Queensland Competition Authority

Regulated retail electricity prices in regional Queensland for 2025–26

Draft determination

March 2025

Submissions

Closing date for submissions: 23 April 2025

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 Q 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**.

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1 About our review

Each year, we set regulated retail electricity prices for regional Queensland.

In December 2024, the Treasurer, Minister for Energy and Minister for Home Ownership (the Minister) delegated us the task of setting regulated retail electricity prices (notified prices) for regional Queensland in 2025–26.[1]

We set notified prices using a well-established framework, based on factors in the Electricity Act and matters in the delegation (Box 1), stakeholder submissions[2] and our own analysis.

This draft determination includes indicative notified prices only. It 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.[3]

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 Australian Energy Regulator (AER)) and adding retail and energy costs (which we determine)
- the Queensland Government's uniform tariff policy (UTP) – this ensures that, where possible, customers within the same class pay no more for their electricity, and can access similar pricing structures, regardless of their location. As a result, for most customers, prices are set below the actual cost of supply and are subsidised by the Queensland Government through a community service obligation payment.

[1] The delegation was issued in accordance with s 90AA of the *Electricity Act 1994* (Qld).
[2] We received 6 submissions on the interim consultation paper, which are available on our website.
[3] Electricity Act, s 90(5)(a). We may also have regard to any other matter we consider relevant (s 90(5)(b)).

1.1 Draft determination

This year, customers can expect an increase in their electricity bills – largely due to an increase in network costs, which is partially offset by a decrease in energy costs. Indicative customer bill impacts are discussed in chapter 2.

We also draw stakeholders' attention to the proposed changes to the existing suite of retail tariffs that are necessary to reflect the changes in underlying network prices expected from 1 July 2025 (see section 3.1).

The draft notified prices are bundled prices that reflect the retail tariff structure (except for site-specific tariffs).[4]

1.2 Consultation timetable

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

Figure 1.1: Stages of the review

We intend to hold information sessions on key aspects of our draft determination in April 2025. Further details on these sessions, including how to register to attend, are available on our website.

Stakeholders are invited to comment on our draft determination through written submissions.[5] We will consider all stakeholder submissions received, along with other relevant information, when making our final determination.[6]

Submissions on the draft determination are due by 23 April 2025.

[4] As required in cl 8 of the schedule to the Minister's delegation (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.
[5] See the submissions page at the start of this report for information on making a submission, including where to access our submission policy and online submission form.
[6] We encourage stakeholders to subscribe to our email alerts to keep up to date with the latest developments on this project.

1.3 Supporting information

Supporting information available on our website includes:

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

1.4 Human Rights Act declaration

In accordance with the *Human Rights Act 2019* (Qld) (s 58), we have assessed the compatibility of our draft determination with human rights. As our draft determination pertains to the prices that individuals, as consumers, pay for electricity, we have considered the following human rights that may be relevant:

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

Our view is that this draft determination is compatible with human rights under s. 8(a) of the Human Rights Act. In 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.[7]

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

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

2 Indicative customer bills

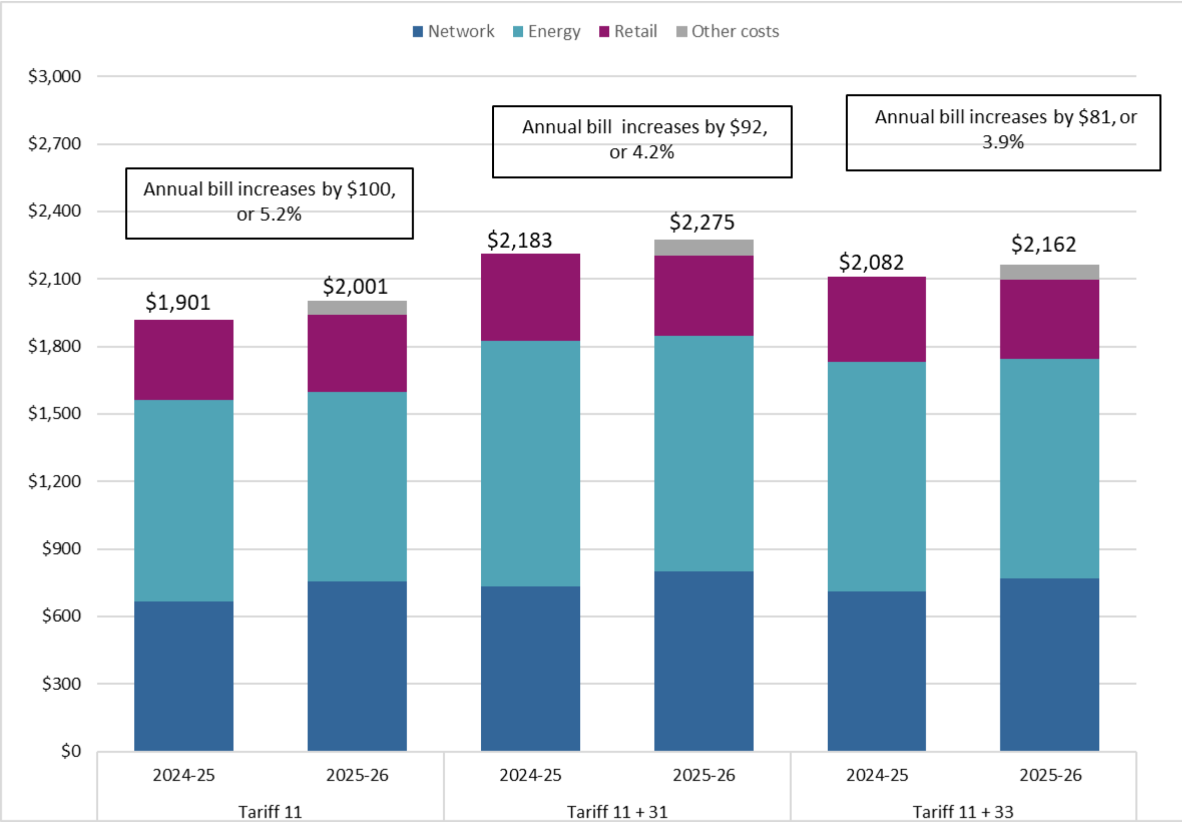
Overall, we forecast an increase in the underlying cost of supplying energy to most customers – which is reflected in the notified prices.

Importantly, the draft customer bill estimates are for guidance only.[8] Each customer's actual bill will vary depending on their electricity consumption. For personalised advice and further information, customers should engage with their retailer.[9]

2.1 Small customer bills

Typical customers on the main residential tariff (tariff 11) are expected to pay around 5.2% more for electricity in 2025–26 (Figure 2.1). However, customers on secondary load control tariffs (tariffs 31 and 33) may see some offset, as those tariffs are expected to decrease in 2025–26.

Figure 2.1: Residential customer bills, 2024–25 and 2025–26 (incl GST)



Note: As other costs for residential customers are negative in 2024–25, they do not appear in the figure above.

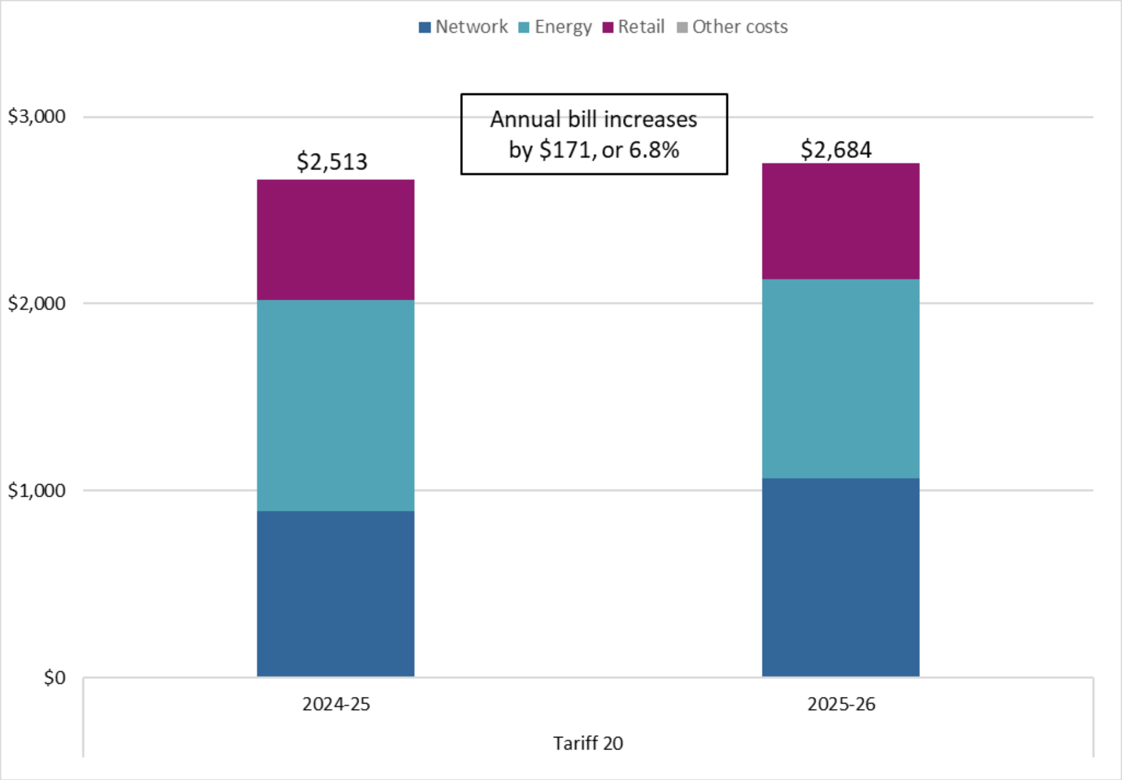
[8] For the final determination updates to input costs may change the notified prices and bill impacts shown, including those highlighted in this report (e.g. draft network prices – see section 4.1) and the standing offer adjustment (section 5.1).

[9] 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 E provides the consumption data used to estimate these bills).

Small business customers

Typical customers on the main small business tariff (tariff 20) are expected to pay around 6.8% more for electricity in 2025–26 (Figure 2.2). However, customers on secondary load control tariffs (tariffs 31 and 33) may see some offset, as those tariffs are expected to decrease in 2025–26.

Figure 2.2: Small business customer bills, 2024–25 and 2025–26 (incl GST)



Note: As other costs for small business customers are negative in 2024–25 and 2025–26, they do not appear in the figure above.

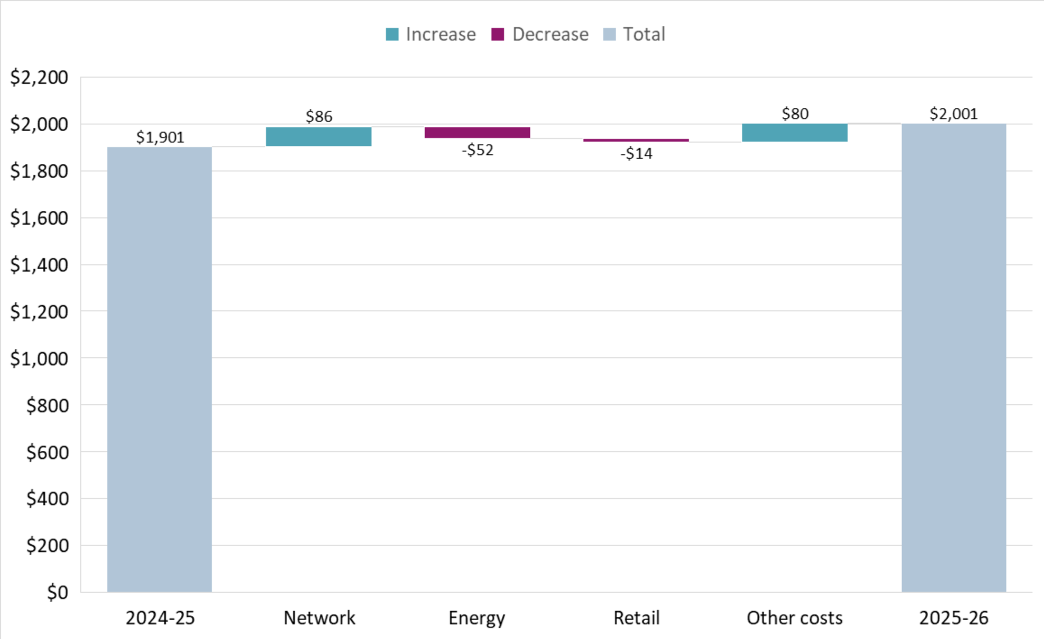
Key drivers

The increases to notified prices are driven by changes to costs that retailers incur, which can vary depending on the tariff type. This year:

- tariffs 11 and 20 – the main residential and small business customer flat tariffs – have increased due to the increase in network costs, which outweighs a decrease in energy costs
- tariffs 31 and 33 – secondary load control tariffs – have decreased, reflecting a decrease in network costs.

Figure 2.3 provides the breakdown of individual cost components that contribute to the overall bill increase for a typical customer on tariff 11.

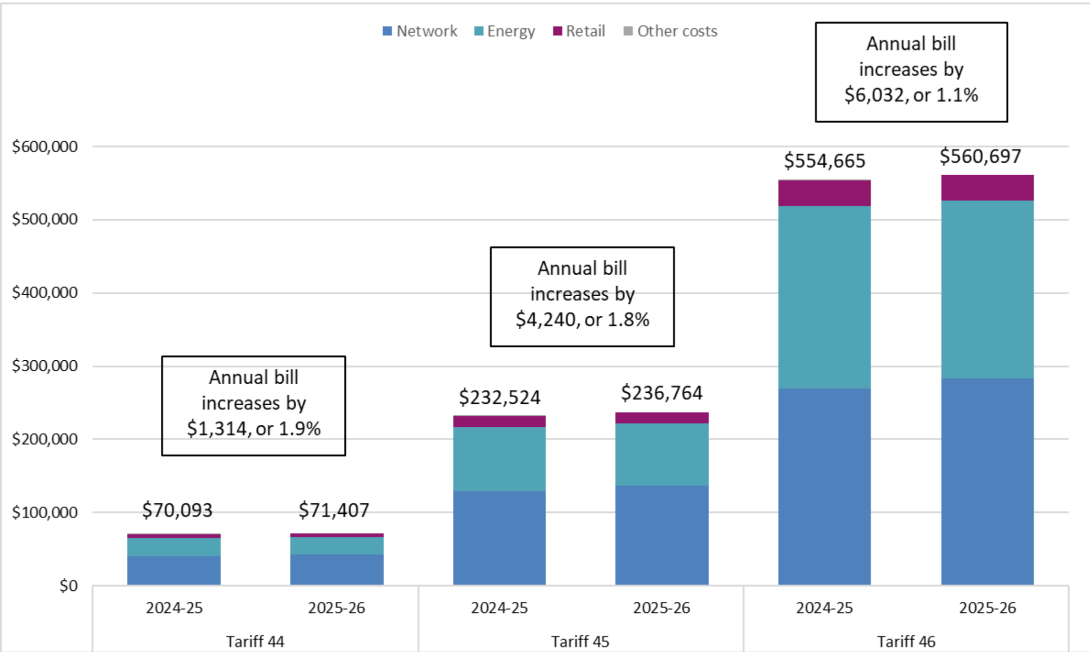
Figure 2.3: Tariff 11 bill – changes in cost components, 2024–25 and 2025–26 (incl GST)



2.2 Large customers

Typical customers on tariffs 44, 45 or 46 are expected to pay around 1.1% to 1.9% more for electricity in 2025–26 (Figure 2.4). The increase in these is mainly driven by an increase in network costs, although this is partially offset by a decrease in energy costs.

Figure 2.4: Comparison of large business customer bills for 2024–25 and 2025–26 (incl GST)



Note: As other costs for large business customers are negative in 2025–26, they do not appear in the figure above. Other costs were positive in 2024-25. 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 takes into account the cost level, structure, and availability of tariffs, while 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 the relevant factors outlined in the Electricity Act and the matters specified in the Minister's delegation (see Chapter 1). Specifically, the delegation requires us to consider:

- **the Queensland Government's UTP:** This policy ensures 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. Additionally, we apply the default market offers (DMOs) set by the Australian Energy Regulator (AER) for southeast Queensland (SEQ) to cap notified prices for small customers, as detailed in section 5.1.
- **the N+R cost build-up methodology:** This methodology sets notified prices by treating the N component (network costs) as a pass-through and determining the R component (energy and retail costs) ourselves.

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

Table 3.1: Overarching framework matters

Matter	Effect
Queensland Government's UTP	This means generally basing notified prices on: • for small customers – the cost of supplying small customers in south-east Queensland (SEQ) • for large customers – the costs of supplying large customers in Ergon Distribution's east zone transmission region one, which is the region with the lowest supply cost connected to the National Electricity Market (NEM).
N+R cost build-up methodology	This means: • basing the retail tariffs on 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).

We understand concerns around electricity prices and affordability in regional Queensland. Some stakeholders believe the current pricing framework is outdated and advocate for a fair and affordable tariff of no more than 16c/kWh.[10] However, the legislative framework mandates that we set prices based on the actual cost of electricity supply, rather than the price preferred by stakeholders.

The Queensland Government's UTP is a policy that helps provide more affordable electricity prices in regional Queensland. By considering the UTP when setting prices, we can set lower prices than would otherwise be possible due to the higher cost of supply in regional Queensland.[11] The UTP works by having the Queensland Government subsidise the difference between the cost of supply and the prices customers pay through a community service obligation (CSO) subsidy, expected to be around $603 million in 2024–25.[12]

Some stakeholders raised broader issues around the CSO payment, overarching framework used to set prices, customer support options and available retail tariffs:

- Bundaberg Regional Irrigators Group (BRIG) said the CSO should be paid to Ergon Network, rather than Ergon Retail, to facilitate retail competition.[13]
- Caravan Parks Association of Queensland (CPAQ) recommended that regional Queensland caravan parks receive tailored support, such as grants or subsidies, to improve infrastructure and help park operators optimise energy consumption and achieve cost savings. It also recommended retaining, redesigning, or creating tariffs for seasonal and high-usage businesses like caravan parks, promoting flexible load control tariffs, and reforming demand and service charges to encourage renewable energy adoption.[14]
- Electric Vehicle Council (EVC) said the N+R methodology is outdated and the Minister should allow more flexibility in creating retail tariff structures for regional Queensland, noting particular retailers have developed alternative time-of-use (TOU) tariffs for electric vehicles (EVs) that are not available in regional Queensland.[15] EVC also said reliance cannot be placed on network tariff structures to appropriately underpin retail tariff structures when regulatory resets occur once every 5 years.[16]

We acknowledge that these concerns, some of which have been raised in the past, are matters stakeholders consider valid and important to address. While we acknowledge the significance of these concerns, it is important to note that addressing these broader issues falls outside the scope of our price review. For instance, we do not have the authority to modify and/or implement support measures beyond those already provided by the Queensland Government.

Our focus during price reviews is primarily on setting the notified prices using those methods and approaches specified by the Minister. Under the N+R framework, we base retail tariffs on the tariff structures, TOU windows and eligibility conditions of the underlying network tariffs. That said, the Minister could direct us to modify or introduce retail tariffs to meet policy objectives or relevant energy-related initiatives. For instance, we continue to set some retail tariffs with stronger pricing signals (the 'solar soaker' tariffs) based on advice from the Minister in previous reviews. As such, we suggest any broader issues and recommendations (such as those discussed above), are best raised directly with the Minister.

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[10] BRIG, sub 1, p 1.
[11] Compared to SEQ, electricity needs to be transported over longer distances and to a lower density customer base.
[12] Queensland Government, *Budget Strategy and Outlook* , Budget Paper 2, Queensland Budget 2024–25, June 2024, p 219.
[13] BRIG, sub 1, p 2.
[14] CPAQ, sub 2, pp 9–11.
[15] EVC, sub 3, pp 2–3.
[16] EVC, sub 3, p 3.

Customers facing hardship should contact their retailer to discuss potential options available. Various support measures are available (see Box 2).

Box 2: Summary of customer support measures 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, 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 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:

- QFF's website, which provides information and resources on electricity prices, understanding your bill, government schemes and concessions, industry specific information and available programs
- 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.

3.1 Changes to network tariffs

Under the N+R framework, the network prices and tariffs structures approved by the AER serve as the foundation for the retail tariffs we set. The AER is currently assessing proposed changes to network tariffs that impact a number of the retail tariffs we set (see Box 3).

This year, the Minister has asked us to assess the network tariff changes and consider whether retail tariffs based on network tariffs that may become obsolete should be phased out gradually (with a transition period) or become obsolete within the tariff year.[17]

Box 3: Network tariffs for 2025–30

The AER is assessing Energex and Ergon Distribution's network revenue and tariff proposals for 2025–30.[18] Key changes include:

- adding TOU charges to various tariffs (including small customer demand tariffs) and changes to demand charges that affect tariffs 44 and 50A
- changes to the TOU charging windows for small and large customer tariffs:
  - the off-peak window will be changed to 11 am – 4 pm for residential customers and to 11 am –1 pm for small and large business customers
  - the peak window will be changed to 5 – 8 pm on weekdays (for small and large business customers)
- removal of small customer tariffs 14B and 24B and the large customer tariffs 45, 46, 52A, 52B and 52C
- the introduction of new network tariffs from 1 July 2025, including high voltage CAC and dynamic flex storage tariffs.[19]

The AER is expected to make its final determination in April 2025. After that, Energex and Ergon Distribution will submit network prices for 2025–26 to the AER for approval (to apply from 1 July 2025).

Stakeholders had mixed views on implementing the network tariff changes, including whether a transition period was necessary:

- EEQ preferred that changes to network tariffs be immediately reflected in the notified prices, without a transition period. EEQ confirmed it can implement these changes by 1 July 2025 and emphasised that it is important that customers can access enhanced tariff structures without delay.[20] However, EEQ proposed a 12-month transition period for tariff 44, as some customers will need equipment upgrades due to the removal of the option for kW-based demand charges.[21]

[17] Minister's delegation, schedule, cl 2(c).
[18] The regulatory proposals include tariff structure statements, which set out the network tariffs each distributor proposes to have in place over the regulatory period. More information about Energex and Ergon Distribution's regulatory proposals can be found on the AER's website.
[19] On 6 February 2025, Energex and Ergon Distribution proposed an amendment to their revised tariff structure statements that postponed the small customer flexible load tariffs until a later date (likely 1 July 2028, or potentially earlier, pending resolution of system capability issues).
[20] EEQ, sub 4, p 3.
[21] EEQ, sub 4, p 3.

- Some stakeholders raised concerns, including whether customers will be better off (financially) and the potential confusion, costs and uncertainty these tariff changes may cause.[22]
- BRIG expressed interest in changing the TOU windows for small and large business customers to help their members manage (and optimise) energy use and costs better.[23]
- several stakeholders proposed that a transition period should be provided for all retail tariffs affected by changes to underlying network tariffs[24] or at least to retail tariffs that are to be withdrawn.[25]
- QFF proposed a 3-year transition period for tariffs that are to be extinguished.[26]

We acknowledge stakeholders' views, including that new tariff structures should be introduced in a timely manner. We propose to incorporate all changes made to the underlying network tariffs, noting the AER is reviewing these changes through its process – and the network tariffs, once they are approved, will necessarily form the basis of the retail tariffs we set under the N+R framework. The introduction of new retail tariffs is discussed separately below.

However, we also acknowledge the potential for customers to be impacted by the changes and have carefully considered whether a transition period may be appropriate, taking into account:

- the materiality of the change to the tariff
- the availability of alternative tariff options for affected customers
- the number of affected customers.

As a result, we propose:

- for most affected retail tariffs, that:
  - the tariff be made an obsolete tariff and a 12-month transition period be provided
  - a new tariff be set based on the new network tariff structure (if the underlying network tariff has not been withdrawn)
- for some affected retail tariffs, that there be no transition period and changes be implemented from 1 July 2025.

See Table 3.2 for an overview of our draft decision on each affected retail tariff. More details are in Appendix B.

We consider a 12-month transition period is reasonable. This timeframe allows affected customers time to understand changes to their tariff and prepare for pricing under a new tariff structure. At the same time, it minimises the period of misalignment between network and retail tariffs.

The use of a transition period will have implications for the calculation of the network costs used as part of the cost build-up for these tariffs – this is discussed in section 4.1.

We note stakeholders' comments about the importance of detailed customer engagement, including education and advisory services, to help customers understand changes to tariff structures and how they can benefit, as well as providing comparison tools to help customers explore the tariff options available.[27] Customer engagement is a key part of a retailer's business,

[22] CPAQ, sub 2, p 7; QFF, sub 6, pp 4–5.
[23] BRIG, sub 1, pp 1–2.
[24] QFF, sub 6, pp 4–5; CPAQ, sub 2, p 8.
[25] BRIG, sub 1, p 2.
[26] QFF, sub 6, p 4.
[27] QFF, sub 6, pp 4–6; CPAQ, sub 2, pp 7–10.

and we encourage retailers to develop resources to help customers understand their tariff options. We note EEQ's statement that it is already working on customer communications plans.[28]

Without limiting submissions, we seek information from retailers about any plans to communicate changes to tariff structures to their customers before 1 July 2025.

We may make further changes to the retail tariff schedule once the AER's final decision has been made, including to any relevant definitions (such as definitions for CAC and ICC customer types).

Table 3.2: Draft decision on retail tariffs impacted by network tariff changes

Retail tariff	Draft decision
Small customer tariffs	
12B	Implement change to tariff structure immediately without a transition period.
12C	Implement change to tariff structure immediately without a transition period.
14A	Implement change to tariff structure immediately without a transition period.
14B	Extinguish tariff immediately without a transition period.
22B	Make tariff obsolete with a 12-month phase-out date and introduce a new standard retail tariff based on the new tariff structure (new tariff 22D).
22C	Make tariff obsolete with a 12-month phase-out date and introduce a new standard retail tariff based on the new tariff structure (new tariff 22E).
24A	Make tariff obsolete with a 12-month phase-out date and introduce a new standard retail tariff based on the new tariff structure (new tariff 24C).
24B	Extinguish tariff immediately without a transition period.
31	Implement change to tariff structure immediately without a transition period.
33	Implement change to tariff structure immediately without a transition period.
Large customer tariffs	
44	Make tariff obsolete with a 12-month phase-out date and introduce a new standard retail tariff based on the new tariff structure (new tariff 44A).
45	Make tariff obsolete with a 12-month phase-out date.
46	Make tariff obsolete with a 12-month phase-out date.
50A	Make tariff obsolete with a 12-month phase-out date and introduce a new standard retail tariff based on the new tariff structure (new tariff 50B).
52A	Make tariff obsolete with a 12-month phase-out date.
52B	Make tariff obsolete with a 12-month phase-out date.
52C	Make tariff obsolete with a 12-month phase-out date.
60B	Implement change to tariff structure immediately without a transition period.
Existing obsolete tariffs	
50	Set a 12-month phase-out date.

[28] EEQ, sub 4, p 3.

Retail tariff	Draft decision
62A	Set a 12-month phase-out date.
65A	Set a 12-month phase-out date.
66A	Set a 12-month phase-out date.

New retail tariffs

In addition to changes to existing network tariffs, Energex and Ergon Distribution have proposed new network tariffs to commence from 1 July 2025.

Our draft decision is to establish new standard retail tariffs based on the following new network tariffs:

- large TOU energy tariff – new retail tariff to be designated as tariff 49
- CAC HV line TOU demand tariff – new retail tariff to be designated as tariff 52G
- CAC HV bus TOU demand tariff – new retail tariff to be designated as tariff 52F
- CAC 33kV TOU demand tariff – new retail tariff to be designated as tariff 52E
- CAC 66 kV TOU demand tariff – new retail tariff to be designated as tariff 52D.

We consider there is reasonable certainty around these network tariffs and sufficient time to establish the corresponding retail tariffs within our notified prices process.

However, we do not propose to establish retail tariffs based on the proposed dynamic flex storage network tariffs as part of this notified prices process. These tariffs are more novel, and there is currently less certainty surrounding them, including potential changes the AER may require in its final decision. While we appreciate these tariffs were developed to offer customers more options (and offer benefits to the network) and that stakeholders may want these to be implemented immediately, we consider more time is needed to evaluate these tariffs once finalised at the network level. This will allow us to consider how best to incorporate them into notified prices, including addressing any retail-specific issues that may arise in the retail tariff schedule.[29]

EEQ suggested that all new tariffs be gazetted as 'available at retailer discretion' to give retailers the time needed to implement the tariffs in their billing system and conduct compliance checks, similar to the approach used at the start of the 2015–20 (network) regulatory period.[30]

However, in the absence of further details from retailers regarding these required actions and timeframe, our preference is to make these tariffs available at the start of the tariff year. We seek further information from retailers on whether there would be any issues with implementing the new tariffs by 1 July 2025 or if they should be deferred to a future notified prices determination.

In this draft decision, we use tariff numbering that closely matches the existing tariffs that are being replaced. We are open to considering alternative numbering suggestions if stakeholders consider it would better serve retailers and/or customers.

We recognise the timing of our notified prices process and the AER's network regulatory process creates complexity, as the network tariff arrangements are being finalised at the same time as our

[29] We note it is open for the Minister to issue a further delegation during 2025–26 to add these tariffs into the retail tariff schedule before the next notified prices determination for 2026–27. This has occurred in previous reviews.
[30] EEQ, sub 4, p 3.

process, which we are required to complete by 7 June 2025. Our decision on these matters may change depending on the AER's final decision on the network tariffs.

4 Individual cost components

The notified prices mainly consist of network costs (N component) – for electricity transport (via distribution and transmission networks) – and retail costs (R component) – for buying and selling electricity to customers – along with other costs.[31]

We use the N+R cost build-up methodology to set notified prices by:

- setting the N component – based on network prices to be approved by the AER (in this report we are using draft prices provided by Ergon Energy Network and Energex)
- determining the R component – to reflect the costs an efficient retailer incurs in buying and selling electricity, including wholesale energy costs (WEC), other NEM-related costs, and the costs of operating a retail business.[32]

4.1 Network component

The N component includes costs for electricity transport through transmission and distribution networks, as well as jurisdictional scheme charges[33]. 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 and the broader pricing approach applied in previous determinations.

This year, there are two new matters impacting the N component:

- The cost of legacy (accumulation) meters is now included in network prices to be approved by the AER.[34]

  As a result, legacy metering costs will be captured in the network prices. We have removed them from small customer retail metering costs to avoid double-counting.[35]

- We are maintaining some retail tariffs that no longer have an underlying network tariff (see section 3.1).

  As a result, we will need to use a price indexation approach to set the N component for these retail tariffs. This approach uses the approved 2024–25 network prices and adjusts these by the AER's nominal x-factor. We then include relevant jurisdictional scheme charges and legacy metering costs, consistent with the way these costs are now captured by the AER. Further detail on the indexation method and how it is applied is in Appendix C.

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[31] These other costs and related adjustments are discussed in chapter 5.
[32] For small customers, we also include the cost of metering services in the R component, to reflect the ongoing rollout of advanced digital meters in regional Queensland (see section 4.2).
[33] In Queensland, these charges include the Solar Bonus Scheme and Australian Energy Market Commission levy costs.
[34] The AER sets out the reasons for this approach in its review of Energex and Ergon Energy Network's revenue proposals for 2025–30. For example, see AER, *Energex Electricity Distribution Determination 2025 to 2030: Overview*, draft decision, September 2024, p 23.
[35] This issue is detailed in section 4.2.

Some stakeholders raised concerns about:

- Solar Bonus Scheme (SBS) charges being included in network prices, including that SBS costs should be itemised and, ultimately, not paid for by customers in notified prices.[36]
- Indexation of the N component for tariff 44, which is the only tariff EEQ considers should be indexed; EEQ also considers it may be appropriate to tie the indexation to the change in the underlying N for T44 kVA.[37]
- the tight timeframes and whether the AER-approved network prices will be used in the final notified prices. [38]

As jurisdictional scheme charges (including SBS charges) are included in the AER-approved network prices, these are included in the N component for notified prices.

We have applied the indexation approach to determine the N component for retail tariffs that no longer have an underlying network price (see Appendix C). Importantly, this approach accounts for expected changes in network costs determined by the AER and can be applied consistently across all existing retail tariffs without an underlying network tariff. The use of the price indexation approach will be limited to the 2025–26 period, as the relevant retail tariffs are set to be discontinued after a 12-month period (see Chapter 3).

For this draft determination, draft network prices that Ergon Energy Network and Energex provided were used, as AER-approved prices were not available. We intend to use the AER-approved network prices in our final determination, subject to the availability and timing of this information.[39] Table 4.1 sets out the basis on which we determine the N component.

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 Energy Network's east zone, transmission region one.[a]
All other existing retail tariffs	Relevant Energex network prices but utilising Ergon Energy Network's tariff structures
Large customers	Relevant network prices for Ergon Energy Network's east zone, transmission region one (being the Ergon Energy pricing region with the lowest cost of supply that is connected to the NEM).
All tariffs made obsolete, with a 12-month transition period	Relevant 2024–25 network prices, adjusted by the AER's nominal x-factor and including legacy metering and relevant jurisdictional scheme charges.

a These tariffs are only available in the Ergon Energy area.

[36] BRIG, sub 1, p 2.
[37] EEQ, sub 4, p. 3.
[38] EEQ, sub 4, p. 3.
[39] 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 AER-approved prices then 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.

Network costs included in draft notified prices

Network costs have increased for most small and large customers compared to last year. In part, this is due to the inclusion of legacy metering costs in the N component in 2025–26.[40] The change to the annual bill for a typical customer is set out in Figures 4.1 and 4.2.[41]

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

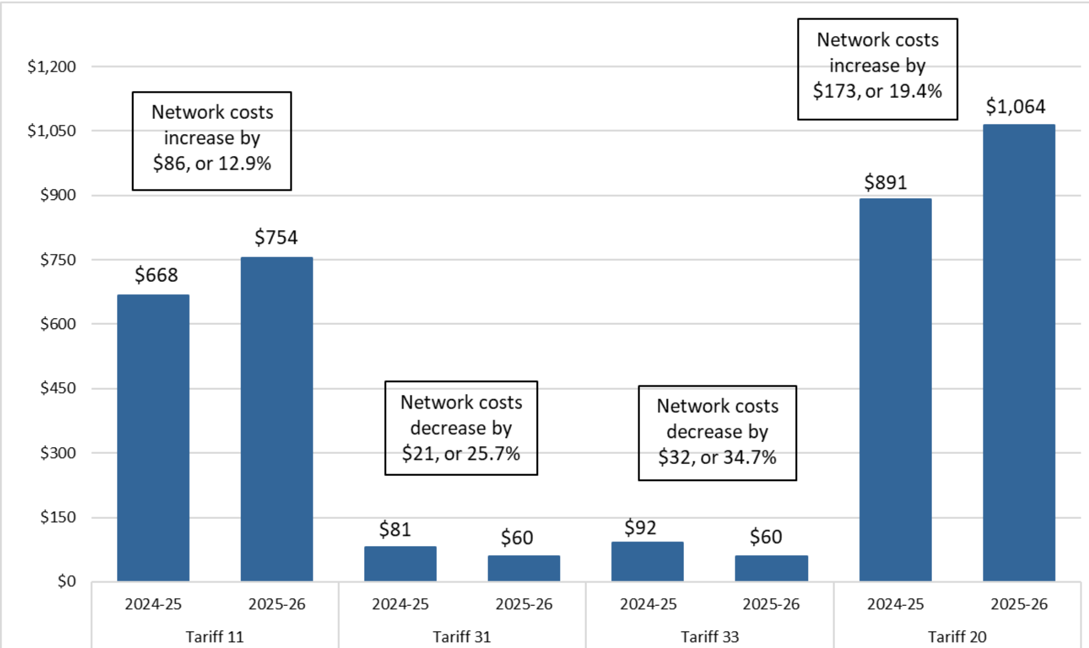
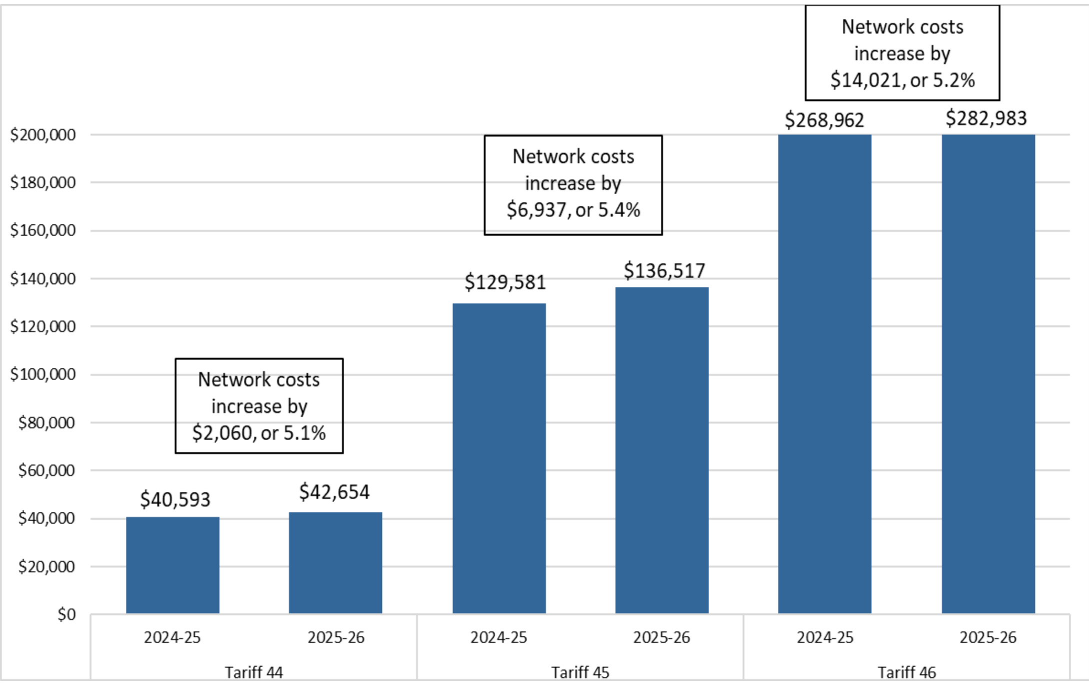


Figure 4.2: Draft network costs – large customer tariffs (incl GST)



[40] These costs were previously included in the R component, as discussed in section 4.2.
[41] Amounts presented are rounded. Percentage changes are based on unrounded amounts.

4.2 Retail

The R component includes energy costs and retail costs. It covers the costs retailers incur to buy electricity from the NEM, run their operations and provide metering-related services to customers.

4.2.1 Energy costs

Energy costs include wholesale energy costs (WEC), which are the costs of purchasing electricity from the NEM, as well as other energy costs like costs related to the Renewable Energy Target and energy losses.

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

Wholesale energy costs

The WEC relates to the costs retailers incur when purchasing electricity from the NEM to meet customer demand. To manage the impact of fluctuating electricity prices (spot prices), retailers use strategies like financial hedging, contracts and operational methods.[42]

Our WEC estimates are based on advice from ACIL, using:

- **a market hedging approach** – which estimates wholesale energy costs for a retailer that hedges spot price risk using ASX Energy contracts
- **the most up to date information** – including contract data up to 21 February 2025.

This method is the same used in previous years (explained in Box 4).

[42] Spot prices are settled every 5 minutes and currently can range from –$1000 to $20,300 per MWh.

Box 4: Estimating the WEC

The estimated WEC for a given year is based on:[43]

- **wholesale energy spot prices** – which are simulated by considering:
  - supply factors in the NEM, such as powerplant availability and renewable energy production
  - demand changes, based on weather data, historical demand, solar uptake and demand forecasts from the Australian Energy Market Operator (AEMO)
  - the way generators bid in the market, including potential changes in their bidding based on market conditions and costs
- **retailers' hedging strategies and contract prices** – which are estimated using a model to simulate the WEC for a retailer managing spot price risk through (publicly available) ASX Energy contracts:
  - contract prices are estimated using the trade-weighted average of ASX Energy contract prices for quarterly base and cap contracts,[44] based on trade data for Queensland up to 21 February 2025
  - ASX contract trading usually begins several years before the relevant financial year, like in mid- to late 2022 for 2025–26 contracts, reflecting how retailers lock in their costs early.

This method produces 594 annual hedged energy cost estimates. We use the 95th percentile of these estimates as our WEC, which reduces the risk of understating the costs a prudent retailer would face in the NEM.[45]

This year, we have made a minor refinement to how we consider historical demand profiles (discussed below). We consider our approach is likely to produce robust WEC estimates that reflect current market conditions and are transparent.[46] The approach uses a significant number of simulations and the latest available information.

EEQ noted that retailers are using 'shaped' contracts due to the growth in solar generation, which impacts demand. EEQ suggested using an estimate of a shaped contract price to obtain a more market-reflective WEC.[47] While we recognise that shaped contracts are used, information on the

[43] This summarises key aspects of ACIL's report that are relevant to the method used for estimating the WEC. See ACIL's draft report, pp 7–21.
[44] Consistent with past reviews, calculations of the trade-weighted contract price take into account additional data on call options for base contracts. See ACIL's draft report, p 39.
[45] Another reason for adopting the 95th percentile is that in the NEM, prices can increase significantly more than they can decrease.
[46] ASX Energy contract information is readily available online. Additionally, ACIL compared the WEC estimates produced in previous reviews against actual movements in the trade-weighted contract price and found they were generally closely aligned. See ACIL's draft report, p 50. 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 22–25.
[47] EEQ said this data would be reported to the AER from April 2025. As shaped contracts usually apply to the morning and evening peak periods, EEQ recommended scaling up the base contract price by the ratio of the evening peak spot price to the flat spot price. See EEQ, sub 4, p 1.

extent of their use, and how the market values them, is not transparent as they are not offered through ASX Energy. We will continue to monitor their use and transparency.[48]

EEQ also said that the traded volume of ASX caps does not fully represent a hedge portfolio since a lot of trades are speculative. It suggested open interest in cap products is a better indicator of the volume of caps available for hedging.[49] We consider the hedging strategy we use to estimate the WEC is appropriate, even if it differs from how retailers actually hedge. Our hedging strategy is only intended to proxy the range of hedging instruments available. Retailers use various strategies that differ from this proxy, including non-ASX-listed instruments.[50] Therefore, we do not consider the difference in cap contracts is problematic.[51]

As in past reviews, we intend to update the WEC estimates in the final determination, taking into account updated market (contract) data and any other new information.

Historical demand profiles

We continue to combine the net system load profile (NSLP)[52] with advanced digital meter (ADM) data when considering historical demand profiles. Consistent with our 2024–25 review, the ADM data *includes* demand from solar PV exports, as this better reflects the actual demand a retailer needs to supply its customers.[53]

Normally, we use two to three years of historical demand data for our WEC estimates, but this year we have used data from 1 October 2023 to 30 September 2024. This allows us to avoid including an artificial increase in NSLP demand from 1 October 2021 to 30 September 2023, which was caused by a manual adjustment by AEMO.[54] This adjustment will not be present in 2025–26 and will not affect retailers. We have also confirmed that this data has enough variation to be reliable.

Outcomes and key drivers

The WEC has decreased for most customers compared to last year:

- the WEC for small customer primary tariffs decreased by around 5.3% However, the WEC for small customer load control tariffs (tariffs 31 and 33) increased by about 7.0%
- the WEC for large customer tariffs decreased by around 0.5%.

[48] See ACIL's draft report, pp 33–34.
[49] EEQ, sub 4, p 2.
[50] For example, such strategies include utilising over-the-counter (OTC) contracts, power purchase agreements (PPAs) and investing in their own generating units.
[51] See ACIL's draft report, p 34.
[52] AEMO publishes the NSLPs used to approximate the demand of customers on accumulation meters.
[53] See ACIL's draft report, pp 11–12.
[54] 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, p 15.

The key drivers of these changes are:

- **for small and large customer primary tariffs (tariffs 11, 20, 44, 45, 46)** – the demand profiles have flattened (relative to last year),[55] which lowers a retailer's hedging costs (all other things equal), including by reducing the amount of over-hedging.[56]
- **for small customer load control tariffs (tariffs 31 and 33)** – the trade-weighted price of base contracts has increased (relative to last year), along with higher gas prices, which are relevant due to the shape of the associated demand profiles.[57]

Time-varying wholesale energy costs

For time-of-use tariffs 12C, 22C and 22E, we use time-varying WEC estimates to create stronger differences between peak and non-peak periods, compared to tariffs 12B, 22B and 22D, which these tariffs are based on.[58]

We set the time-varying WECs based on ACIL's advice, using the same method applied in previous years. This involves:

- using the WEC estimates for small customer tariffs 12B, 22B and 22D
- creating weightings for different times of the day based on the distribution of demand-weighted spot price variations throughout the day. Non-peak periods (daytime) generally have lower prices, while peak periods (evening) have higher prices. The time periods are based on network tariff structures that are approved by the AER[59]
- applying these weightings to the WEC estimates (described above) to set lower rates for non-peak periods and higher rates for peak periods.

This method maintains the same total WEC as for tariffs 12B, 22B and 22D but changes how costs are spread throughout the day to strengthen price signals. Table 4.2 sets out the time-varying WEC estimates included in draft notified prices this year.

Table 4.2: Time-varying WECs for tariffs 12C, 22C and 22E

Period	Tariff 12C[a] c/kWh	Tariff 22C[b] c/kWh	Tariff 22E[c] c/kWh
Peak (evening)	24.37	24.37	23.41
Non-peak (day)	3.96	4.42	3.57
Shoulder (night)	14.16	15.57	14.04

a. For tariff 12C, peak usage is 4 pm to 9 pm all days; off-peak (day) usage is 11 am to 4 pm all days; shoulder (night) usage is all other times.
b. For tariff 22C, peak usage is 4 pm to 9 pm weekdays; off-peak (day) usage is 9 am to 4 pm all days; shoulder (night) usage is all other times.
c. For tariff 22E, peak usage is 5 pm to 8 pm weekdays; off-peak (day) usage is 11 am to 1 pm all days; shoulder (night) usage is all other times.

[55] The flatter profiles reflect the continued roll-out of ADMs, allowing us to account for demand satisfied by solar exports. Because of data constraints, the NSLP excludes demand satisfied by solar exports – resulting in lower demand during daytime periods and a peakier demand profile. For the ADM profile, we can include demand satisfied by solar exports.
[56] In other words, reducing the extent to which contract levels exceed actual demand.
[57] The load control demand profiles are peaky during the late evening period, when gas prices influence spot price outcomes – and gas prices have been higher.
[58] The basis for this approach can be found in our 2023–24 final determination, sections 3.2.1 and 4.2.1. As we are proposing to make tariff 22C obsolete with a 12-month transition period, we applied a time-varying WEC to the new retail tariff, 22E.
[59] Some network tariffs (and time periods) have changed and are yet to be approved by the AER (see section 3.1).

Other energy costs

Retailers incur other energy costs when buying electricity from the NEM. We estimate these costs based on ACIL's advice, which uses reliable sources and ensures the costs appropriately reflect what retailers are likely to pay.[60]

Table 4.3 provides more details on these costs and how we estimate them.

[60] See ACIL's draft report, pp 25–32, 53–60.

Table 4.3: Other energy costs – description and estimation approach

	Description	Approach
Renewable energy target (RET) costs	Costs related to buying certificates to meet the mandated RET targets, which include the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).[61]	LRET costs – estimated using forward prices for large-scale generation certificates (LGC) and renewable power percentage (RPP) values, based on the mandated LRET targets and estimates of electricity acquisitions.
		SRES costs – estimated based on the clearing house price for small-scale technology certificates (STC) and the small-scale technology percentage (STP).
NEM fees	The costs to AEMO for operating the NEM.	Estimated based on the latest AEMO budget report, which includes both a fixed and variable component.[62] We used the 2024–25 budget for the draft determination and will update this if the 2025–26 report is available before the final determination.
Ancillary services	The costs of services used by AEMO to maintain power system safety, security and reliability.	Estimated using the average historical costs from the past 52 weeks, published by AEMO.
Prudential costs	The costs of providing 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	The costs related to energy losses that happen when electricity is transported across the network, so retailers need to buy more electricity than what customers actually use.[63]	Estimated by applying transmission and distribution loss factors published by AEMO. We used 2024–25 data and will update this if new information is available before the final determination.

[61] LRET and SRES are meant to encourage the electricity sector to increase generation from renewable energy and reduce greenhouse gas emissions. Retailers pay for these incentives by buying LGCs and STCs. LGCs or STCs are created when eligible electricity is generated by large or small renewable energy systems.

[62] See ACIL's draft report, p 25. The fixed NEM fee is recovered in the daily supply charge as a fixed energy cost component. This differs to 2024–25 where fixed NEM fees were captured in the (fixed) retail cost component for presentational purposes.

[63] Energy losses are applied to the sum of the WEC and all other energy costs to determine the associated cost.

With regard to LRET costs, EEQ said the current method for determining the LGC price did not reflect actual practices, as it assumes all certificates are bought in the forward market, when some are also purchased in the spot market. EEQ also said we should capture more market data instead of relying on one broker's input.[64]

We acknowledge that retailers may use different strategies to buy certificates, but our method aims to estimate a proxy for the range of strategies that could be adopted, and it may not reflect some features of a retailer's actual practices. Since daily trade prices from different trade brokers are strongly aligned, we do not consider there is a need to add input from more brokers.[65]

BRIG said that Reliability and Emergency Reserve Trader (RERT) costs[66] should be separated in the cost stack and funded by Treasury.[67] As required by the Electricity Act, we must have regard to the costs of supplying electricity, which include RERT costs.[68] However, since RERT was not triggered in the 12 months before the draft, we have not included any RERT costs.[69] These costs remain a relevant consideration for the final determination.

Other energy costs[70] have decreased compared to last year:

- for small customer tariffs – by 11.7% ($2.11/MWh)
- for large customer tariffs – by 14.9% ($2.60/MWh).

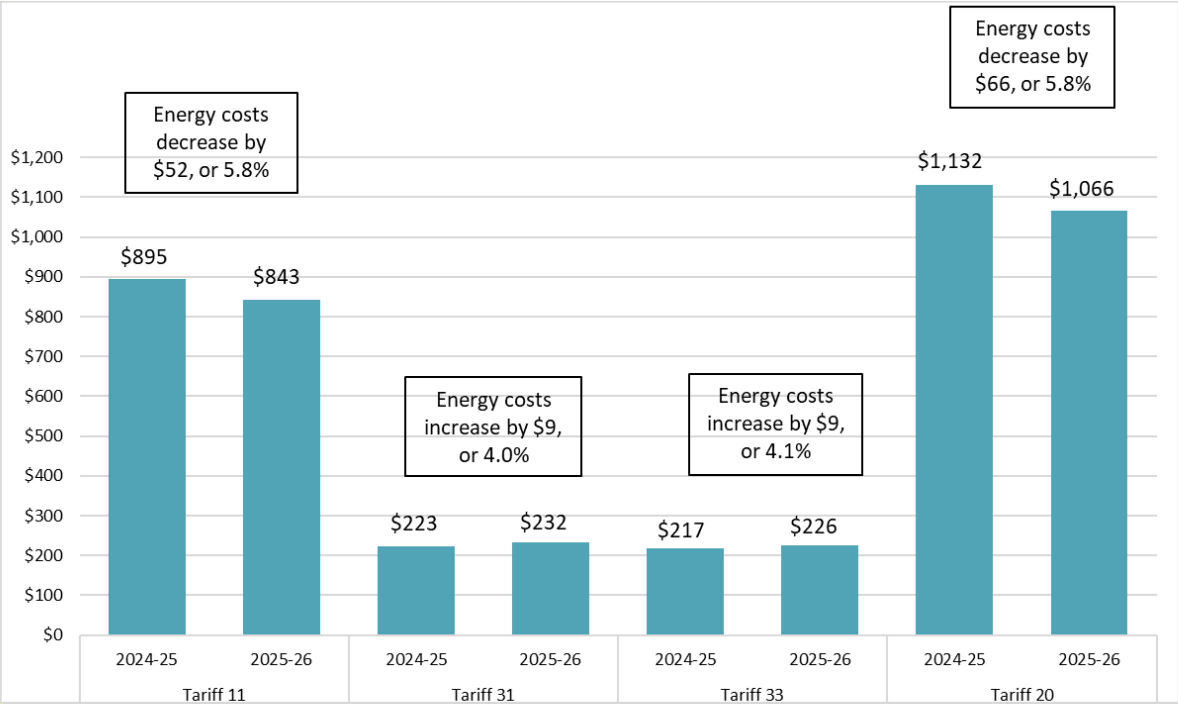
The reasons for these changes are explained in ACIL's report.[71] We will update our estimates for the final determination if new information becomes available.

Total energy costs included in draft notified prices

Overall, energy costs are estimated to decrease for most small and large customers. Figures 4.3 and 4.4 show the total energy costs in draft notified prices compared to last year's estimates, by tariff type for typical small and large customers.

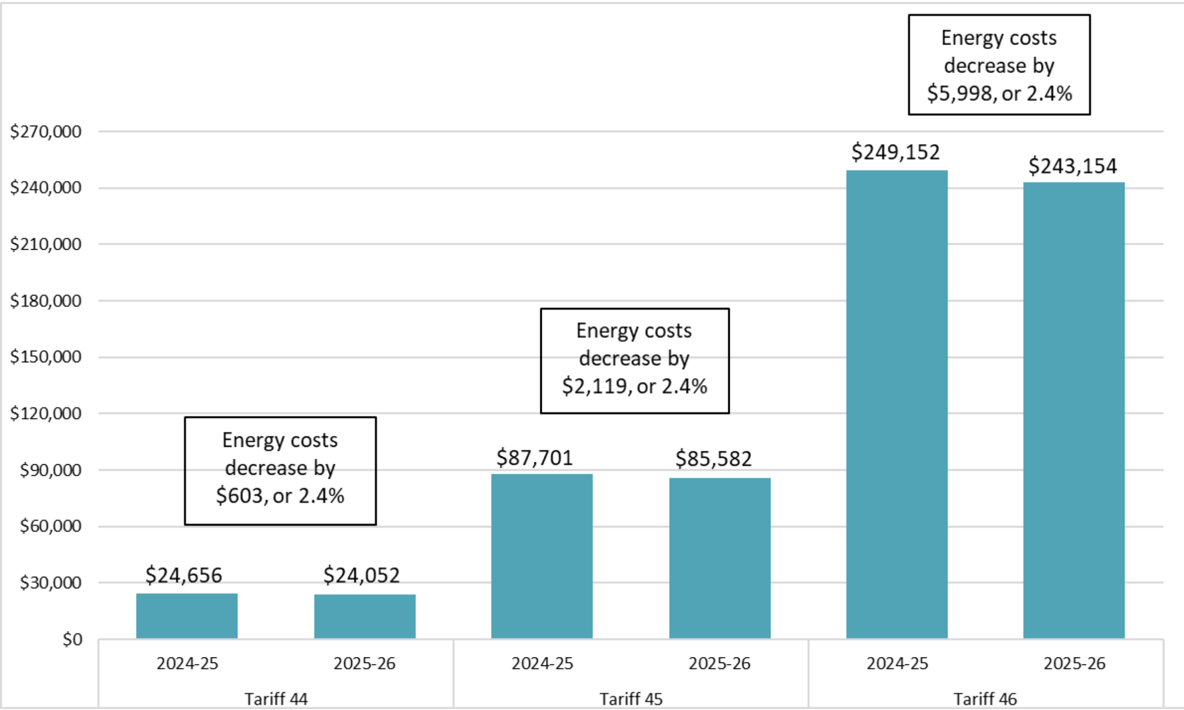
[64] EEQ, sub 4, pp 2–3.
[65] See ACIL's draft report, p 34.
[66] RERT costs are levied by AEMO to maintain power system reliability and security using reserve contracts. The RERT scheme allows AEMO to contract for emergency reserves, such as generation or demand response outside of the NEM.
[67] BRIG, sub 1, p 2.
[68] Electricity Act, s. 90(5)(a)(i).
[69] 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 27, 29.
[70] This excludes costs associated with energy losses and fixed NEM fees.
[71] The changes to each cost category are set out in ACIL's draft report, p 59.

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



Note: As NEM fixed fees are included in energy costs in 2025–26, we have also included these in the 2024–25 energy costs so a like-for-like comparison can be made (last year these costs were included in retail costs for presentational purposes).

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



Note: As NEM fixed fees are included in energy costs in 2025–26, we have also included these in the 2024–25 energy costs so a like-for-like comparison can be made (last year these costs were included in retail costs for presentational purposes).

4.2.2 Retail costs

Retail costs relate to the costs of running a 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 determine retail cost allowances using a well-established benchmark that estimates the costs an efficient retailer would incur, based on market data.[72] Table 4.4 sets out the basis for determining retail cost allowances this year.

Table 4.4: Basis for determining retail cost allowances

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 inflation[b] (to maintain fixed costs in real terms) • maintaining the variable retail cost allocators at: – 7.25% for residential customers – 18.70% 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 allocators at 6.0445%.

a Fixed retail costs were set in our 2021–22 notified price review and have been adjusted for inflation each year since. b We use the RBA's CPI forecast of 3.2% for the financial year ending June 2026. See RBA, *Statement on Monetary Policy*, February 2025.

Retail costs for the new retail tariffs are set in a consistent manner, applying the relevant established fixed retail cost and variable retail cost allocator. Of note, the established fixed retail costs for large customer tariffs were estimated for specific tariffs.[73] Therefore, when determining the relevant fixed costs to apply to the new large customer tariffs, we use existing estimates for the same tariff class.[74] This is consistent with the approach we applied in previous reviews.

EEQ said we should consider cost pressures when setting the retail cost allowances, particularly given some costs have increased beyond inflation in recent years. For instance, administrative costs have increased by more than inflation (such as Australia Post costs, which are exacerbated by the roll-out of advanced digital meters (ADMs) and monthly – as opposed to quarterly – billing). EEQ

[72] 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.
[73] For small customers, the existing fixed retail costs were estimated for residential and small business customers.
[74] For tariff 44A, we use the fixed retail costs estimated for the existing large business demand tariff (tariff 44); for tariffs 49 and 50B, we use the fixed retail costs estimated for existing time-of-use tariffs (tariffs 50 and 50A); for tariffs 52D–52G, we use the fixed retail costs estimated for the existing connection asset customer (CAC) tariffs (tariffs 51A–D and 52A–C).

said we should consider a mechanism to encourage customers to use electronic communication, and it could work with us to develop and implement one that is appropriate. [75]

We acknowledge that the costs of running a retail business evolve over time. Given retail costs were comprehensively reviewed in 2021–22, it may be beneficial to conduct another assessment in a future review. This would allow us to re-evaluate the actual costs of supplying small customers in SEQ, taking into account any potential costs arising due to the roll-out in ADMs, as well as potential savings in retail costs that may have occurred due to productivity improvements.

While we appreciate EEQ's suggestion, we consider EEQ is best positioned to explore and implement initiatives that encourage customers to adopt electronic communication, especially given the potential cost savings that could be realised.

[75] EEQ, sub no. 4, p. 4.

Advanced digital metering service costs – small customers

Retail metering service costs cover:

- the capital and operating expenses associated with customer meters, specifically the ongoing roll-out of ADMs across regional Queensland
- a true-up mechanism to reconcile any under- or over-recovery of metering costs in the previous year.

ADM costs

We have set retail metering service costs for ADMs using a similar approach to last year's notified price review. We use the average cost incurred per ADM in SEQ, applied to the forecast deployment of smart meters in the Ergon Distribution region. This ensures customers in regional Queensland pay no more than customers in SEQ, consistent with the UTP.

However, this year we have not included costs associated with legacy (accumulation) meters as these costs are now (from 2025–26 onwards) included in network prices.[76]

Including a true-up mechanism

This year, we included a true-up mechanism for metering costs to reconcile any over- or under-recovery of metering costs from the previous year.

This process involves:

1. comparing 2024–25 retail metering service costs, based on actual ADM deployment, to the allowance in current notified prices, which is based on forecast ADM deployment[77]
2. taking the under- or over-recovery of metering costs (identified in step 1), and adjusting it for timing differences, to determine the pass-through amount for 2025–26 notified prices.

Based on our assessment, we estimated an under-recovery of retail metering service costs in 2024–25 due to a higher deployment rate (of 56.6%[78]) compared to the forecast rate (55.2%). After adjusting for timing differences, this results in an under-recovery of 0.41c/day to be passed through to notified prices (added to metering costs) in 2025–26.

Retail metering service costs are included in the daily supply charge for small customer primary tariffs. Table 4.5 sets out the basis on which we determined the small customer metering costs.

[76] See AER, *Energex Electricity Distribution Determination 2025 to 2030: Overview*, draft decision, September 2024, p 23.
[77] As the costs are based on mid-year deployment forecasts, we use the actual deployment (as at December 2024) to calculate the actual metering costs used in this comparison. A higher actual mid-year deployment rate means more smart metering costs should have been included in the current metering costs included in 2024–25 notified prices.
[78] Deployment rates are used in conjunction with the SEQ average cost incurred per smart meter to determine ADM costs for regional customers.

Table 4.5: Draft ADM costs for small customer tariffs, 2025–26 (excl GST)

Description	Metering costs (c/day)	Approach
Primary tariff	22.791	To calculate the base metering cost, we used: • relevant ADM metering costs to apply in SEQ, published by the AER[a] • the forecast deployment rate of ADMs for small customers in regional Queensland for 2025–26, as provided by Ergon Retail.
True-up adjustment	0.411	To estimate the under- or over- recovery of metering costs we: • calculated the difference between the retail metering service costs based on a forecast ADM deployment (55.2%) compared to those based on actual ADM deployment (56.6%) • adjusted the difference (under-recovery) in costs for timing differences (by applying the 9.15% weighted average cost of capital).
Overall charge	23.202	Based on the retail metering service costs, with the true-up amount added.

a 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, *Default market offer prices*, draft determination, March 2025.

We intend to use updated ADM cost information in 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 based on Ergon Retail's averaged costs for manually reading type 4A meters, differentiated by customer feeder types (e.g., urban, rural, or isolated) to better reflect the charges that may be incurred for different customer types.

Given the information available, we have set this charge in the same manner as last year – based on the special meter read fee of $67.67 that Ergon Energy has proposed.[79] We intend to update this information based on the AER-approved rate for the final determination.

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.[80]

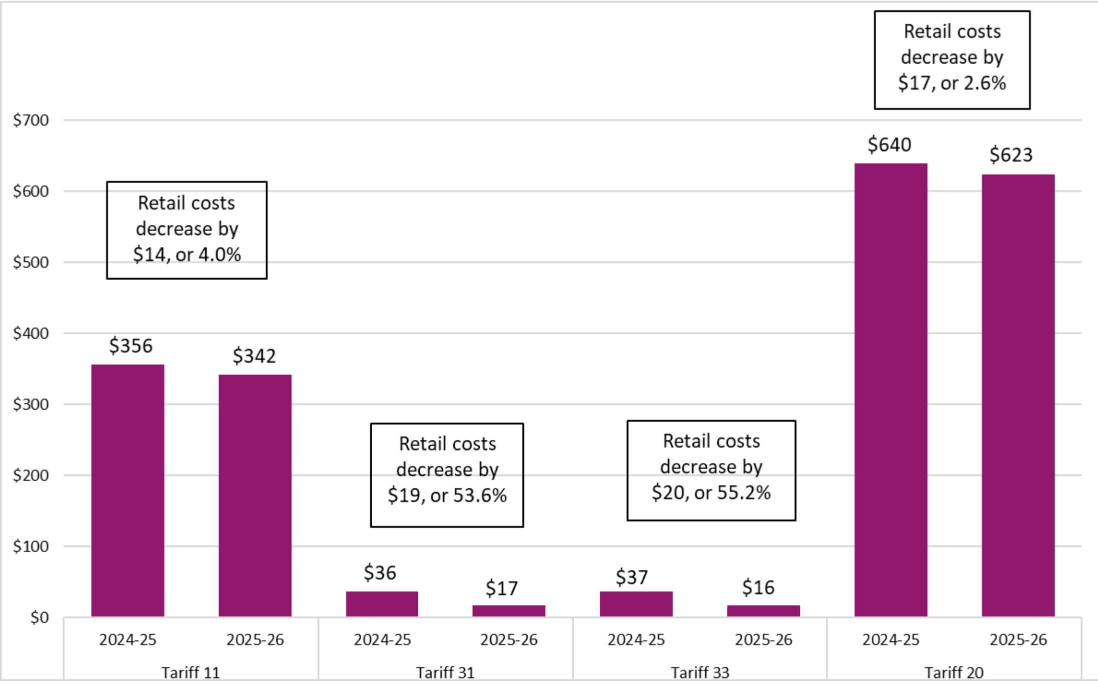
As customers have the option of disabling the communication function of their ADM, this fee can be avoided – we understand this fee applies to very few customers.

[79] Ergon Energy Queensland, *ACS price schedule 2025–30*, November 2024, accessed 25 February 2025.
[80] Ergon Retail has previously advised that information on costs by feeder type is not available.

Retail costs included in draft notified prices

Overall, retail costs have decreased for small customers this year, in part due to the removal of legacy metering costs (which are now included in network prices, discussed above). Retail costs have increased for large customers. The change to the annual bill for a typical customer is set out in Figures 4.5 and 4.6.[81]

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



Note: The NEM fixed fees included in retail costs for 2024–25 have been removed in this figure to provide a like-for-like comparison with 2025–26 retail costs. NEM fixed fees are now accounted for in energy costs.

[81] Amounts presented are rounded. Percentage changes are based on unrounded amounts.

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

Note: The NEM fixed fees included in retail costs for 2024–25 have been removed in this figure to provide a like-for-like comparison with 2025–26 retail costs. NEM fixed fees are now accounted for in energy costs.

5 Other costs and pricing matters

We have considered other costs and pricing matters when setting notified prices, including the standing offer adjustment, the recovery of small-scale renewable energy scheme (SRES) costs, and the default retail tariff arrangements.

5.1 Standing offer adjustment – small customers

The standing offer adjustment (SOA) is a value incorporated into small customer tariffs, intended to reflect the value of more favourable terms and conditions in standard contracts relative to market contracts.[82]

We estimate the SOA using an established method that incorporates market information to assess the costs associated with SEQ market contracts (e.g. fees and charges a customer in SEQ may incur).[83] This market data serves as a proxy for measuring the benefits of standard contract terms and conditions for customers in regional Queensland (e.g. fees and charges they could avoid).

To do this, we used 2023–24 SEQ market data[84] to:

- assess the range of fees and charges linked to retail market contracts in SEQ
- identify any additional fees in retail market contracts compared to standard contracts
- estimate the average additional costs small customers in SEQ on market contracts could incur.[85]

Based on our assessment, small customers in SEQ on market contracts incur, on average, an additional $54.62 in fees. This amounts to around 3.35% of a small customer's annual bill.

As a result, we consider a SOA of 3.35% (of total costs) to be an appropriate value to include in small customer notified prices, subject to the DMO comparison (discussed below). The SOA has decreased slightly from last year's 3.45% due to a reduction in average retailer fees and an increase in typical annual bills for small customers in SEQ.

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[82] The inclusion of the SOA is consistent with the requirements of the ministerial delegation and is a long-standing practice in our price determinations.
[83] The method we use was established as part of the 2021–22 notified prices review.
[84] This data reflects our most recent review of retail fees in SEQ (QCA, *SEQ retail electricity market monitoring 2023–24*, December 2024, pp 40-59).
[85] The typical annual bill for small customers is based on June 2024 data from Appendix A of the QCA's *SEQ retail electricity market monitoring report 2023-24: Appendices*.

DMO comparison

We compare the notified price bills (including the SOA) with the DMO reference bills in SEQ to determine whether to discount the SOA – i.e. when notified price bills (including the SOA) exceed the corresponding DMO reference bills for SEQ. [86]

For the DMO comparison, we followed the same approach as last year, using the updated 2025–26 draft DMO reference bills recently published by the Australian Energy Regulator (AER). [87] Our process included the following steps:

- **adjustments for a like-for-like comparison:**
  - goods and services tax (GST) – as GST is included in the DMO bills but not in our notified prices, we included the GST value in our notified price bills
  - consumption levels – as consumption levels differ for the DMO bills, we used the DMO consumption levels to calculate comparable notified price bills
  - allocation for load control tariffs – the AER uses an apportioning approach to calculate a single DMO bill for tariffs 31 and 33, with an allocation of 29% for tariff 31 and 71% for tariff 33. We applied the same method to calculate a single notified price bill for load control tariffs
- **comparison of notified price bills** (including the 3.35% SOA) with the DMO reference bills for SEQ.

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

As a result, we consider it appropriate to discount the SOA included in small customer notified prices. In line with guidance from the Minister, we propose doing so in a manner that maintains the price relativity of small customer tariffs.

Therefore, for:

- **all residential customer and load control tariffs** – we maintained the SOA at 3.35% (reflecting that tariff 11 was lower than the relevant DMO reference bill)
- **all small business tariffs** – we discounted the SOA from 3.35% to -2.37% (reflecting the reduction required for tariff 20 when compared to the relevant DMO reference bill).

Our approach ensures that price relativity is maintained within each customer class (residential or small business). By maintaining the SOA/applying the same discount to the SOA for all tariffs within a customer class, we prevent any tariffs from becoming more attractive than others, which could distort tariff price signals and influence customer preferences.

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

[86] The AER sets 4 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.
[87] AER, *Default market offer prices*, draft determination, March 2025.

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

Customer type	Relevant notified price tariff	DMO reference bill (A)	Notified price bill, 3.35% SOA (B)	Difference (B - A)	Notified price bill, with adjusted SOA[a] (C)	Difference (C - A)
Residential	11	$2,185	$2,165	($20)	$2,165	($20)
	11+31,33	$2,475	$2,468	($7)	$2,468	($7)
	12B	$2,185	$2,090	($95)	$2,090	($95)
Small business	20	$4,439	$4,699	$260	$4,439	$0

a. No adjustment is required to the SOA for residential tariffs.

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.[88] 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 over-recovery of SRES costs for 2024–25 – the actual SRES liabilities were lower than forecast in last year's final determination (i.e. retailers purchase less certificates to surrender to the CER than initially forecast). [89]

We treat the over-recovery of SRES costs as a cost pass-through in notified prices, which decreases usage charges for all retail tariffs this year. [90,91]

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 2025–26, using confidential data EEQ provided for each large customer type.[92]

[88] The CER typically determines the final SRES liabilities for the second half of the financial year about 9 months after our final determination.
[89] Reflecting the CER's final SRES liabilities for both calendar years 2024 and 2025. See Clean Energy Regulator, Small-scale technology percentage, CER website, 2025, accessed 17 February 2025.
[90] 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.
[91] See Appendix D for further detail on how we determine the SRES cost pass-through.
[92] 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.

The metering charges for large customers are set out in Chapter 6.[93]

5.4 Default retail tariff arrangements

Under the retail tariff schedule, there are default tariff arrangements that apply if a small customer does not nominate a tariff when they become a standard contract customer of a retailer. In this situation, the retailer must assign the customer to tariff 11 (for residential customers) or tariff 20 (for small business customers).[94] Importantly, these default tariff arrangements do not prevent a customer from later requesting assignment to another tariff.[95]

The Minister's delegation requires us to assess whether there is an ongoing need for these default tariff arrangements.[96] Subject to feedback from stakeholders, and in line with our views in last year's determination, we consider there is merit in retaining these default tariff arrangements. The arrangements offer customers certainty regarding the retail tariff they will be assigned if they do not nominate a tariff. This is especially important when a customer is deemed to have entered a standard contract with a retailer.[97]

5.5 Additional issues raised by stakeholders

Stakeholders commented on a range of matters beyond the scope of our review (see Chapter 1), including:

- the consumption threshold used to classify large customers should be increased from 100 to 160 MWh[98]
- businesses that move to a market contract should be able to return to standard contracts with EEQ if market conditions become unfavourable.[99]

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, including the regulatory threshold for large customers and the 'non-reversion' policy for large business customers set in legislation.

In relation to the timing of consultation, some stakeholders said our consultation on the interim consultation paper (ICP) would be more meaningful if conducted outside the summer holiday period.[100] We appreciate that the timing of consultation on the ICP is not ideal. However, the timeframes of our review (including the commencement date) are determined by the Minister's

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[93] Metering charges for large customers are separately identified. This is different to the small customer metering costs, which are captured in the small customer retail tariffs.
[94] 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.
[95] Queensland Government, *Gazette: Extraordinary*, no 29, vol 396, 7 June 2024, tariff schedule, p 225.
[96] Appendix A: Minister's delegation, schedule, cl 2(e).
[97] For example, a deemed customer retail arrangement can apply when a small customer starts consuming energy at a premises without applying to a retailer (i.e. a move-in customer). See ss 54–55 of the *National Energy Retail Law (Queensland)* and div 8 of the National Energy Retail Rules. A customer may be transferred to a designated retailer of last resort if their retailer becomes insolvent or has its authorisation revoked.
[98] QFF, sub 6, p. 3-4; M Gross, sub 5, p. 1; BRIG, sub 1, p. 2.
[99] CPAQ, sub 2, pp 2-3, 6, 11.
[100] EVC, sub 3, p 3.

delegation. The ICP is the first stage of our consultation process, and stakeholders have an opportunity to make further submissions in response to the draft determination.

6 Draft notified prices

Draft notified prices for 2025–26 are set out by customer type in tables 6.1 to 6.11.[101]

Table 6.1: Residential customers (excl GST), 2025–26

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)	150.393	30.856			
Tariff 12B – residential time-of-use[b]	148.016	20.808	27.419	40.880	
Tariff 12C – residential time-of-use[b]	148.016	7.119	25.897	51.541	
Tariff 14A – residential time-of-use demand[c]	126.727	20.808	27.419	23.146	7.759
Tariff 31 – night rate (super economy)	15.502	14.106			
Tariff 33 – controlled supply (economy)	15.502	15.056			

a. Charged per metering point.
b. Peak usage – 4 pm to 9 pm; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 4 pm.
c. Peak usage – 4 pm to 9 pm; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 4 pm. Demand – 4 pm to 9 pm all days.

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

Table 6.2: Small business and unmetered supply customers (excl GST), 2025–26

Retail tariff	Fixed[a]	Usage			Demand
		Off-peak/ flat	Shoulder	Peak	
	(c/day)	(c/kWh)	(c/kWh)	(c/kWh)	($/kW/mth)
Tariff 20 – business (flat-rate)	190.415	33.404			
Tariff 24A – business (time-of-use demand)[b,d]	167.070	29.105			6.109
Tariff 24C – business (time-of-use demand)[c]	181.140	21.755	31.437	23.753	8.112
Tariff 34 – business (interruptible supply)	181.140	24.455			
Tariff 91 – unmetered		31.457			

a. Charged per metering point.
b. Demand – 4 pm to 9 pm on weekdays.
c. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days. Demand – 5 pm to 8 pm weekdays.
d. Tariff to be made obsolete with a 12-month phase out date.

Table 6.3: Small business customers (excl GST), 2025–26

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,c]	167.070	198.419	229.767	261.320	292.769	26.325	38.334	44.679
Tariff 22C – small business time- of-use inclining band[b,c]	167.070	198.419	229.767	261.320	292.769	12.593	38.501	55.825

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.
c. Tariff to be made obsolete with a 12-month phase out date.

Table 6.4: Small business customers (excl GST), 2025–26

Retail tariff	Fixed	Usage		
	(c/day)	Off-peak/flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)
Tariff 22D – small business time-of-use[a]	189.926	21.755	33.014	45.772
Tariff 22E – small business time- of-use[a]	189.926	6.966	31.273	55.712

a. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days.

Table 6.5: Large business and street lighting customers (excl GST), 2025–26

Retail tariff	Fixed	Usage			Demand						Excess demand
		Off-peak/flat	Shoulder	Peak	Off-peak/flat[a]	Shoulder	Peak	Off-peak/flat[a]	Shoulder	Peak	
	(c/day)	(c/kWh)	(c/kWh)	(c/kWh)	($/kW/mth)	($/kW/mth)	($/kW/mth)	($/kVA/mth)	($/kVA/mth)	($/kVA/mth)	($/kVA/mth)
Tariff 44 – over 100 MWh small (demand)[e]	4673.958	18.887			29.421			26.477			
Tariff 44A – over 100 MWh small (demand)	4607.366	19.916						23.060			
Tariff 45 – over 100 MWh medium (demand)[e]	14999.742	18.893			29.144			26.229			
Tariff 46 – over 100 MWh large (demand)[e]	39362.890	18.402			28.537			25.683			
Tariff 49 – large business time-of-use energy[d]	6497.507	17.145	33.263	37.293							
Tariff 50A – large business time-of-use demand[b,e]	19008.100	19.487						18.844			1.953
Tariff 50B – large business time-of-use demand[c]	1891.507	17.145	19.735	17.145		8.343	20.754		9.270	23.060	
Tariff 60A – large business flat-rate interruptible supply (primary)	1935.866	23.813									

Retail tariff	Fixed	Usage			Demand						Excess demand
		Off-peak/flat	Shoulder	Peak	Off-peak/flat[a]	Shoulder	Peak	Off-peak/flat[a]	Shoulder	Peak	
	(c/day)	(c/kWh)	(c/kWh)	(c/kWh)	($/kW/mth)	($/kW/mth)	($/kW/mth)	($/kVA/mth)	($/kVA/mth)	($/kVA/mth)	($/kVA/mth)
Tariff 60B – large business flat-rate interruptible supply (secondary)	1474.900	14.251									
Tariff 71 – street lighting		33.604									

a. Customers on tariffs 44, 45 and 46 will be charged for demand on either a kW or kVA basis, based on their metering arrangements.
b. Demand – 4 pm to 9 pm weekdays.
c. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days. Peak demand – 5 pm to 8 pm weekdays; shoulder (night) demand – all other times; off-peak (day) demand – 11 am to 1 pm all days.
d. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days.
e. Tariff to be made obsolete with a 12-month phase out date.

Table 6.6: Very large business customers (excl GST), 2025-26

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)	23026.224	15.331	8.444	3.849	4.414
Tariff 51B – high voltage (CAC 33 kV)	15065.524	15.331	8.444	4.510	4.565
Tariff 51C – high voltage (CAC 22/11 kV Bus)	13561.224	15.331	8.444	5.068	5.551
Tariff 51D – high voltage (CAC 22/11 kV Line)	12637.824	15.331	8.444	9.431	11.152
Tariff 53 – high voltage (ICC)	22812.687	15.331		3.849	4.414
ICC site-specific – high voltage	2879.787	12.467		0.219	0.252

Table 6.7: Very large business customers (excl GST), 2025-26

Retail tariff	Fixed	Usage		Connection unit	Capacity	Demand			Demand
		Off-peak /flat	Peak			Off-peak	Shoulder	Peak	
	(c/day)	(c/kWh)	(c/kWh)	($/day/unit)	($/kVA of AD/mth)	($/kVA/ mth)	($/kVA/ mth)	($/kVA/ mth)	($/kW/mth)
Tariff 52A – high voltage (CAC STOUD 33-66 kV)[a,c]	11721.172	19.013	13.701	7.861	7.015			17.502	
Tariff 52B – high voltage (CAC STOUD 22/11 kV Bus)[a,c]	11721.172	19.013	13.701	7.861	5.034			55.851	
Tariff 52C – high voltage (CAC STOUD 22/11 kV Line)[a,c]	11721.172	19.013	13.701	7.861	8.996			66.323	
Tariff 52D – high voltage (CAC 66 kV)[b]	52850.024	13.724		8.444			4.262	6.088	2.217
Tariff 52E – high voltage (CAC 33 kV)[b]	24210.624	13.724		8.444			4.262	6.088	2.217
Tariff 52F – high voltage (CAC HV Bus)[b]	18798.424	13.724		8.444			9.409	13.442	2.217
Tariff 52G – high voltage (CAC HV Line)[b]	15476.724	13.724		8.444			13.940	19.914	2.217

a. Peak usage – summer months, off-peak usage – all other times. Chargeable demand is the maximum demand between 10am and 8pm summer weekdays.
b. Peak demand – 5 pm to 8 pm weekdays; shoulder (night) demand – all other times; off-peak (day) demand – 11 am to 1 pm all days.
c. Tariff to be made obsolete with a 12-month phase out date.

Table 6.8: Large business customers (excl GST), 2025-26

Retail tariff	Fixed	Usage[a]	
		Below threshold	Above threshold
	(c/day)	(c/kWh)	(c/kWh)
Tariff 43 – Business customer (over 100 MWh)	4607.366	21.031	18.868

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

Table 6.9: Limited-access obsolete tariffs – small business customers (excl GST), 2025-26

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,d]	147.893	77.667	65.005	24.640		
Tariff 65A – time-of-use tariff[b,d]	147.393	60.869		31.563		
Tariff 66A – dual-rate demand tariff[c,d]	310.493			29.759	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.
d. Existing obsolete tariff with a 12-month phase out date.

Table 6.10: Existing obsolete tariffs – large business customers (excl GST), 2025-26

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)[b]	4155.965	22.712	16.238	12.513	84.881

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).
b. Existing obsolete tariff with a 12-month phase out date.

Table 6.11: Metering charges – large and very large business customers advanced meters (excl GST), 2025–26

Customer type	Metering charge (c/day)
Standard asset customer (annual usage of 750 MWh or less)	216.644
Standard asset customer (annual usage greater than 750 MWh)	260.065
Connection asset customer	428.707
Individually calculated customer	374.767

Source: Retailer data.

Stakeholder submissions and references

Stakeholder submissions

We received 6 submissions on the ICP (available on our website).

Stakeholder	Submission number	Date received
Bundaberg Regional Irrigators Group (BRIG)	1	24 January 2025
Caravan Parks Association of Queensland (CPAQ)	2	24 January 2025
Electric Vehicle Council (EVC)	3	24 January 2025
Ergon Energy Queensland (EEQ)	4	24 January 2025
Gross, M.	5	13 February 2025
Queensland Farmers' Federation (QFF)	6	24 January 2025

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