACIL's draft report (pp 26–33, 54-61).

Table 4.3: Other energy costs – description and estimation approach

	Description	Approach
Renewable energy target (RET) 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).[53]	LRET costs – estimated using forward prices for large-scale generation certificates (LGC) and renewable power percentage (RPP) values derived from mandated LRET targets and estimates of electricity acquisitions.
		SRES costs – estimated using the clearing house price for small-scale technology certificates (STC) and the small-scale technology percentage (STP).
NEM fees	Cover the costs to AEMO of operating the NEM.	Estimated using the latest data from AEMO, including historical costs and projected changes in costs.
Ancillary services	Cover the costs of services used by AEMO to manage power system safety, security and reliability.	Estimated using the average historical costs observed over the preceding 52 weeks, published by AEMO.
Prudential costs	Incurred to provide financial guarantees to AEMO and to lodge initial margins with the ASX for futures contracts.	Estimated using AEMO's prudential requirements and margin requirements for trading in the ASX futures market.
Energy losses	Associated with energy losses that occur when electricity is transported across the network, meaning retailers need to purchase more electricity than customers' demand.[54]	Estimated by applying the transmission and distribution loss factors published by AEMO, in a manner that aligns with AEMO's settlement process.

[53] LRET and SRES provide 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 LGCs and STCs. LGCs or STCs can be created when eligible electricity is generated by utility-scale renewable generators or small-scale renewable systems.
[54] Energy losses are applied to the sum of the WEC and all other energy costs to determine the associated cost.

We have not included any costs associated with the Reliability and Emergency Reserve Trader (RERT) scheme.[55] Based on available information, the RERT was not triggered in the 12 months prior to the draft.[56] The Bundaberg Regional Irrigators Group (BRIG) said that the RERT costs should be clearly identified in the cost stack and met by a separate CSO funded from Treasury.[57] Consistent with our requirements under the Electricity Act, we must have regard to the costs of supplying electricity, which include RERT costs.[58] Accordingly, RERT costs remain a relevant consideration for our final determination.

Compared to last year, our draft estimates for other energy costs have decreased:[59]

- for small customer tariffs – by 9.8% ($2.00/MWh)
- for large customer tariffs – by 5.7% ($1.08/MWh).

The changes to each cost category, and the reasons for these, are described in ACIL's report.[60]

We will update our estimates for the final determination to reflect any new information available. This includes considering any outstanding costs associated with the significant market events that occurred in June 2022, where finalised.[61]

Total energy costs included in draft notified prices

Total energy costs have decreased for small and large customers compared to last year – the decrease to the annual bill for a typical customer is set out in Figures 4.3 and 4.4.[62]

Importantly, a customer's actual bill will vary based on their consumption, as well as the application of any government rebates or concessions, such as the $1000 cost of living rebate for households recently announced by the Queensland Government.

[55] RERT costs are levied by AEMO to maintain 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.
[56] RERT costs are estimated using historical costs published by AEMO and do not include the June 2022 event costs. See ACIL's draft report (pp 28, 30).
[57] BRIG, sub 1, p 3.
[58] Electricity Act, s. 90(5)(a)(i).
[59] The reported change in other energy costs (compared to last year) excludes the costs associated with energy losses.
[60] The changes to each cost category are set out in ACIL's draft report (p 60).
[61] These are costs associated with the triggering of the administered price cap and suspension of the wholesale market from 12 to 23 June 2022. Some of the associated costs were included in 2023–24 notified prices. However, we understand there may still be outstanding costs, which are yet to be finalised.
[62] The change to the annual bill is based on unrounded values.

Figure 4.3: Draft energy costs – small customer bills (incl GST)

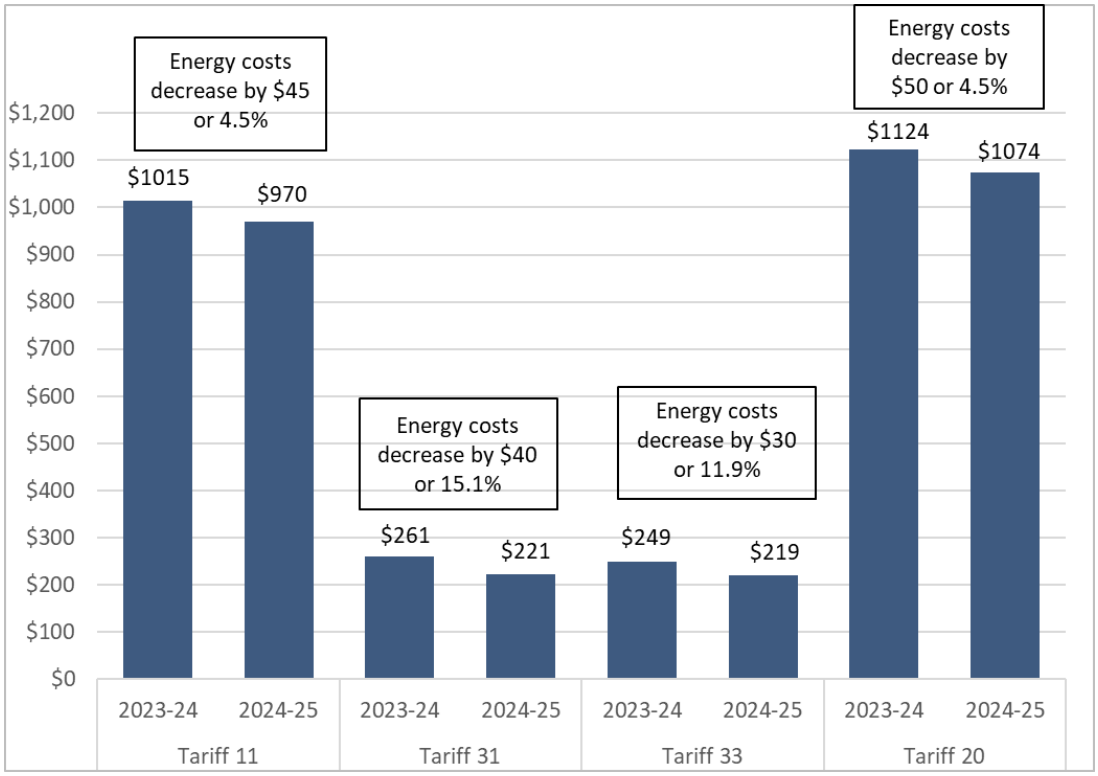
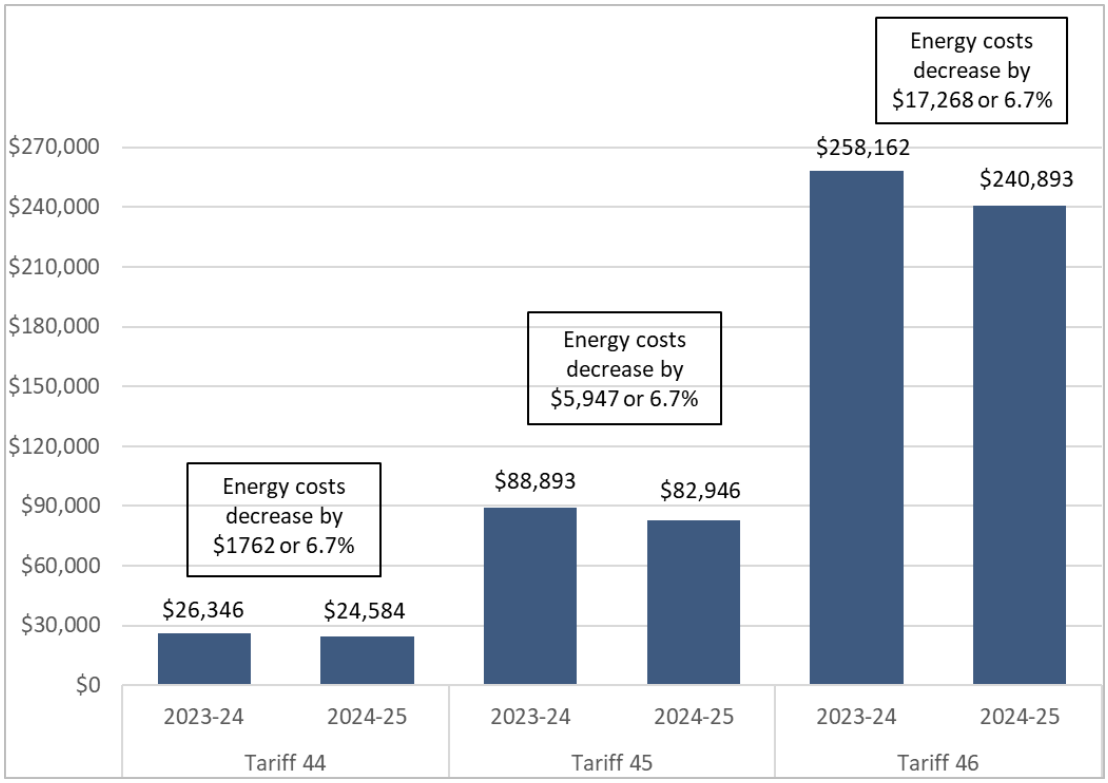


Figure 4.4: Draft energy costs – large customer bills (incl. GST)



4.2.2 Retail costs

Retail costs relate to the costs of running an electricity retail business. They 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.

We set retail cost allowances using an established benchmark.[63] This estimates the retail costs an efficient retailer would incur, based on market information. Table 4.4 sets out our basis for determining retail cost allowances.

Table 4.4: Basis for determining retail cost allowance and rates

Customer type	Basis
Small customers	Apply established benchmark costs (based on the costs of supply in SEQ) by: • adjusting last year's fixed retail costs[a] (for residential and small business) for inflation[b] to maintain fixed costs in real terms • maintaining the variable retail cost allocators at: – 7.25% for residential customers – 18.7% for small business customers
Large customers	Apply established benchmark costs (based on the costs of supplying large customers) by: • adjusting last year's fixed retail costs[a] for inflation[b] to maintain fixed costs in real terms • maintaining the variable retail cost allocator at 6.0445%.

a. Reflecting the established benchmark costs, adjusted for inflation each year since establishment.
b. We applied the RBA's CPI forecast of 3.1% for the financial year ending June 2025. See RBA, *Statement on Monetary Policy*, February 2024.

Metering service costs – small customers

Retail metering service costs relate to the ongoing capital and operating costs associated with customer meters, including the ongoing roll-out of ADMs in regional Queensland.

We have set these costs using the method established in last year's notified price review, updated to better align with the approach used by the AER in relation to ADM costs.[64] This method is based on the relevant costs of standard meters and ADMs in SEQ and the forecast rate of ADM deployment in regional Queensland.

[63] The benchmark retail cost allowances were first established in 2016–17, and then reviewed as part of our *2021–22 notified price review* – when the allowances for small customers were updated (based on market information) and the allowances for large customers were reviewed but ultimately maintained.
[64] QCA, *Regulated retail electricity prices in regional Queensland 2023-24*, final determination, June 2023, pp 16–17.

This approach allows retailers to recover costs associated with all metering services (including ADMs) and means customers contribute to the overall costs of metering services and pay the same amount, regardless of which type of meter they have.

These costs are incorporated into the daily supply charge for all small customer tariffs. We note stakeholders generally supported the ongoing roll-out and deployment of ADMs.[65]

Table 4.5 sets out our basis for determining the small customer metering costs.

Table 4.5: Draft metering costs for small customer tariffs, 2024–25 (excl GST)

Description	Metering costs	Approach
Primary tariff	23.307 c/day	We used relevant metering costs to apply in SEQ for: • type 6 meters, published by Energex[66] • ADMs, published by the AER.[67] We then calculated a weighted cost based on the forecast deployment rate of ADMs for small customers in regional Queensland for 2024–25, as provided by Ergon Retail.
Secondary tariff	3.532 c/day	We used relevant type 6 metering costs to apply in SEQ, provided by Energex. We did not include ADM costs, as customers with a secondary tariff will already pay for the ADM component through their primary tariff.

Compared to last year, the draft metering costs have increased to reflect updated information, including to better align with the AER's approach to ADM costs. We intend to use updated input information in our final determination, pending the availability of this information at the time we make our final determination.

Retail charge for manually reading a type 4A meter

There are costs involved with manual meter reads required if a customer has chosen to disable the remote communication function of the ADM.

We have been asked to consider setting a series of retail charges generally based on Ergon Retail's averaged costs for manually reading type 4A meters for customers within different feeder types (e.g. urban, rural or isolated) to better reflect the charges that could be incurred for different customer types.

Given the information available and advice from Ergon Retail, we have set this charge in the same manner as last year – being based on the AER-approved special meter read fee for Ergon Energy.

As a result, the retail charge is $43.05. [68]

[65] BRIG, sub 1, p 2; QFF, sub 5, p 5.
[66] We use draft Energex network prices for 2024–25 (as submitted to the AER).
[67] These are the same costs the AER uses to set the ADM costs included in the DMO charges for the Energex distribution area. See AER, *Draft determination – Default market offer prices 2024-25*, 19 March 2024.
[68] We use the draft special read meter fee in Ergon Energy network prices for 2024–25 (as submitted to the AER).

This continues to be a reasonable benchmark for setting this fee, given the lack of alternative cost information available and the few customers to which this applies.[69]

Stakeholders generally supported the fee (and the ability for Ergon Retail to recover the costs associated with manual meter reads) but said customers should have effective options for remote meter reading[70] and asked for data on the proportion of meter reads/bills based upon estimated readings.[71]

As disabling the communication function of an ADM is the customers' choice, this fee can be avoided (we understand this fee applies to very few customers).

Commentary on having a true-up mechanism

The retail metering service costs are set using the forecast deployment rate of ADMs for small customers in regional Queensland.

This year, we are required to consider a cost 'true-up' mechanism for small customer metering. This would allow any increased (or reduced) costs associated with actual ADM installations each year being recouped from (or returned to) customers in subsequent years.

As we set prices ahead of the year in which they apply, it is not possible to do a true-up this year. This is because we included retail metering costs using this approach (and forecast ADM deployment) for the first time in current (2023–24) notified prices, which apply until 30 June 2024. However, after this financial year, it would be possible to estimate any increased (reduced) costs associated with actual ADM installations, which could be considered in future (if included in the delegation).

We note stakeholders did not comment on this matter but may do so if it forms part of a future review.

Retail costs included in draft notified prices

Retail costs have increased for most small and large customers compared to last year – the change to the annual bill for a typical customer is set out in Figures 4.5 and 4.6.[72]

The retail costs for small customers include the cost of metering services (discussed above).

Importantly, a customer's actual bill will vary based on their consumption, as well as the application of any government rebates or concessions, such as the $1000 cost of living rebate for households recently announced by the Queensland Government.

[69] Ergon Retail advised that information on costs by feeder type is not available at this time, but instead provided information on annual costs (not costs per meter read) which we intend to investigate further.
[70] QFF, sub 5, p 6; Cotton Australia, sub 2, p 3.
[71] Cotton Australia, sub 2, p 3.
[72] The change to the annual bill is based on unrounded values.

Figure 4.5: Draft retail costs – small customer bills (incl. GST)

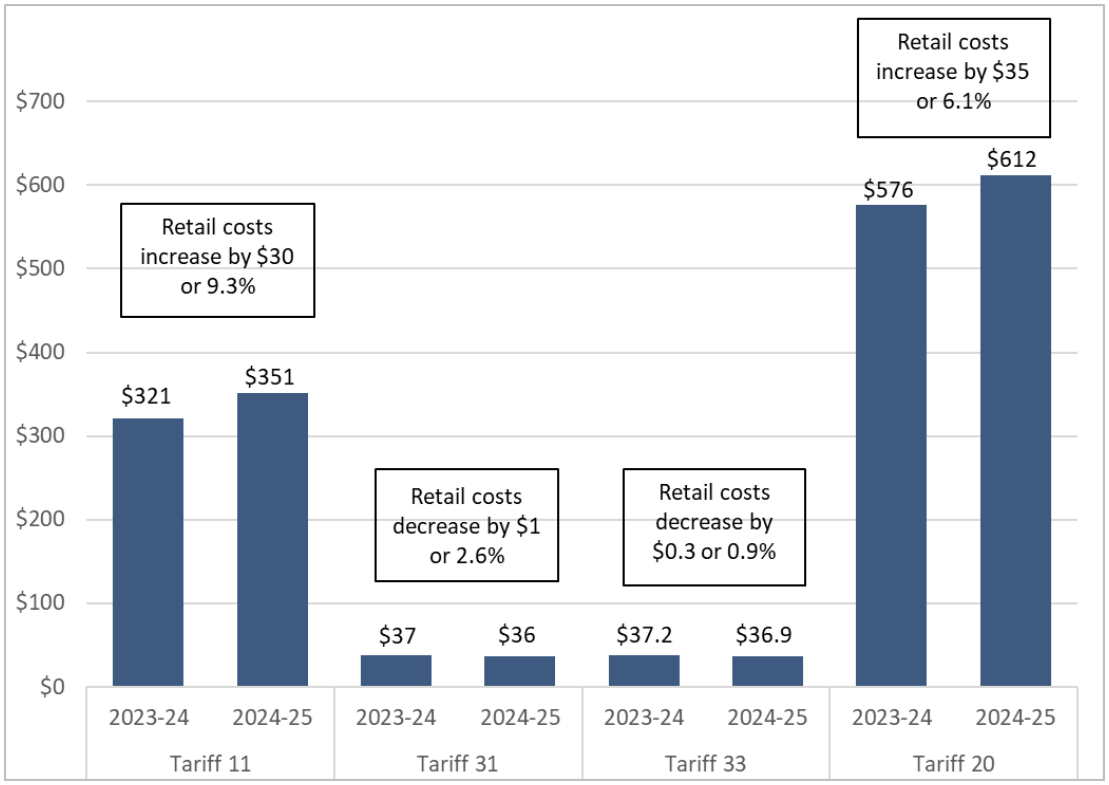
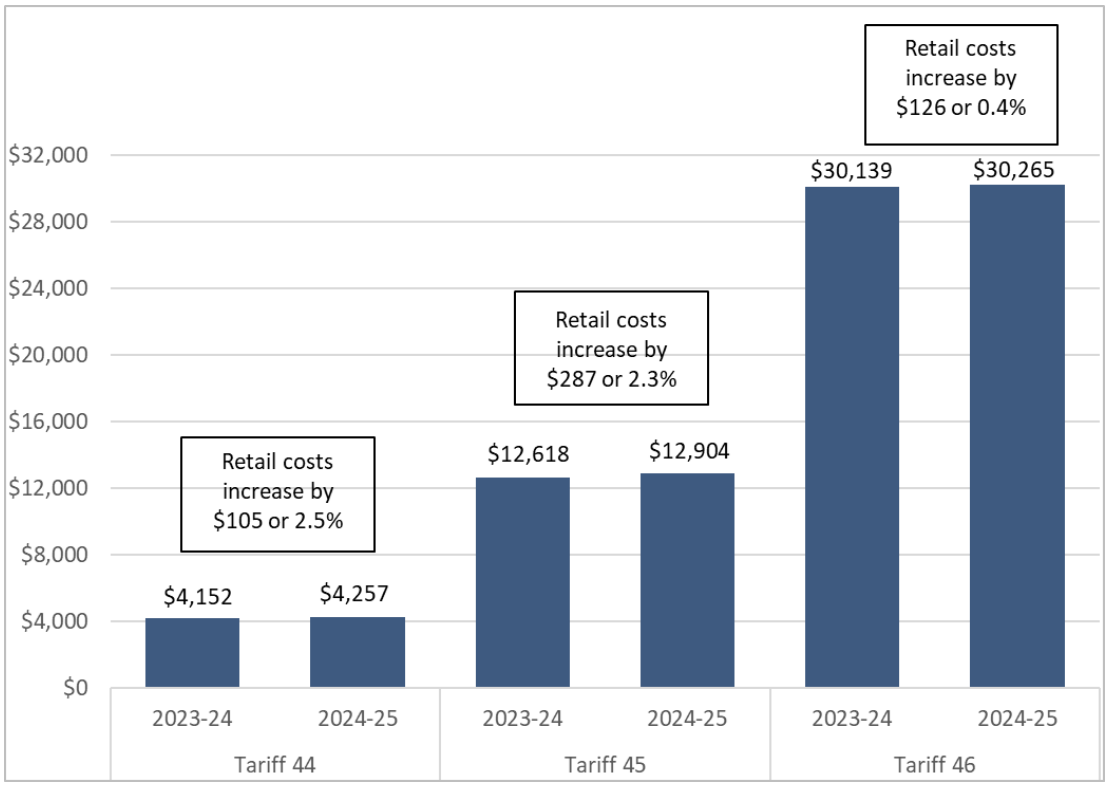


Figure 4.6: Draft retail costs – large customer bills (incl. GST)



5 Other costs and pricing matters

We have considered other costs and pricing matters when setting notified prices this year, including the standing offer adjustment, the recovery of small-scale renewable energy scheme costs and new matters relating to the existing default retail tariff arrangements.

5.1 Standing offer adjustment – small customers

The standing offer adjustment (SOA) is incorporated into small customer tariffs and is intended to reflect the value of more favourable terms and conditions in standard contracts relative to market contracts.[73]

We estimate the SOA based on an established method[74] that uses market information to assess the costs attached to SEQ market contracts (e.g. fees and charges a typical small customer in SEQ could incur). This market information acts as a proxy for the benefits of standard contract terms and conditions for customers in regional Queensland (e.g. fees and charges they could avoid).

Accordingly, we used 2022–23 SEQ market data[75] to:

- assess the range of fees and charges attached to retail market contracts in SEQ
- identify any additional fees in retail market contracts compared with standard contracts
- estimate the average additional costs that could be incurred by small customers on SEQ retail market contracts.[76]

On average, $55 of additional fees could be incurred annually by a small customer in SEQ on a market contract. The additional costs associated with fees and charges equate to around 3.45% of a typical small customer's annual bill.[77]

Based on our assessment, we consider 3.45% (of total costs) is an appropriate proxy for the value of the SOA to be incorporated into small customer notified prices this year. This value is subject to the default market offer (DMO) comparison, discussed below.[78]

[73] The inclusion of the SOA is consistent with the requirements of the ministerial delegation and is a long-standing practice in our price determinations.
[74] The method we use was established as part of the 2021–22 notified prices review.
[75] This data reflects our most recent review of retail fees in SEQ (QCA, *SEQ retail electricity market monitoring 2022–23*, December 2023, pp 45–56).
[76] The typical annual bill for small customers is based on June 2023 data from Appendix A of the QCA's *SEQ retail electricity market monitoring report 2022-23: Appendices*.
[77] This is based on the consumption of a typical customer – that is, the median (middle) customer in terms of consumption (based on June 2023 data from Appendix A of the QCA's *SEQ retail electricity market monitoring report 2022-23: Appendices*).
[78] Note, the QCA's estimated SOA of 3.45% has decreased compared to last year (e.g. of 4.56%), due to a decrease in average retailer fees and an increase in typical annual bills for small customers in SEQ. However, the SOA of 4.56% was subsequently reduced to 0% in last year's notified prices as a result of the DMO comparison.

DMO comparison

This year, as part of the application of the Queensland Government's UTP, we are required to consider the DMO reference bills for SEQ as a cap for notified price bills and use the SOA as the adjustment mechanism, with a negative Standing Offer Adjustment (SOA) to be applied if necessary.[79] As such, we compare the notified price bills (including the SOA) to the DMO reference bills in SEQ and assess whether we should discount the SOA.[80]

For the DMO comparison, we used the same approach as last year but updated it to take account of the 2024–25 draft DMO reference bills[81] recently published by the Australian Energy Regulator (AER). We:

- made adjustments to ensure a like-for-like comparison of DMO bills and notified price bills could be made. These adjustments included:
  - the goods and services tax (GST) – as GST is included in the DMO bills but not in our notified prices, we included the value of GST in our notified price bills
  - consumption levels – as consumption levels are different for the DMO bills, we have used the DMO consumption levels to calculate comparable notified price bills
  - the allocation for load control tariffs – to calculate a single DMO bill for tariffs 31 and 33, the AER uses an apportioning approach with an allocation of 29% for tariff 31 and 71% for tariff 33. We have applied the same approach to calculate a single notified price bill for load control tariffs
- compared the relevant notified price bills (including the 3.45% SOA) with the DMO reference bills for SEQ.

Based on this comparison, we found all relevant notified price bills exceeded the equivalent DMO reference bills (see Table 5.1).

On this basis, we consider it is appropriate to discount the value of the SOA incorporated into small customer notified prices. Based on guidance from the Minister, we consider doing this in a way that maintains the price relativity of small customer tariffs.[82]

As a result, we have discounted the SOA for:

- all residential customer primary tariffs – from 3.45% to –2.29% (reflecting the reduction required for tariff 11 when compared to the relevant DMO reference bill)
- all small customer secondary load control tariffs – from 3.45% to –6.20% (reflecting the reduction required for tariffs 31 and 33 when compared to the relevant DMO reference bill)
- all small business tariffs – from 3.45% to –7.18% (reflecting the reduction required for tariff 20 when compared to the relevant DMO reference bill).

Based on guidance from the Minister, we have applied a negative SOA to ensure notified price bills are not higher than the DMO reference bills – using this mechanism aligns with the intent of the UTP. We also consider this approach is consistent with the Minister's statement that, when making pricing decisions and striking the right balance between customer outcomes and retailer needs,

[79] Appendix A3, Minister's letter and correspondence.
[80] The AER sets four default market offer (DMO) reference bills for SEQ, for the following tariff groups: residential flat-rate tariffs, residential flat-rate with load control tariffs, residential time-of-use tariffs, and small business flat-rate tariffs. The DMO acts as a reference price to assist consumers in comparing market offers from electricity retailers and is intended to protect consumers in areas with no retail price regulation.
[81] AER, *Draft determination – Default market offer prices 2024-25*, 19 March 2024.
[82] Appendix A1 and A3, Minister's letter and correspondence.

where appropriate we should 'consider balancing the objectives toward consumer interests'.[83] Our approach also ensures that price relativity is maintained within each customer class[84] – by applying the same SOA discount to tariffs within the same customer class prevents some tariffs becoming more attractive.

We intend to update our assessment based on the reference bills in the AER's final DMO determination, which is due to be released in May 2024.

Table 5.1: DMO comparison with adjusted notified price bills (incl GST)[85]

Customer type	Relevant notified price tariff	DMO reference bill (A)	Notified price bill with 3.45% SOA (B)	Difference (B – A)	Notified price bill with discounted SOA (C)	Difference (C – A)
Residential	11	$2022	$2141	$119	$2022	$0
	12B	$2022	$2094	$72	$1978	($44)[a]
	11, 31 & 33	$2363	$2520	$157	$2363	$0
Small business	20	$4191	$4670	$479	$4191	$0

a. For tariff 12B, we applied a SOA of –2.29%, which reflects the reduction required to tariff 11 when compared to the relevant DMO reference bill. This has been done to ensure price relativity is maintained across the residential tariffs. The result is that the notified price bill for tariff 12B is below the relevant DMO reference bill by $44.

5.2 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, SRES liabilities for the first half of the financial year are known, while liabilities for the second half are based on forecasts from the CER.[86] 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.

There was an under-recovery of SRES costs for 2023–24 – the final SRES liabilities[87] were higher than forecast in last year's final determination (i.e. retailers have to purchase more certificates to surrender to the CER than initially forecast).

[83] Appendix A3, Minister's letter and correspondence.
[84] Customer classes are residential, small customer secondary load control and small business.
[85] Notified price bills presented include adjustments to provide a like-for-like comparison.
[86] The CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination.
[87] Reflecting the CER's final SRES liabilities for both calendar year 2023 and 2024. Clean Energy Regulator, *The small-scale technology percentage*, CER website, 20 February 2024.

We treat the under-recovery of SRES costs as a cost pass-through[88] in notified prices, which increases usage charges for all retail tariffs this year.[89]

This approach is consistent with past reviews and remains appropriate given the existing regulatory framework, as it aligns notified prices with the UTP-consistent costs of supply.

5.3 Metering costs – large customers

Consistent with our approach in previous determinations, we have estimated large customer ADM costs for 2024–25, using confidential data Energy Queensland provided for each large customer type.[90]

The metering charges for large customers are set out in chapter 6.[91]

5.4 Default retail tariff arrangements

Under the retail tariff schedule, if a small customer does not nominate a tariff when they become a standard contract customer of the retailer, then the retailer must assign the customer to tariff 11 (for residential customers) or tariff 20 (for small business customers). However, these default arrangements do not apply where the customer's metering configuration is for a primary interruptible supply tariff, in which case the customer must expressly nominate a tariff. Importantly, these default tariff arrangements do not prevent a customer from later requesting assignment to another tariff.[92]

The Minister's delegation requires us to consider whether there is an ongoing need for these default tariff arrangements.[93]

Subject to further information from stakeholders, we consider there is merit in retaining these default tariff arrangements at this time. The arrangements provide certainty to customers about which retail tariff a customer is assigned to in the event they have not nominated a tariff. This is particularly relevant where a customer has been deemed to have entered into a standard contract.[94]

Some stakeholders raised concerns about moving away from the default tariff arrangements at this time, particularly without clear safeguards being put in place. These safeguards included retailers demonstrating their commitment to investigating a customer's needs and likely consumption patterns and recommending an appropriate tariff for that customer with clear tariff comparisons provided in a bill format.[95]

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[88] 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. Such mechanisms are usually restricted to events outside the control of the regulated entity, such as SRES liabilities.
[89] See Appendix B for further detail on how we determine the SRES cost pass-through.
[90] In previous reviews, we also included confidential historical data from a small selection of other retailers. This information is now outdated and has not been included for this review.
[91] Metering charges for large customers are separately identified. This is different to the small customer metering costs, which are included in the R component for small customer tariffs.
[92] *Queensland Government Gazette No. 27*, vol 393, 9 June 2023, tariff schedule, p 179.
[93] Appendix A1: Minister's delegation, schedule, cl 2(d).
[94] For example, a deemed customer retail arrangement can apply when a small customer starts consuming energy at a premises without first applying to a retailer for the provision of customer retail services (i.e. a move-in customer) – see ss 54–55 of the *National Energy Retail Law (Queensland)* and division 8 of the National Energy Retail Rules.
[95] Cotton Australia, sub 2, pp 2–3; QFF, sub 5, p 5.

However, it may be difficult for retailers to be able to undertake these sorts of comparisons in circumstances where a deemed standard contract applies, given there will likely have been no contact between the customer and retailer, at least in the initial stage. More broadly, whether or not a customer will be better off on one type of tariff or another (such as a flat rate, time-of-use or demand tariff) will be influenced by the customer's consumption preferences, which a retailer may not be able to determine in a default tariff situation. While it is important for retailers to engage with customers and consider their needs and preferences, this may be more appropriately done through a retailer's initiatives to educate customers about available tariffs. For example, retailers typically make tools and resources available that can help customers compare their tariff options based on their individual circumstances.

While EEQ supported removal of the default arrangements at move-in for small customers, it did not provide any information on how it would treat customers who do not nominate a tariff when they become a standard contract customer.[96]

[96] EEQ, sub 4, p 1.

5.5 Additional issues raised by stakeholders

Stakeholders raised concerns in relation to policy matters, including:

- broader electricity regulation reforms – including making recommendations to government about reforms to allow the development of micro-grids and peer-to-peer trading, and amending regulations about the size of photovoltaic generators for solar exports,[97] as well as introducing a two-period feed-in tariff to support the effects of vehicle to grid technology[98]
- investment for renewable energy projects, and deployment of smart grid technologies – including to diversify the energy mix and provide other benefits, such as enhancing grid efficiency and reducing transmission losses. QFF said comprehensive programs should be developed to educate consumers about energy efficiency and the benefits of renewable energy[99]
- enhancements to information included in retail electricity bills – Cotton Australia considered that each retail bill should include a comparison of a customer's bill and the cheapest alternative tariff; and retailers should be obliged to educate customers without smart meters that further savings could be available if the customer had a smart meter installed[100]
- switchboard upgrades – BRIG asked us to consider a method and funding options for switchboard upgrades to allow an increased rate of smart meter uptake for small customers.[101]

These cover a range of matters beyond the scope of our review (see chapter 1). The Minister delegated the task of setting notified prices to us, but that does not unlock broader investigative and decision-making powers 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).

We encourage stakeholders to raise broader electricity policy and regulatory matters with the Queensland Government.

With regard to:

- information included in retail electricity bills – we note the AER is responsible for setting obligations that apply to retailers about the content of retail bills, including information about any better offers[102]
- switchboard upgrade funding options – the installation of a smart meter may require switchboard upgrades, but meter wiring and equipment to house meters are the customer's responsibility. It is not within scope of this notified prices review to consider methodology and funding options for switchboard upgrades.

[97] Cotton Australia, sub 2, p 2.
[98] EVC, sub 3, p 3.
[99] QFF, sub 5, p 5.
[100] Cotton Australia, sub 2, p 3.
[101] BRIG, sub 1, p 2.
[102] See AER, *Better bills guideline*, version 2, 30 January 2023.

6 Draft notified prices

Draft notified prices for 2024–25 are set out by customer type in tables 6.1 to 6.10.[103]

Table 6.1: Residential customers (excl. GST), 2024–25

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)	116.035	30.753			
Tariff 12B – residential time-of-use[b]	114.179	24.904	27.211	39.360	
Tariff 12C – residential time-of-use[b]	114.179	11.649	23.145	53.607	
Tariff 14A – residential time-of-use demand[c]	114.179	24.924			5.373
Tariff 14B – residential time-of-use demand[c]	114.179	24.122			9.429
Tariff 31 – night rate (super economy)	3.313	16.948			
Tariff 33 – controlled supply (economy)	3.313	18.824			

a. Charged per metering point.
b. Peak usage – 4 pm to 9 pm; off-peak (day) usage – 9 am to 4 pm; shoulder (night) usage – all other times.
c. Demand – 4 pm to 9 pm all days.

Table 6.2: Small business and unmetered supply customers (excl. GST), 2024–25

Retail tariff	Fixed[a]	Usage		Demand
		Off-peak/ flat	Peak	
	(c/day)	(c/kWh)	(c/kWh)	($/kW/mth)
Tariff 20 – business (flat-rate)	141.339	32.941		
Tariff 24A – business (time-of-use demand)[b]	139.483	28.934		5.481
Tariff 24B – business (time-of-use demand)[b]	139.483	27.896		11.336
Tariff 34 – business (interruptible supply)	130.572	22.506		
Tariff 91 – unmetered		30.598		

a. Charged per metering point.
b. Demand – 4 pm to 9 pm on weekdays.

[103] A breakdown of each notified price by cost component is provided in Appendix D. The draft gazette notice, which includes the draft notified prices published in a tariff schedule, and the terms and conditions for accessing each tariff, is provided in Appendix E.

Table 6.3: Small business customers (excl. GST), 2024–25

Retail tariff	Fixed band[a]					Usage		
	Band 1 (c/day)	Band 2 (c/day)	Band 3 (c/day)	Band 4 (c/day)	Band 5 (c/day)	Off-peak/flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)
Tariff 22B – small business time-of-use inclining band[b]	139.483	167.514	195.546	223.763	251.888	26.508	37.240	42.884
Tariff 22C – small business time- of-use inclining band[b]	139.483	167.514	195.546	223.763	251.888	12.572	32.965	57.863

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

Table 6.4: Large business and street lighting customers (excl. GST), 2024–25

Retail tariff	Fixed	Usage		Demand		Excess demand
	(c/day)	Off-peak/flat (c/kWh)	Peak (c/kWh)	Off-peak/flat[a] ($/kW/mth)	Off-peak/flat[a] ($/kVA/mth)	($/kVA/mth)
Tariff 44 – over 100 MWh small (demand)	4455.763	19.255		27.768	24.989	
Tariff 45 – over 100 MWh medium (demand)	14220.348	19.258		27.497	24.747	
Tariff 46 – over 100 MWh large (demand)	37276.506	18.798		26.903	24.213	
Tariff 50A – large business time-of-use demand[b]	17965.922	19.831			17.769	1.844
Tariff 60A – large business flat-rate interruptible supply (primary)	4390.363	24.914				
Tariff 60B – large business flat-rate interruptible supply (secondary)		24.914				
Tariff 71 – street lighting		30.674				

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: Very large business customers (excl. GST), 2024–25

Retail tariff	Fixed (c/day)	Usage (c/kWh)	Connection unit ($/day/unit)	Capacity ($/kVA of AD/mth)	Demand ($/kVA/mth)
Tariff 51A – high voltage (CAC 66 kV)	22065.059	14.928	7.402	3.676	4.230
Tariff 51B – high voltage (CAC 33 kV)	15776.259	14.928	7.402	4.409	4.380
Tariff 51C – high voltage (CAC 22/11 kV Bus)	14367.959	14.928	7.402	5.029	5.324
Tariff 51D – high voltage (CAC 22/11 kV Line)	13807.759	14.928	7.402	9.411	10.710
Tariff 53 – high voltage (ICC)	21858.344	14.928		3.676	4.230
ICC site-specific – high voltage	2784.544	12.735		0.210	0.241

Table 6.6: Very large business customers (excl. GST), 2024–25

Retail tariff	Fixed (c/day)	Usage		Connection unit ($/day/unit)	Capacity ($/kVA of AD/mth)	Demand ($/kVA/mth)
		Off-peak (c/kWh)	Peak (c/kWh)			
Tariff 52A – high voltage (CAC STOUD 33–66 kV)	11496.859	19.060	13.979	7.402	6.644	16.480
Tariff 52B – high voltage (CAC STOUD 22/11 kV Bus)	11496.859	19.060	13.979	7.402	4.778	52.591
Tariff 52C – high voltage (CAC STOUD 22/11 kV Line)	11496.859	19.060	13.979	7.402	8.509	62.451

Table 6.7 Large business customers (excl. GST), 2024–25

Retail tariff	Fixed	Usage[a]	
		Below threshold	Above threshold
	(c/day)	(c/kWh)	(c/kWh)
Tariff 43 – Business customer (over 100 MWh)	4390.363	20.267	29.578

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

Table 6.8: Limited-access obsolete tariffs – small business customers (excl. GST), 2024–25

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)	($/kW/mth)	($/kW/mth)
Tariff 62A – time-of-use declining block tariff[a]	120.377	73.404	61.893	25.198		
Tariff 65A – time-of-use tariff[b]	119.977	58.132		31.491		
Tariff 66A – dual-rate demand tariff[c]	268.177			29.851	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), 2024–25

Retail tariff	Fixed	Usage		Demand	
		Off-peak/flat	Peak	Off-peak/flat	Peak[a]
	(c/day)	(c/kWh)	(c/kWh)	($/kW/mth)	($/kW/mth)
Tariff 50 – over 100 MWh seasonal time-of-use (demand)	3969.122	22.847	16.752	11.815	79.959

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), 2024–25

Customer type	Metering charge (c/day)
Standard asset customer (annual usage of 750 MWh or less)	216.792
Standard asset customer (annual usage greater than 750 MWh)	260.243
Connection asset customer	429.001
Individually calculated customer	375.024

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	The delegation issued by the Minister for Energy, Renewables and Hydrogen (see Appendix A)
DMO	Default market offer
EEQ	Ergon Energy Queensland
Electricity Act	Electricity Act 1994 (Qld)
Ergon Distribution	Ergon Energy Corporation Limited (electricity distribution arm)
ICP	Interim consultation paper
kVA	Kilovolt amperes
kW	Kilowatts
kWh	Kilowatt hour
LGC	Large-scale generation certificate
LRET	Large-scale renewable energy target
MWh	Megawatt hour
N	Network costs
NEM	National Electricity Market
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
Notified prices	Regulated retail electricity prices
NSLP	Net system load profile
N+R	Network + retail cost build-up methodology
PV	Photovoltaic
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
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 5 submissions on our interim consultation paper (available on our website).

Stakeholder	Submission number	Date received
Bundaberg Regional Irrigators Group (BRIG)	1	19 January 2024
Cotton Australia	2	19 January 2024
Electric Vehicle Council (EVC)	3	18 January 2024
Ergon Energy Queensland (EEQ)	4	18 January 2024
Queensland Farmers' Federation (QFF)	5	1 February 2024

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