Queensland Competition Authority

Regulated retail electricity prices in regional Queensland for 2026–27

Final determination

June 2026

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1 About our review

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

On 19 January 2026, 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 2026–27.[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 and our own analysis.

This final determination includes notified prices to apply from 1 July 2026.

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.[2]

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] Electricity Act, s 90(5)(a). We may also have regard to any other matter we consider relevant (s 90(5)(b)).

1.1 Review process

1.1.1 Final determination

This year, electricity bills for residential and small business customers are expected to decrease, including for customers on load control tariffs. While there have been changes in the underlying costs of supplying electricity, these decreases are largely driven by lower default market offers (DMOs) for south-east Queensland (SEQ), which cap notified prices.

Electricity bills for large customers are also expected to decrease, largely due to lower energy costs that have more than offset the increase in network costs.

The notified prices are bundled prices that reflect the retail tariff structure (except for site-specific tariffs).[3] Indicative customer bill impacts are discussed in Chapter 2.

As part of this year's review, we have also considered several new and potential tariff options (see sections 3.1 to 3.3).

1.1.2 Consultation timetable

Key dates for our review are shown in Figure 1.1.

Figure 1.1: Stages of the review

1.1.3 Supporting information

Supporting information available on our website includes:

- the Minister's delegation and terms of reference
- an information booklet that provides an overview of the key issues related to setting notified prices this year
- appendices to this report:
  - Appendix A: SRES cost pass-through approach
  - Appendix B: Data used to estimate customer impacts
  - Appendix C: Build-up of notified prices

[3] As required in cl 8 of the schedule to the Minister's delegation. Bundled prices combine the individual cost components that make up the notified prices.

  - Appendix D: Gazette notice
- reports prepared by our consultant ACIL Allen (ACIL) on:
  - energy costs (see section 4.2.1)
  - retail costs (see section 4.2.2).

1.2 Human Rights Act declaration

While our decision is economic in nature, the *Human Rights Act 2019* (Qld) requires us to consider human rights that may be affected by our determination of notified prices. We consider that our decision does not give rise to a limitation of any right under the Human Rights Act.

2 Indicative customer bills

Overall, residential, small business and large customers can expect to see a decrease in their electricity bills in 2026–27.

For residential and small business customers, the decreases largely reflect lower DMOs for SEQ, which cap notified prices. For large customers, lower energy costs are expected to more than offset increases in network costs.

Importantly, these bill estimates are indicative only. A customer's actual bill will vary depending on a range of factors, including their electricity use, whether they export solar energy, and any rebates or concessions they receive.[4] Customers seeking further information should contact their retailer.

2.1 Small customers

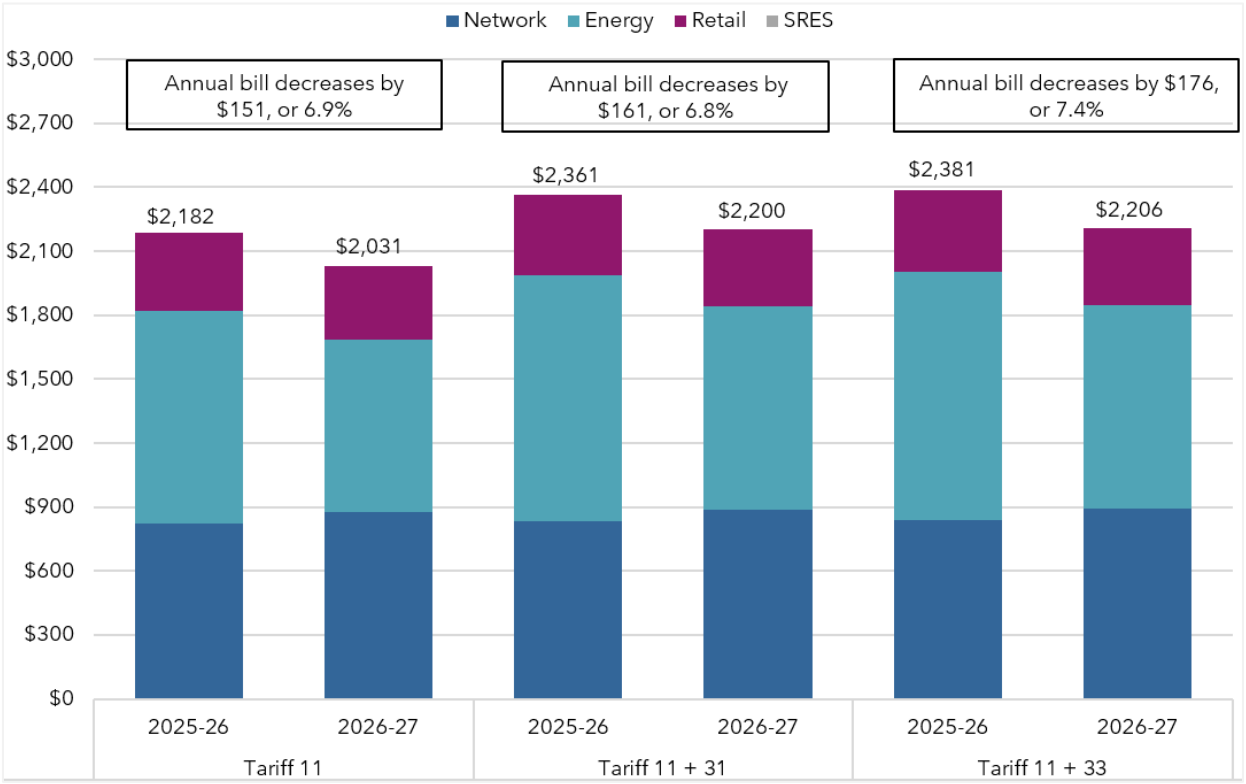
2.1.1 Residential and small business customers

Typical customers on the main residential tariff (tariff 11) are expected to pay around **6.9% less** for electricity in 2026–27 relative to 2025–26 (Figure 2.1). Customers on secondary load control tariffs (tariffs 31 and 33)[5] are also expected to see bill reductions in 2026–27.

Typical customers on the main small business tariff (tariff 20) are expected to pay around **8.1% less** for electricity in 2026–27 relative to 2025–26 (Figure 2.2).

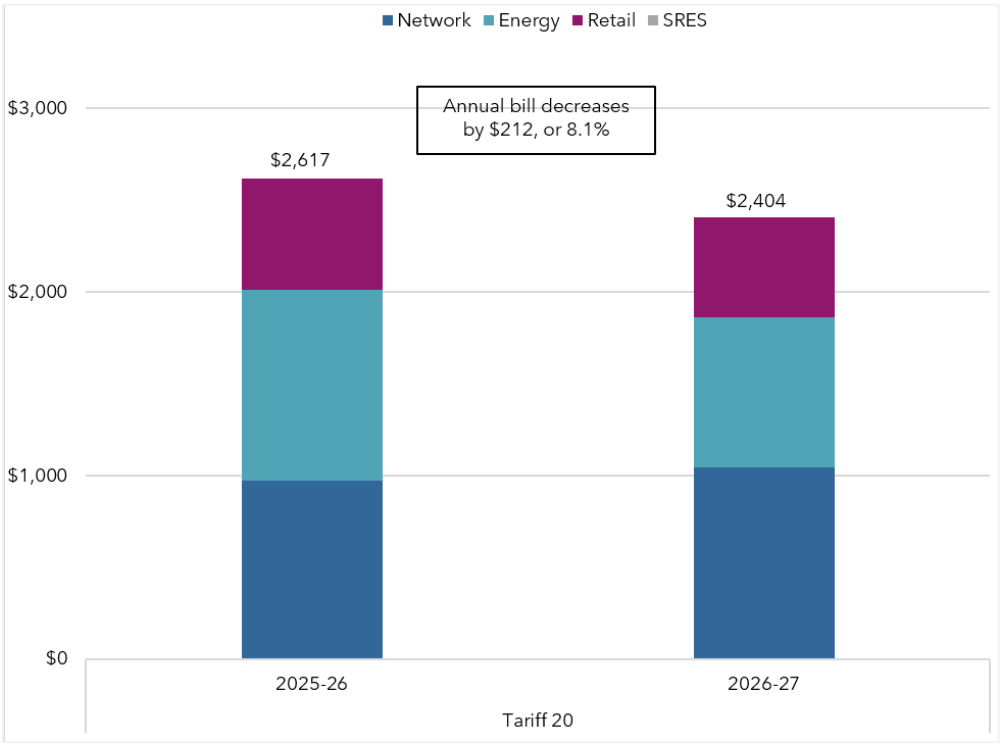
[4] Bills in this determination are based on the consumption of a typical customer – the median customer among all regional Queensland customers on the same tariff (see Appendix B).
[5] Tariffs 31 and 33 have interruptible supply and are often used for appliances such as hot water systems and pool pumps.

Figure 2.1: Residential customer bills, 2025–26 and 2026–27 (incl GST)



Note: 1. Small-scale Renewable Energy Scheme (SRES) costs are too small to be visible in the chart. 2. Bill changes (dollar amounts) are rounded. 3. Percentage changes are calculated using unrounded values.

Figure 2.2: Small business customer bills, 2025–26 and 2026–27 (incl GST)



Note: 1. Small-scale Renewable Energy Scheme (SRES) costs are too small to be visible in the chart. 2. Bill changes (dollar amounts) are rounded. 3. Percentage changes are calculated using unrounded values.

2.1.2 Key drivers of bill changes

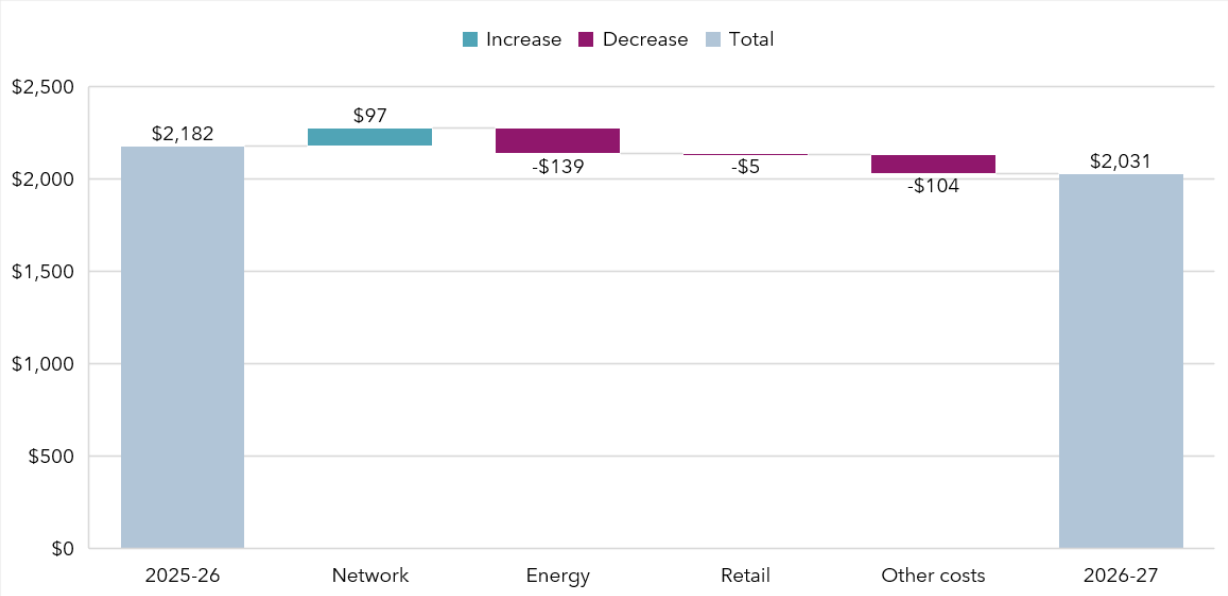
Changes to notified prices reflect changes in the costs retailers incur to supply electricity. This year, while underlying supply costs changed across tariffs, bill impacts for residential and small business customers in regional Queensland are mainly driven by the DMOs for SEQ, which cap notified prices.

The main bill outcomes for key tariffs in 2026–27, and the factors contributing to changes, are outlined below:

- **tariff 11 decreased** (the main residential flat-rate tariff):
  - lower energy costs more than offset higher network costs, reducing the underlying cost of supply by around 2.3%
  - the DMO cap reduced the tariff further, resulting in a larger decrease in the typical customer bill
- **tariff 20 decreased** (the main small business flat-rate tariff):
  - lower energy costs only partially offset higher network and other costs, resulting in an overall increase in the underlying cost of supply by around 6.1%
  - the DMO cap reduced the tariff, resulting in an overall decrease in the typical customer bill
- **tariffs 31 and 33 decreased** (secondary load control tariffs):
  - lower energy costs reduced the underlying cost of supply
  - the DMO cap reduced these tariffs further.

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

Figure 2.3: Tariff 11 bill – changes in cost components, 2025-26 to 2026-27 (incl GST)

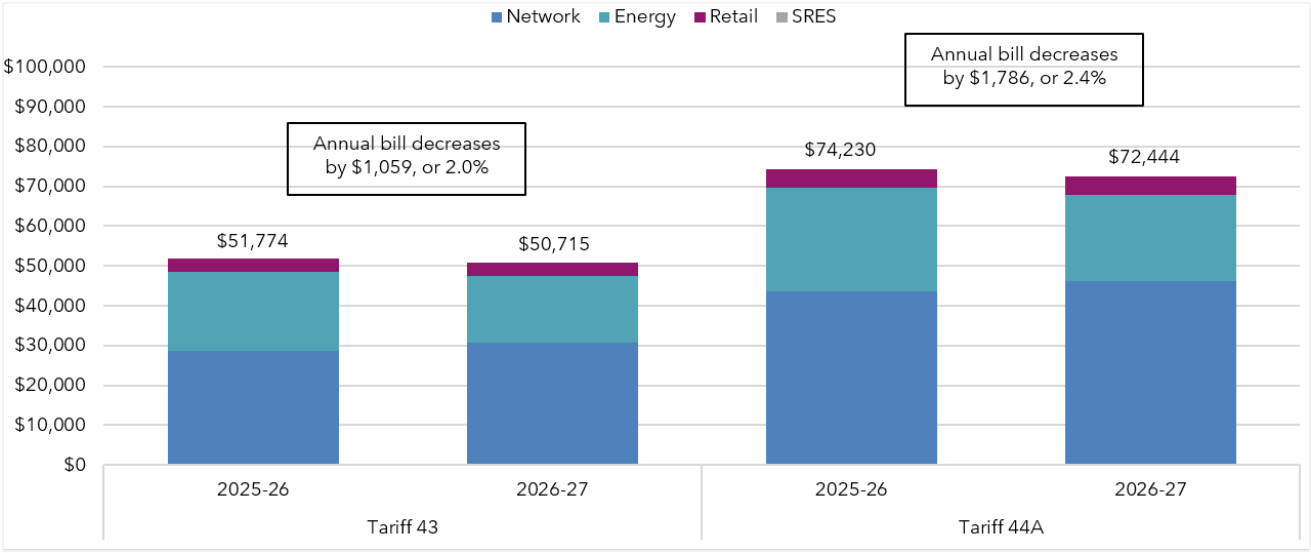


Note: 1. Other costs include SRES and the standing offer adjustment (SOA). 2. The SOA is negative this year, largely due to the DMO cap (see section 5.1) and drives the decrease in other costs compared with last year.

2.2 Large customers

Typical large customers on tariffs 43 and 44A are expected to pay around **2.0% and 2.4% less**, respectively, for electricity in 2026–27 relative to 2025–26 (Figure 2.4). These decreases are mainly driven by a decrease in energy costs that more than offsets increases in network costs.[6]

Figure 2.4: Comparison of large business customer bills for 2025–26 and 2026–27 (incl GST)



Note: 1. Small-scale Renewable Energy Scheme (SRES) costs are too small to be visible in the chart. 2. Bill changes (dollar amounts) are rounded. 3. Percentage changes are calculated using unrounded values.

[6] Large customer tariffs have a higher share of network costs (around 60–65% of total costs) than small customer tariffs (around 45–50%), meaning changes in network costs generally have a larger impact on large customer bills. More broadly, all customers benefited from lower energy costs this year due to the higher availability of Queensland coal generators, lower gas prices and increased renewable generation.

3 Overarching framework

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

The framework for setting notified prices reflects the relevant provisions 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 AER's DMOs in SEQ to cap notified prices for small customers (see section 5.1)
- the network plus retail (N+R) cost build-up methodology – under this methodology, we treat the N component (network costs) as a pass-through and determine 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 our long-standing practice in price determinations.

Table 3.1: Overarching framework matters

Matter	Effect
Queensland Government's UTP	This means generally basing notified prices on: • for small customers (residential and small business customers) – the cost of supplying small customers in SEQ • for large customers – the costs of supplying large customers in Ergon Energy Network's (EEN's) east distribution pricing zone, 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 AER (i.e. passing through the N component) • adding our estimate of energy and retail costs (i.e. the R component).

Several stakeholders raised affordability as a key concern. Industry and agricultural stakeholders said electricity prices materially affect operating costs and industry viability, particularly following cumulative increases over several years.[7] CPAQ similarly noted that electricity is one of the largest operating expenses for caravan and residential parks, with rising costs affecting investment decisions and regional competitiveness.[8]

[7] QCAR, sub 8, pp 3–4; Cotton Australia, sub 3, p 6; QFF, sub 12, pp 2–3, sub 22, p 3.
[8] CPAQ, sub 2, p 1.

QCOSS referred to our SEQ market monitoring report, noting 91% of customers in the Energex area are on cheaper market offers, so Ergon customers paying notified prices generally face higher costs. QCOSS said notified prices should be set so that they are no higher than those market offers to be consistent with the UTP.[9]

We acknowledge concerns about electricity prices and affordability. In setting notified prices, we have had regard to the matters specified in the Electricity Act and the Minister's delegation, including the costs of supplying electricity. The Queensland Government's UTP is the primary mechanism through which the government addresses electricity affordability for customers in regional Queensland and determines the level of price support provided to customers. By applying the UTP when setting prices, notified prices are generally set below the actual cost of supply in regional Queensland, with the difference funded by the Queensland Government through a community service obligation (CSO) payment. The CSO payment was estimated at approximately $604 million in 2025–26.[10] This reflects a policy decision by the Queensland Government to support regional customers.

For small customers, the delegation requires us to continue applying the established pricing framework (i.e. the UTP and N+R framework). While QCOSS interpreted the broader UTP objective as requiring prices to reflect those paid by customers on market offers in SEQ, we do not consider this interpretation is supported by the delegation. Rather, the delegation specifies how particular cost components are to be determined with reference to SEQ (such as network costs), while the Minister's letter provides further guidance that the DMO should be used as the relevant cap for small customer notified prices.

We also do not consider current market offers provide a sufficiently reliable basis for setting regulated prices under the current pricing framework. As discussed in our assessment of retail costs and in the explanation of our decision to retain the existing retail cost benchmark (see section 4.2.2), we do not consider that current competitive offers in SEQ are a reliable reflection of the prices customers actually pay, the efficient costs of supply, or a stable recovery of underlying costs. Rather, we expect they may reflect retailer acquisition strategies and positioning relative to the DMO.

Accordingly, while some SEQ customers may currently be on market offers below the DMO, we consider it reasonable and appropriate to continue using the DMO as the relevant cap for small customer notified prices, consistent with the Minister's delegation and the established pricing framework.

Stakeholders also raised concerns regarding tariff structures, including:

- their suitability for agricultural businesses
- the level of daily supply charges (particularly for tariff 49) and demand charge components
- the restricted availability of volumetric-based tariffs to large business customers
- the alignment of time-of-use (TOU) windows with periods of solar generation and flexible load operation.[11]

Under the N+R framework, we pass through network tariff structures approved by the AER, including fixed charges, time-of-use windows, demand charge components and tariff eligibility conditions, unless the Minster directs us to consider new or modified retail tariffs to meet broader policy objectives. Our discretion to alter those structures is therefore limited. While we acknowledge the importance of the issues raised by stakeholders, broader reform to tariff structures and the

[9] QCOSS, sub 10, Etrog report, p 7, sub 21, Etrog report, pp 10–11.
[10] Queensland Government, *Budget Strategy and Outlook* , Paper 2, Queensland Budget 2025–26, June 2025, p 153.
[11] Hardwick, sub 6, p 1; Cotton Australia, sub 17, pp 6–7; Canegrowers, sub 1, pp 3–4; sub 16, p 1; CPAQ, sub 2, pp 3–4; QFF, sub 12, pp 2–3, sub 22, pp 2–3; Horan & Bird Solar, sub 13, p 4.

introduction of additional support measures fall outside the scope of this price determination. Customers experiencing financial hardship are encouraged to contact their retailer to discuss available assistance options. Key support measures are outlined in Box 2.

EEQ said the following tariffs should be extinguished from 30 June 2026 to remove unnecessary complexity:

- the 'base' TOU tariff for tariffs that have a solar soaker variant (e.g. tariffs 12D, 22D and 50B) due to identical tariff structures and materially lower customer numbers than the solar soaker variants
- tariff 49, due to the high fixed charge that makes customer uptake unlikely.[12]

We have decided at this stage not to extinguish these tariffs, which are based on approved network tariffs and were introduced in accordance with the N+R framework. However, we could reconsider this matter in a future determination, particularly at the request of the Minister.

[12] EEQ, sub 18, p 4.

Box 2: Customer support measures

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

Retailer hardship obligations

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 provides support to eligible customers experiencing financial hardship, including by offering payment plans.

Government concessions and assistance programs

A range of Queensland Government initiatives are available to eligible households and businesses, including:

- electricity rebates for eligible pensioners and seniors
- the Home Energy Emergency Assistance Scheme, which provides one-off emergency assistance to households experiencing difficulty paying their electricity bills due to an unforeseen emergency or short-term financial crisis in the previous 12 months
- the Drought Relief from Electricity Charges Scheme, which provides drought-declared farming businesses with relief from supply charges on electricity accounts used to pump water for farm or irrigation purposes.
- the ecoBiz program, which assists small to medium-sized businesses reduce energy costs through benchmarking, action planning and on-site coaching. Further information on energy concessions and support for businesses can be found on the Queensland Government's website.

Additional resources

Stakeholders may also refer to:

- Queensland Farmers' Federation's website for information and resources on electricity prices, understanding bills, government schemes and industry specific programs
- Ergon Energy Retail's website for information to assist households, businesses and farmers, including tariff options and support programs.
- The Australian Government's energy.gov.au website for information on how to improve energy efficiency (for households and small businesses) and access rebates across 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 Potential new retail tariffs for 2026–27

3.1.1 Large customer 'solar soaker' tariff

The delegation asks us to consider creating a new 'solar soaker' TOU tariff for large customers.

A solar soaker tariff is based on an existing network tariff and incorporates time-varying wholesale energy costs to create stronger price differences between peak and non-peak periods. This can encourage customers to shift electricity use into non-peak periods to take advantage of lower usage charges. In recent years, solar soaker TOU tariffs have been available for residential customers (tariff 12E) and small business customers (tariff 22E).[13]

We have identified two potential tariff structures that could form the basis of the new solar soaker tariff:

- tariff 49, which has TOU usage charges and a daily supply charge but is limited to customers with monthly peak demand greater than 120 kVA and annual consumption below 160 MWh
- tariff 50B, which includes TOU usage charges, TOU demand charges and a daily supply charge.

Stakeholder comments

Stakeholders generally supported introducing a large customer solar soaker tariff, provided it was structured appropriately, and they generally preferred tariff 50B over tariff 49:

- Cotton Australia said the 'solar soaker' period should reflect genuine periods of solar abundance, like the off-peak period for the residential TOU tariffs, and queried why business TOU tariffs have a shorter off-peak period. Cotton Australia did not support using tariff 49 because of its high daily supply charge and eligibility conditions relating to minimum demand and maximum consumption. While Cotton Australia expressed 'reluctant' acceptance of using tariff 50B as the basis for the solar soaker tariff, it considered the shorter off-peak period was unlikely to drive significant customer change.[14]
- QFF considered tariff 49 unlikely to be effective as a solar soaker tariff due to its prohibitively large daily supply charge and eligibility conditions that limit customer access. QFF supported using tariff 50B in the absence of a more suitable option with a longer off-peak TOU period.[15]
- EEQ supported using tariff 50B as the basis for the solar soaker tariff.[16]

Decision

Some stakeholders proposed that the solar soaker tariff should have a different structure or different terms and conditions than the underlying network tariff. However, under the N+R framework, retail tariffs reflect the structure and terms of the relevant network tariff unless the Minister directs us to consider deviations based on stated policy objectives.

The purpose of introducing a solar soaker tariff is to provide an alternative TOU option with stronger pricing signals, achieved by varying the wholesale energy costs across TOU periods. It is not intended to modify the underlying network tariff structure.

[13] Section 4.2.1 explains how we determine time-varying wholesale energy costs.
[14] Cotton Australia, sub 3, p 4, sub 17, pp 5–6.
[15] QFF, sub 22, p 5.
[16] EEQ, sub 18, p 4.

Accordingly, the solar soaker tariff must be based on an existing network tariff. Therefore, we cannot:

- introduce TOU windows that differ from those in the relevant network tariff, even if doing so would make the tariff more attractive to customers. These windows were developed by Queensland's distribution businesses as part of their network tariff strategies and were approved by the AER. The different TOU periods applying across customer groups reflect decisions made by the network businesses based on their network circumstances and informed by stakeholder feedback at the time[17]
- modify network pricing structures and charges. For instance, stakeholders identified the relatively high daily supply charge for tariff 49 as a barrier to using this tariff as the basis for a solar soaker tariff. However, this charge reflects approved network charges, which retailers must pay, and therefore it must be reflected in the retail tariff (both in terms of tariff 49 and any solar soaker tariff derived from tariff 49).

We have decided to base the new solar soaker tariff on the underlying network tariff for tariff 50B. The new tariff will be designated tariff 50C. While tariff 50B is more complex than tariff 49 because it includes demand charges, large customers are generally familiar with demand-based charging structures.[18,19] In addition, tariff 50B does not include the demand and consumption eligibility requirements that apply to tariff 49. As a result, the solar soaker tariff will be available to a broader range of large customers.

In making this decision, we also had regard to stakeholder views about the unattractiveness of tariff 49, particularly due to its high daily supply charge.

We note the fixed charge for tariff 50B noticeably increased between the draft network prices provided to us by EEN (which we used in our draft determination) and the final 2026–27 network prices approved by the AER (which we have used in this final determination). EEN advised this reflected further tariff rebalancing during the finalisation of pricing outcomes (including decreasing network shoulder usage charges) to produce more consistent customer outcomes across SAC Large tariffs while maintaining cost-reflective pricing principles.

3.1.2 Electric vehicle (EV) tariff proposal

The delegation includes a new process, which is for EEQ to submit an EV tariff proposal that we must assess; we must then decide whether to approve (and publish) the proposal as part of the final determination.

In making this assessment, we must have regard to the matters set out in the Electricity Act[20] and the delegation. The Minister has advised that the proposed EV tariff does not need to satisfy the N+R framework that applies to other retail tariffs. Instead, our assessment must consider:

- if the EV tariff can be offered under a standard retail contract
- the tariff rates that should apply based on what could reasonably be offered by a retailer in the SEQ electricity market.

[17] AER, *Ergon Energy and Energex Electricity Distribution Determinations 2025 to 2030 (1 July 2025 to 30 June 2030); attachment 19: Tariff structure statement*, draft decision, September 2024, pp 13–14.
[18] We note that in accordance with the relevant network tariff structure, demand charges will not be payable for usage within the off-peak period.
[19] Time-varying wholesale energy costs will apply only to the TOU usage charges. They will not apply to the TOU demand charges, which primarily reflect network charges.
[20] These matters are set out in Box 1, Chapter 1.

The delegation also requires that EEQ's tariff proposal include a commitment that consultation on any potential CSO implications has occurred with Queensland Treasury.

Outline of EEQ's proposal

On 23 February 2026, EEQ submitted its EV tariff proposal. EEQ described the proposal as being similar to a load control tariff, but with greater customer autonomy and a simpler technology pathway that does not require dedicated wiring or traditional load control infrastructure.[21]

Tariff design

EEQ proposed an EV tariff that would operate as a TOU tariff and provide a discounted usage charge in the form of a bill adjustment for electricity used during eligible EV scheduled charging sessions.

The TOU windows would be the same as those for other standard residential TOU tariffs,[22] with rates for EV scheduled charging sessions as follows:

- **peak:** charged at the customer's primary tariff rate
- **shoulder:** charged at a discounted 'EV charging usage rate'
- **off-peak:** charged at the same discounted 'EV charging usage rate' as the shoulder period.

EEQ did not propose a tariff rate but recommended that the EV charging rate be no more than tariff 31 (a small customer load control tariff) and be otherwise aligned with comparable offers available in the SEQ market.

All electricity usage would continue to be billed under the customer's primary tariff (such as tariff 11 or another TOU tariff). However, energy consumed during eligible EV scheduled charging sessions would receive a credit on the customer's bill equal to the difference between the primary tariff usage rate and the EV usage rate (where the EV rate is lower).

Customer eligibility and participation

The tariff would be available only to residential customers on an opt-in basis (i.e. not mandatory for customers with EVs) and is proposed to commence from 1 November 2026.

Eligible customers would be required to:

- have a type 4 meter with remote communications enabled
- have compatible charging equipment or systems capable of communicating with the retailer
- maintain that communication capability.[23]

EEQ advised that customers could opt into the tariff through existing channels (such as a phone or MyAccount). However, it indicated that use of the app would be a core enabler of full tariff functionality, including device enrolment, charging preferences and access to charging information.

Technology and billing arrangements

Customers would access the tariff through EEQ's systems for scheduled charging. We understand that the tariff would operate as a device-level EV charging product supported by EEQ's existing systems, including its Kraken retail platform.

[21] See EEQ's *EV tariff proposal* (pp 2–4) on our website.
[22] Peak: 4–9 pm; day (off-peak): 11 am – 4 pm; night (shoulder): all other times.
[23] EEQ EV tariff proposal, pp 3-4.

Total consumption for premises would continue to be measured by the customer's existing electricity meter. However, EV charging usage would be determined using information communicated through EV or charger functionality via Kraken.[24]

EEQ's design relies on integration between customer-owned devices, retailer systems and home Wi-Fi connectivity.

Other information provided by EEQ

EEQ confirmed consultation with Queensland Treasury on potential CSO impacts had occurred.[25]

Following EEQ's initial proposal, we requested that EEQ provide a specific rate and further information regarding comparable SEQ products, the operational arrangements supporting the tariff and how the proposed arrangements align with relevant laws and regulations, including the standard retail contract.

In response, EEQ identified Origin Energy's EV Power Up offering as the closest comparable product in terms of underlying technology platform and device-level integration but noted differences in incentives that reflect Origin's use of a market retail contract.[26]

Stakeholder comments

There were mixed views from stakeholders on EEQ's proposed EV tariff. Stakeholders raised comments regarding:

- support for the tariff and broader application – some stakeholders supported introducing an EV tariff in regional Queensland and considered it likely to be well supported by customers.[27] However, others considered the concept should extend beyond EV charging and residential customers to broader flexible loads[28]
- consumer protections and accessibility – QCOSS supported the introduction of an optional EV tariff subject to adequate consumer protections and said that a full consultation process with consumers and EV drivers should occur before any tariff is approved. It also raised concerns about the required use of an app, including internet access limitations in regional and rural areas and the increasing number of apps EV users already need to access charging infrastructure[29]
- pricing and tariff design – QCOSS noted that EEQ had not proposed a tariff rate and considered any rate should align with equivalent offers in SEQ. Horan & Bird Solar recommended demand response mechanisms, including dynamic pricing signals and incentives, to improve the effectiveness of the tariff.[30]

Decision

Our task is to decide whether to approve EEQ's proposed EV tariff having regard to the relevant decision-making matters in the Electricity Act and the requirements of the delegation. While we considered stakeholder views and additional information provided by EEQ, our role is to assess the proposal put forward by EEQ rather than redesign or develop an alternative tariff structure. We also note that the delegation specifically contemplates a residential EV tariff.

[24] EEQ EV tariff proposal, pp 3-4, sub 18, p 3.
[25] EEQ, sub 18, p 3.
[26] Advice from EEQ, received 9 March 2026.
[27] QCOSS, sub 3, p 3, Etrog report, pp 4–5; Horan & Bird Solar, sub 13, p 1.
[28] QFF, sub 22, pp 5–6; Cotton Australia, sub 17, p 5; Canegrowers, sub 16, p 1.
[29] QCOSS, sub 21, p 3, Etrog report, pp 4–5.
[30] Horan & Bird Solar, sub 13, p 1.

Based on the information available, we are not approving EEQ's proposed EV tariff. While the proposal represents an innovative approach to supporting EV charging and customer energy resources, we are not satisfied there is sufficient certainty regarding how the tariff would operate within the existing notified prices and regulatory framework, in particular:

- the absence of a proposed tariff rate, limiting our ability to assess the proposal against the delegation criteria
- whether the proposed operational arrangements and participation conditions sit comfortably within the notified prices framework and standard retail contract arrangements
- regarding billing arrangements and whether existing consumer protections and dispute resolution processes would operate appropriately under the proposed design
- broader operational dependencies required to support implementation.

In undertaking this assessment, we considered not only whether aspects of the proposal may be capable of operating in theory, but also whether there is sufficient certainty regarding how the proposal would operate in practice. This is particularly relevant where new technology arrangements, participation requirements and operational processes would play a central role in determining tariff outcomes.

Regulated EV tariff rate

We are not satisfied there is sufficient information to determine an appropriate pricing outcome for the proposed EV tariff. While the delegation ultimately requires us to decide whether to approve the tariff and determine any approved rate, we consider the new EV tariff process is intended to operate as a proposal and assessment model, whereby EEQ proposes a tariff for consideration, and we assess that proposal against the relevant statutory and delegation criteria. In our view, this does not contemplate core elements of the proposal, including the tariff rate itself, remaining unresolved.

EEQ did not propose a specific tariff rate but instead identified comparable EV products in SEQ and indicated that we could determine an appropriate rate or alternatively adopt tariff 31 as a trial price which could be refined over time.[31] While these inputs provide useful context, they do not include a proposed pricing methodology or supporting analysis explaining why a particular rate would be appropriate. For instance, the comparable EV products EEQ identified operate under different commercial arrangements and broader service offerings, including technology platforms, participation requirements and market-based incentives. This creates challenges in identifying an appropriate comparator and assessing whether a particular tariff rate would reasonably reflect what could be offered in SEQ.

Determining an appropriate regulated tariff rate is not a mechanical exercise where products differ materially in both pricing structures and broader service characteristics. This is particularly relevant given our obligation to have regard to the effect of the price determination on competition in the Queensland retail electricity market. In the absence of a proposed rate and supporting analysis from EEQ, we are not satisfied there is sufficient information to determine an appropriate pricing outcome. An inappropriate pricing outcome could have unintended implications for competition and future incentives for retailers to develop EV products in regional Queensland.

Standard retail contract considerations

More broadly, a key issue in our assessment was whether the proposal remains sufficiently defined by the notified prices and standard retail contract framework, or whether its operation is

[31] EEQ, sub 18, p 3.

substantially determined by retailer systems, technology participation requirements and operational arrangements outside the tariff itself.

Traditional controlled load tariffs generally rely on physical infrastructure and independently verifiable metering arrangements to manage flexible loads. By contrast, the proposed EV tariff relies on software, device integration and retailer-operated systems to identify eligible charging sessions and determine billing outcomes.

The proposal also relies on several participation requirements beyond the tariff itself, including complying with technical and operational requirements set by the retailer, use of compatible equipment and devices capable of communication with retailer systems, customer registration and device enrolment arrangements, and use of retailer technology platforms for scheduled charging. While EEQ considered these arrangements analogous to existing tariff access conditions, we are not satisfied there is sufficient clarity regarding the extent to which customers may need to engage with additional technology platforms, applications and associated participation conditions that extend beyond what is ordinarily contemplated under a standard retail contract.

We also have concerns regarding billing and consumer protections. While total household consumption would continue to be measured through the customer's electricity meter, billing outcomes for EV charging would rely on information communicated through EV devices and retailer systems. This creates uncertainty regarding how existing consumer protections and dispute resolution arrangements would operate where issues arise with telemetry, communications or system connectivity.

We note that comparable products identified by EEQ are generally offered through market retail contracts that include additional operational terms and participation conditions. By contrast, the proposed tariff seeks to deliver a similar product through a standard retail contract arrangement. In our view, there remains insufficient certainty regarding how these arrangements would operate in practice within the notified prices framework.

Other options available

We recognise the broader policy objective of supporting EV uptake and innovation in retail tariff design. We also recognise that retail products and customer energy services are continuing to evolve in response to technological developments and changing customer preferences.

If the Queensland Government wishes to facilitate products of this nature, we note the legislative framework provides mechanisms that may support more tailored retail arrangements outside the standard retail contract framework.[32] Such mechanisms may provide a more suitable pathway for products involving additional operational requirements, participation conditions and technology arrangements, while allowing detailed terms, obligations and consumer protections to be prescribed.[33]

We also consider the proposal would benefit from more extensive consultation with customers and relevant stakeholders to further develop and test the operational aspects of the design before broader implementation. This would provide an opportunity to better understand customer experience, technology requirements and participation arrangements, and assist EEQ in developing an appropriate tariff structure, pricing approach and implementation model.

[32] *National Energy Retail Law (Queensland)*, s 19C(5).
[33] *National Energy Retail Law (Queensland) Bill 2014*, explanatory notes, p 30.

3.1.3 Dynamic flex storage tariffs

In last year's review, we updated regulated retail tariffs to reflect the new network tariffs approved by the AER from 1 July 2025. This resulted in the phasing out of several existing retail tariffs and the introduction of new retail tariffs based on new network tariff structures.

However, we did not introduce retail tariffs based on the new dynamic flex storage network tariffs for large customers and connection asset customers (CAC) (see Box 4). This was due to time constraints and uncertainty regarding the potential use of these tariffs at the time of our determination.[34]

Box 4: Dynamic flex storage tariffs

Dynamic flex storage tariffs apply to importing electricity for the sole purpose of exporting it back to the network. Each tariff includes TOU usage charges (with only usage during the peak period subject to network charges) and a daily supply charge.

Under the network tariff arrangements, customers must have a dynamic connection agreement[35] with the distributor to be eligible for these tariffs. Customers with storage connected to solar photovoltaic (PV) systems, or with additional load behind the same connection point, are not eligible.[36]

Importantly, these tariffs apply only to charges for imported electricity and do not include prices for exported electricity.

Decision

We do not propose to introduce retail tariffs based on the dynamic flex storage network tariffs at this stage.

Under the N+R framework, we would typically introduce a retail tariff that reflects an approved network tariff. However, the dynamic flex storage tariffs are a new and highly specialised tariff type, intended for a specific and limited use rather than for general customer application.

We therefore considered whether there is likely to be sufficient demand for these tariffs in 2026–27 to justify introducing a corresponding retail tariff. Stakeholders did not provide submissions on this matter, and we are not aware of any current demand for this type of tariff.

Without evidence of likely uptake, introducing these tariffs would create administrative costs and implementation burdens for retailers with little or no expected benefit to customers. If demand for these tariffs emerges in the future, we can reconsider introducing them in a future determination.

[34] QCA, *Regulated retail electricity prices 2025–26*, final determination, June 2025, p 14.
[35] EEN, *Explanatory statement: Revised Regulatory Proposal 2025–30*, November 2024, p 45.
[36] EEN, *Tariff Structure Statement: Regulatory Determination Proposal 2025–30*, November 2024, as amended and approved by the AER, April 2025, pp 25–26.

3.2 Tariffs for future consideration

3.2.1 Solar sharer offer

In March 2026, the Australian Government amended the DMO regulations to establish, among other things, a solar sharer offer (SSO) for standing offer customers as part of the AER's DMO process.[37] This followed the publication of the Australian Government's SSO consultation outcome paper in January 2026, which outlined its proposed approach to the design and implementation of the SSO retail product.[38]

The SSO is a residential TOU tariff that provides customers with a zero-cost electricity period (or free usage period) for 3 hours during the day, up to a reasonable use cap. The tariff is designed to align with periods of high rooftop solar generation and low wholesale and network costs. The SSO will be available from 1 July 2026 in DMO regions (New South Wales, South Australia and SEQ).

The Minister asked us to consult with stakeholders on the suitability of establishing a regulated zero-cost electricity period tariff for residential customers in regional Queensland.

Stakeholder comments

Most stakeholders generally supported introducing a solar sharer tariff in regional Queensland. However, stakeholders raised concerns regarding its design, implementation and distributional impacts.

EEQ, QCOSS and Horan & Bird Solar considered regional Queensland customers should have access to a solar sharer tariff in 2026–27, given the SSO will be available in SEQ from 1 July 2026.[39] QCOSS considered it would contradict the UTP for a solar sharer tariff to be available in SEQ but not in regional Queensland.[40]

EEQ said a solar sharer tariff should only be available to residential customers, consistent with the SSO in SEQ, and we should publish clear and accessible customer information explaining how the tariff operates.[41] Similarly, QCOSS and the Queensland Consumers' Association emphasised the importance of customer education and measures to assist customers understand their tariff options and make well-informed decisions.[42]

Retailers said any solar sharer tariff would need to ensure full recovery of electricity supply costs:

- EEQ stated that wholesale, AEMO, environmental and network costs incurred during the free usage period would still need to be recovered.[43]
- Origin did not support a regulated zero-cost electricity period tariff, noting that electricity is not costless at any time of day and retailers must recover wholesale, network and operating costs to ensure market stability and efficient pricing signals. Origin also noted that products marketed as 'free energy' typically recover costs through higher charges in other periods or through usage limits.[44]

[37] Competition and Consumer (Industry Code—Electricity Retail) Amendment Regulations 2026.
[38] Australian Government, Department of Climate Change, Energy, the Environment and Water, *Solar Sharer Offer consultation outcomes paper*, January 2026.
[39] EEQ, sub 18, pp 3–4; QCOSS, sub 21, Etrog, p 3; Horan & Bird Solar, sub 13, p 2.
[40] QCOSS, sub 21, Etrog report, p 3.
[41] EEQ, sub 4, p 2, sub 18, p 4.
[42] QCOSS, sub 21, Etrog, p 4; Queensland Consumers' Association, sub 20, p 2.
[43] EEQ, sub 4, pp 1–2.
[44] Origin, sub 7, pp 1–2.

QCOSS also considered that any costs associated with the free usage period should be recovered through higher usage charges at other times of the day, not through fixed charges, so as not to remove incentives and benefits for households using the tariff.[45]

Several stakeholders raised concerns about potential equity and bill impacts:

- EEQ highlighted the risk of bill shock for customers unable to shift electricity use to the free usage period and noted that some customers may face inequitable outcomes if they cannot alter their consumption patterns.[46]
- Origin noted that customers unable to shift load – particularly renters and lower-income households – could be worse off if higher charges apply outside the free period.[47]
- QCOSS raised broader equity concerns, including that benefits may primarily accrue to households with batteries, which vulnerable customers and renters are less likely to access. It also noted that restricting access to customers with smart meters may create inequities where barriers to installation of smart meters exist (for example, due to the costs of upgrading meter boards or for renters).[48]
- QEUN emphasised the need for transparency around modelling to support the SSO given the potential impacts on customer bills.[49]

Decision

We appreciate stakeholders' views on the potential introduction of an SSO. These views may assist the Minister and the Queensland Government in considering whether, and how, such a tariff could be introduced in regional Queensland in future.

We have not identified any issues that would prevent introducing a solar sharer tariff into notified prices. If the Minister decides to introduce such a tariff in regional Queensland, we consider it would be reasonable, at least initially, to align its design with the SSO implemented in SEQ. This would provide consistency with SEQ arrangements and reduce complexity in customer communication and education. However, the tariff should be reviewed over time to respond to any issues specific to regional Queensland that may arise.

Key tariff design features under this approach include:

- setting the zero-cost electricity (free usage) period from 11 am to 2 pm, consistent with SEQ. This period aligns with the off-peak window for the underlying network tariff and would operate alongside existing network price signals that encourage daytime use
- adopting the same reasonable use cap arrangements as the SSO. Under the SSO, customers can use up to 24 kWh per day during the free usage period at no cost,[50] with usage above this cap charged at the off-peak rate.[51] The cap should be reviewed over time to ensure it remains appropriate for regional Queensland and to identify and respond to any unintended network impacts
- recovering costs incurred during the free usage period through adjustments to usage charges that apply at other times of the day. These include wholesale energy costs, environmental scheme costs and network charges. Similar to arrangements under the SSO, these costs could be redistributed using the TOU load profile currently applied for residential tariffs (i.e. costs

[45] QCOSS, sub 21, Etrog report, p 4.
[46] EEQ, sub 4, pp 1–2.
[47] Origin, sub 7, pp 1–2.
[48] QCOSS, sub 21, Etrog report, p 3.
[49] QEUN, sub 11, pp 1–2.
[50] *Competition and Consumer (Industry Code–Electricity Retail) Amendment Regulations 2026*, s 46.
[51] AER, *Default market offer 2026–27*, final determination, May 2026, p 97.

are reapportioned to usage charges in other periods of the day on a volume-weighted basis).[52]

As stakeholders also said in their submissions, customer education would be important if a solar sharer tariff is introduced in regional Queensland. Customers would require clear information about how the tariff operates and how changes in consumption patterns may affect bills. This would help customers make informed choices and reduce the risk of bill shock. Retailers would play an important role in this process.

We understand stakeholders' interest in introducing a solar sharer tariff in regional Queensland to provide customers with access to the potential benefits of the tariff and maintain consistency with SEQ arrangements. Under the N+R framework, introducing a solar sharer tariff would require a policy direction from the Minister. The Minister has not asked us to establish a solar sharer tariff as part of this determination. However, a solar sharer tariff could be introduced in a future price determination, including a supplementary determination during 2026–27 if the Minister decides to do so (or issues a delegation to us).[53]

3.2.2 Small to large customer transitional tariff

Under Queensland legislation, small customers are defined as customers that consume less than 100 MWh of electricity annually. These customers generally access simpler tariffs, often based on a fixed daily charge and an energy usage charge (c/kWh). In regional Queensland, the most common small business customer tariff is the flat-rate tariff 20.

Once a small business customer consumes more than 100 MWh annually, they are classified as a large customer and move onto more cost-reflective large customer tariffs, which typically include daily charges, usage charges and demand charges. This can lead to a sharp bill increase, primarily because of the higher large customer prices, as well as the more complex demand-based tariff structures.

The Minister asked us to consult with stakeholders on a possible new tariff that could assist small business customers transition to large customer tariffs when their usage exceeds 100 MWh per year, and they are reclassified as a large customer.

The Minister also indicated the tariff could include fixed, usage and demand charges, with rates set so that a typical customer using 100 MWh annually would see only a minimal bill increase. Rates would escalate so that a customer using 160 MWh annually would pay a similar amount to a typical customer on tariff 44A.

Stakeholder comments

Stakeholders identified the legislated 100 MWh annual consumption threshold that separates small and large customers as the core issue requiring reform and preferred increasing the threshold to 160 MWh rather than introducing a transitional tariff. In particular:

- Canegrowers said the current threshold creates a pricing 'cliff', resulting in disproportionate bill increases that are not reflective of underlying cost changes. It considered raising the threshold would directly address the 'root cause of customer detriment' and provide a more durable solution than relying on increasingly complex tariff mechanisms.[54]

[52] AER, *Default market offer 2026–27*, final determination, May 2026, p 98.
[53] Electricity Act, s 90(3).
[54] Canegrowers, sub 1, pp 1–2, sub 16, p 1.

- Cotton Australia did not support a transitional tariff, which it considered would introduce a very significant amount of complexity. Instead, it recommended increasing the large customer threshold to 160 MWh per annum.[55]
- QFF's preference was to increase the large customer threshold to 160 MWh per annum instead of developing a transitional tariff. However, QFF said it would support a transitional tariff in-principle only in preference of the status quo, and only if it was practically applied and offered improved outcomes for agricultural businesses. It also raised concerns about the practicality, transparency and complexity of a transitional tariff and recommended engagement and testing with impacted customers.[56]

CPAQ supported introducing a transitional tariff but emphasised the importance of clear communication, proactive customer notification and sufficient lead time to ensure eligible businesses understand and can access the tariff.[57]

EEQ also supported a transitional tariff but noted that further detail would be required around tariff design, including the pricing glidepath, eligibility criteria, duration and how any cost under-recovery would be managed (particularly where many customers use the transitional tariff).[58]

Decision

The Minister's delegation asks us to consult on a potential transitional tariff, rather than to introduce such a tariff as part of this review. The Minister also indicated a broad tariff concept involving a new transitional tariff with a fixed, usage and demand charge and an inclining rate profile between 100 MWh and 160 MWh.

Stakeholder feedback indicated a strong preference for increasing the large customer threshold from 100 MWh to 160 MWh per annum, rather than introducing a transitional tariff for customers within that consumption range. Stakeholders generally viewed the legislated threshold itself as the key issue. While some stakeholders indicated support for a transitional tariff, this was generally presented as a fallback option if changes to the threshold were not pursued.

As the large customer threshold is set in legislation, this is a matter for the Queensland Government to consider and is beyond the scope of our price determination. The government may wish to review the ongoing appropriateness of the existing consumption threshold alongside any future consideration of the objectives and design of a transitional tariff.

Developing a practical tariff option would require detailed information on the relevant customer cohort, including the number of customers affected and their consumption and demand characteristics within the 100–160 MWh range. This information is primarily held by retailers, including EEQ.

As this tariff cannot be set under the usual N+R method and pricing framework, any future implementation would require specific policy direction from the Minister, including on the tariff scope, customer eligibility and duration of the tariff. When developing the policy for any proposed transitional tariff, consideration should also be given to the potential competition impacts the tariff may have in the retail electricity market for large customers and any equity considerations for large customers that have previously switched to a market offer and cannot revert to EEQ due to the legislated non-reversion policy.

[55] Cotton Australia, sub 17, p 5.
[56] QFF, sub 12, pp 4–5, sub 22, pp 6–7.
[57] CPAQ, sub 2, pp 5–6.
[58] EEQ, sub 4, p 2, sub 18, p4.

However, further to some of the issues raised by EEQ regarding tariff scope and design, we have provided a preliminary assessment of:

- considerations that may be relevant to designing a transitional tariff
- broader matters that may be relevant to consider before the tariff is implemented.

Transitional tariff design

Designing a transitional tariff involves both policy and practical considerations. Defining the objective of the tariff and the customer cohort it is intended to support will assist and inform tariff design, eligibility settings and duration.

For example, if a transitional tariff is intended to operate as a temporary bridge between small and large customer tariffs, eligibility and duration settings would need to ensure customers eventually move to standard large customer tariffs. Alternatively, if the tariff applies more broadly to customers whose consumption remains between 100 and 160 MWh, it may operate more like an ongoing de facto tariff class.

These considerations may influence the intended scope of the tariff, potential CSO implications and broader market impacts. They may also affect practical implementation of the tariff by retailers.

Table 3.2 summarises several information requirements and design considerations that may be relevant to the development of a transitional tariff in future.

Table 3.2: Key information required to design a transitional tariff

Issue	Information description
Glidepath design	• How demand charges would be introduced (e.g. starting at $0 and increasing) • Whether rate escalation would occur over time or only when customers meet specified usage bands between 100 and 160 MWh
Eligibility	• Which customers would be eligible (e.g. customers that have only recently been reclassified as large customers or all customers within the 100–160 MWh band)
Duration	• How long customers would remain eligible (e.g. for a fixed period, or until 160 MWh is reached, or until consumption stabilises)
Interaction with network tariffs	• Whether the tariff would be linked to an existing network tariff or operate as a retail-derived tariff • How network cost recovery risks would be managed
Targeted bill impact assessment	• Which load profiles and demand levels would be used to assess the impact on bill outcomes for consumption between 100 and160 MWh
Implementation considerations	• Retailer billing capability, metering requirements and administrative processes for moving customers onto and off the tariff

Other considerations

Potential CSO implications

A key design consideration is the potential for a permanent transition outcome, where some customers exceed the 100 MWh threshold but never approach 160 MWh if their consumption stabilises at a lower level. As a result, the transitional tariff would effectively operate as a de facto threshold change without a corresponding legislative amendment.

The implications of this outcome should be considered in light of the intended policy objective.

Depending on how eligibility is defined, a transitional tariff could apply to a substantial proportion of large customers in regional Queensland. Based on customer usage data, around half of large customers consume less than 160 MWh annually. If eligibility is broadly defined (for example, if the tariff applies to all customers within the 100–160 MWh band), the tariff could apply to a large share of the large customer population. This may have implications for:

- the scale of any associated subsidy arrangements
- the size of the beneficiary cohort
- the long-term fiscal exposure associated with the tariff.

Competition and market impacts

Introducing a regulated transitional tariff may affect competition in the large customer electricity market segment in regional Queensland. If the regulated price level for customers in the 100–160 MWh band is reduced, this may:

- reduce the attractiveness of existing market offers
- weaken incentives for retailers to compete for these customers.

This highlights a trade-off between supporting customers during reclassification and maintaining competitive pressure in the large customer market.

Equity considerations

If the transitional tariff is introduced into notified prices, this may create differences in access to a transitional tariff between otherwise similar customers. For example, large customers that have switched to a market offer will not be able to return to EEQ under the existing legislated non-reversion policy.

Duration and phase-out considerations

A key design issue is specifying the duration of the tariff. Once the tariff is introduced, it may be difficult to remove, particularly if a large group of customers benefit from the arrangement. Possible approaches to defining duration could include:

- time-limited eligibility (i.e. customers can only stay on the transitional tariff for a fixed time)
- usage-based exit triggers (i.e. after a customer's consumption reaches 160 MWh, customers move to a standard tariff and are not eligible to access the transitional tariff in future)
- cohort-based sunset provisions (i.e. the tariff applies to a specific group of customers for a set time-period after which no new customers access the tariff)
- scheduled policy review points (i.e. the government reviews the arrangements at set time intervals to decide whether the tariff continues, changes or is removed).

Clearly defining duration would help ensure the tariff operates as intended and does not become a permanent customer class (if that is not the intended objective).

Implementation by retailers

Implementing a transitional tariff would involve practical considerations for retailers, including billing system capability, eligibility monitoring and processes for moving customers onto and off the tariff and between usage bands.

These operational matters would likely need to be addressed by retailers, including Ergon Energy Retail, before the tariff is implemented.

3.3 Other tariff matters

3.3.1 Transition and expiry of obsolete tariffs

A number of obsolete retail tariffs[59] are scheduled to expire on 30 June 2026 (see Table 3.3). The delegation requires us to consider whether these tariffs should be phased out as scheduled or extended into 2026–27.

Table 3.3: Existing obsolete tariffs scheduled to expire on 30 June 2026

Small business tariffs	Large customer tariffs
Tariff 22B (TOU inclining-band tariff)	Tariff 44 (demand (small threshold) tariff)
Tariff 22C (TOU inclining-band tariff) (solar soaker tariff variant)	Tariff 45 (demand (medium threshold) tariff)
Tariff 24A (TOU demand tariff)	Tariff 46 (demand (large threshold) tariff)
Tariff 62A (limited access obsolete TOU declining-block tariff)	Tariff 50 (seasonal TOU demand tariff)
Tariff 65A (limited access obsolete TOU tariff)	Tariff 50A (TOU demand tariff)
Tariff 66A (limited access obsolete fixed dual-rate demand tariff)	Tariff 52A (seasonal TOU demand tariff for CAC supplied at 33 or 66 kV)
	Tariff 52B (seasonal TOU demand tariff for CAC supplied on an 11 or 22 kV bus)
	Tariff 52C (seasonal TOU demand tariff for CAC supplied on an 11 or 22 kV line)

Most of these tariffs were made obsolete in our determination of 2025–26 notified prices following changes to the underlying network tariffs approved by the AER.[60] At that time, the tariffs were made obsolete with a 12-month phase-out period to allow affected customers time to understand the changes, alternative tariff options and adjust usage if required, while limiting the period during which retail tariffs were misaligned with network tariffs.

Stakeholder comments

Stakeholders generally supported allowing most obsolete tariffs to expire as scheduled,[61] with a few exceptions:

- **Small business solar soaker tariff 22C** – QFF, Canegrowers and Cotton Australia considered tariff 22C (the small business 'solar soaker' tariff with obsolete TOU windows) should be retained or replaced with a similarly structured tariff.[62] QFF said this tariff provides 'highly effective' pricing signals that incentivise irrigators to invest in technology and adjust their operations to daytime hours. It considered the successor tariff (tariff 22E) does not provide the same financial incentives because its shorter off-peak period means more

[59] Obsolete tariffs are only available to customers who were on the tariff when it became obsolete. Customers who move to another tariff cannot return to the obsolete tariff.
[60] QCA, *Regulated retail electricity prices 2025–26*, final determination, June 2025, pp 10–13.
[61] EEQ, sub 4, p 3; Cotton Australia, sub no 3, p 5; QFF, sub 12, pp 5–6.
[62] QFF, sub 22, p 7; Canegrowers, sub 16, p 1; Cotton Australia, sub 17, p 5.

daytime usage falls within the shoulder period. QFF said tariff 22C should be retained for a minimum of two years.[63]

- **Limited access irrigation tariffs 62A, 65A and 66A** – Ergon Energy Retail supported continuing these tariffs, noting that some customers currently on these tariffs have expressed a preference for their retention. However, it also noted some customers on these tariffs may achieve savings on alternative tariffs.[64]

  QFF, Canegrowers and Cotton Australia did not oppose the scheduled phase out of these tariffs.[65] QFF considered the tariffs do not provide meaningful benefits or reflect contemporary system conditions, while Canegrowers considered they are poorly aligned with current network cost structures and do not provide clear or effective price signals to support efficient electricity use.[66]

Decision

We consider the scheduled phase-out date for obsolete tariffs should only be extended where operational or practical constraints make it difficult for customers to transition to standard tariffs.

Affected customers were provided a 12-month transition period following the 2025–26 determination. We consider this period was sufficient for customers to understand their alternative tariff options and adjust their usage if necessary. This is particularly the case for large customers, who are generally more sophisticated electricity consumers.

Some stakeholders expressed a preference to retain tariff 22C, primarily because its wider off-peak TOU window provides stronger incentives for customers to shift consumption into daytime periods than the TOU windows introduced under last year's network tariff reforms. We understand this is an important issue for stakeholders (particularly from the agricultural sector), and note similar concerns were raised in the context of the large customer solar soaker tariff. However, the TOU windows for tariff 22C are no longer reflected in the relevant underlying network tariffs. In the absence of a policy direction from the Minister, the N+R framework requires retail tariffs to align with the structure of underlying network tariffs as soon as practicable.

We note Ergon Energy Retail's suggestion that the phase-out date for tariffs 62A, 65A and 66A should be extended. However, these tariffs have already been subject to an extended transition period, with the phase-out process originally commencing in 2012–13.[67] In our view, a further extension is not warranted.

3.3.2 Access requirements for tariffs 60A and 60B

Access to tariffs 60A and 60B (the large customer load control tariffs) is limited to only those parts of Ergon Energy Network's distribution network where its standard load control signalling operates.[68]

[63] QFF, sub 22, pp 2–3, 7.
[64] EEQ, sub 4, p 3.
[65] QFF, sub 12, p 6; Canegrowers, sub 1, p 6; Cotton Australia, sub 3, p 5, sub 17, p 5.
[66] QFF, sub 12, p 6; Canegrowers, sub 1, p 6.
[67] Tariffs 62A, 65A and 66A are based on transitional network tariffs introduced by Ergon Energy Distribution in 2021–22, which replaced the earlier obsolete retail tariffs 62, 65 and 66 (first made obsolete in 2012–13). The transitional network tariffs are scheduled to expire on 1 July 2026.
[68] Other access requirements for these tariffs also apply, including these tariffs not being available to customers connected to the Essential Energy network within Queensland.

Stakeholder comments

Ergon Energy Network (EEN) and Energex proposed that the retail tariff schedule be amended to allow customers to access tariffs 60A and 60B in other areas as determined by EEN, where standard load control signalling does not operate. EEN and Energex said this would better accommodate emerging technologies and allow more customers to access and benefit from these tariffs, noting some large customers (including agricultural customers) cannot access these tariffs due to standard load control signalling not operating in their area.[69]

Cotton Australia and QFF also supported amendments to the retail tariff schedule to increase customer access to these tariffs.[70]

Decision

We appreciate the intention to make tariffs 60A and 60B available to more customers and note stakeholders have previously advocated for access to these tariffs in parts of the network where standard load control signalling is not operating.[71]

However, the standard load control signalling requirement reflects a requirement in the approved network tariff arrangements.[72] In accordance with the N+R framework, network tariff requirements should be reflected in the retail tariffs we set. It is also unclear to us whether tariffs of this nature could be made available at the retail level in circumstances that are not provided for in the relevant network tariff arrangements.

We have amended the retail tariff schedule to allow tariffs 60A and 60B to be provided to customers in other circumstances as permitted by network tariff arrangements. This will mean that, if the network tariff arrangements are amended to permit other load control technology to be used, this change will be reflected in notified prices without the need for further amendment to the retail tariff schedule.

EEN and Energex supported these amendments, noting they will need to take actions to give effect to these arrangements, including updates to network systems and the development and rollout of appropriate customer-side equipment. EEN and Energex committed to working closely with stakeholders to progress these changes and ensure they are clearly communicated.[73]

[69] EEN and Energex, sub 5, p 2.
[70] Cotton Australia, sub 17, pp 5–6; QFF, sub 22, p 8.
[71] See, for example, QCA, *Supplementary review: Regulated retail electricity prices 2020–21*, final determination, October 2020, p 13.
[72] EEN, *Tariff Structure Statement: Regulatory Determination Proposal 2025–26*, November 2024, as amended and approved by the AER April 2025, pp 16, 21; EEN, *Ergon Energy Network Tariff Guide: 01 July 2025 to 30 June 2026*, July 2025, p 40.
[73] EEN and Energex, sub 19, p 1.

4 Individual cost components

The notified prices consist of network costs (N component) – for transporting electricity transport via distribution and transmission networks – and retail costs (R component) – for buying and selling electricity to customers – along with other costs.[74]

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

- setting the N component – based on network prices approved by the AER (in this report we are using final prices the AER approved in April 2026)
- 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.[75]

4.1 Network component

The N component includes costs for transporting electricity through transmission and distribution networks, as well as jurisdictional scheme charges[76] and the cost of legacy (accumulation) meters for small customers.[77] These 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 pricing approach we applied in previous determinations.

Stakeholders provided feedback on the structure and level of certain network-driven tariffs, particularly the balance between fixed, demand and volumetric components:

- Canegrowers said the price difference between tariff 34 and standard flat tariffs (such as tariff 20) has narrowed over time, weakening incentives for participation in controlled-load arrangements. It said that tariff 34 usage rates should be reduced to better reflect long-run marginal costs and to preserve customer participation and associated system benefits.[78]
- CPAQ said fixed and demand charges constitute 44–75% of electricity bills for caravan and residential parks, leaving only a small portion linked to actual consumption. It said that tariffs should be rebalanced toward volumetric charges to strengthen incentives for solar, batteries and energy-efficiency investment.[79] Similarly, another stakeholder noted service charges had increased to more than half of the total bill and queried why the service charges in the Energex area are less than in regional Queensland, where the UTP applies.[80]

[74] These other costs and related adjustments are discussed in Chapter 5.
[75] For small customers, we also include the cost of advanced digital metering services in the R component, to reflect the ongoing rollout of these meters in regional Queensland (see section 4.2).
[76] In Queensland, these charges include the Solar Bonus Scheme and Australian Energy Market Commission levy costs.
[77] Since 2025–26, network prices approved by the AER include the costs of legacy (accumulation) meters. See AER, *Energex Electricity Distribution Determination 2025 to 2030: Overview*, final decision, April 2025, p 31.
[78] Canegrowers, sub 1, pp 6–7.
[79] CPAQ, sub 2, pp 3–4.
[80] D Sutcliffe, sub 15, p 1.

- Cotton Australia queried why there is a disparity in changes in the network cost component between the large and small customer classes.[81]

We recognise stakeholders' concerns regarding tariff structures and the relative weight placed on fixed, demand and volumetric charges. However, network tariff design and cost recovery issues are determined through the AER's regulatory processes and not by the QCA. Our role in setting notified prices is to apply the network prices approved by the AER in accordance with the UTP and the N+R methodology. We encourage stakeholders to raise queries about how network prices are determined with the AER.

We have used the AER-approved network prices to set notified prices in this determination.[82]

Table 4.1 sets out the basis on which we determine the N component.

Table 4.1: Basis for determining the N component

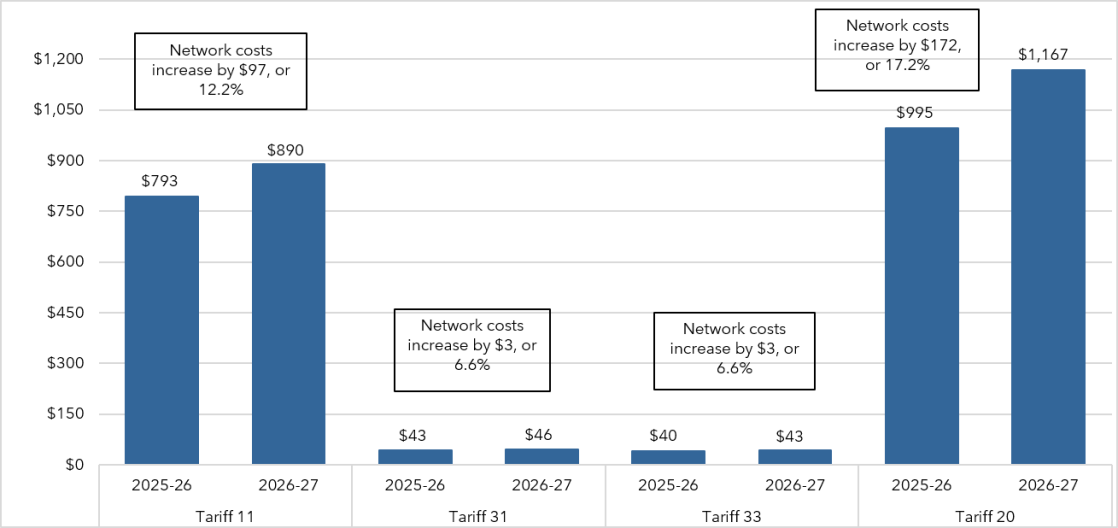
Tariff	Basis
Small customers	
Flat and secondary load control tariffs	Relevant Energex network prices (being the charges and tariff structures levied by Energex in SEQ)
All other existing retail tariffs (small customers)	Relevant Energex network prices but utilising EEN's tariff structures
Large customers	
New large customer solar soaker tariff (tariff 50C)	Based on the relevant network price for existing large customer tariff 50B (see section 3.1.1)
All other existing retail tariffs (large customers)	Relevant network prices for EEN's east distribution pricing zone (being the Ergon Energy pricing region with the lowest cost of supply that is connected to the NEM)

Network costs included in notified prices

Network costs have increased for small and large customers compared to last year. The change to the annual bill for a typical customer is shown in Figures 4.1 and 4.2.

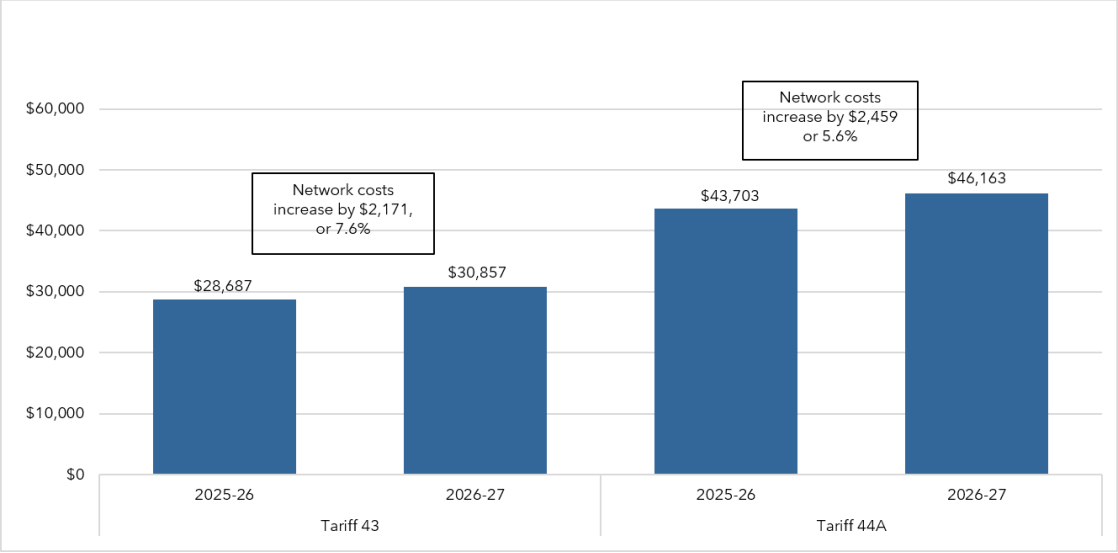
[81] Cotton Australia, sub 17, pp 4–5.
[82] These were updated from the draft network prices used in the draft determination.

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



Note: 1. Bill changes (dollar amounts) are rounded. 2. Percentage changes are based on unrounded amounts.

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



Note: 1. Bill changes (dollar amounts) are rounded. 2. Percentage changes are based on unrounded amounts.

4.2 Retail component

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) – the costs of purchasing electricity from the NEM – as well as other energy-related costs such as Renewable Energy Target obligations and energy losses.

This year, we engaged ACIL Allen (ACIL) to provide expert advice and estimate energy costs. The information we relied on from ACIL's report is available on our website and has been updated for this final determination.

Wholesale energy costs

The WEC reflects the costs retailers incur when purchasing electricity from the NEM to meet customer demand. Because spot prices in the NEM can fluctuate significantly, retailers typically manage this risk using hedging strategies, such as financial contracts and operational methods.[83]

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

- **a market hedging approach** – which estimates the WEC for a retailer that manages spot price risk by using ASX Energy futures contracts
- **the most up-to-date information** – which includes contract data up to 6 May 2026.

This approach is generally consistent with the methodology we used in previous years (see Box 5).

Box 5: Estimating the WEC

The estimated WEC for a given year is based on two key components:[84]

- **wholesale energy spot prices** – which are simulated using assumptions about:
  - supply conditions in the NEM, such as power plant availability and renewable energy production
  - demand changes, based on weather data, historical demand, solar uptake and forecasts from the Australian Energy Market Operator (AEMO)
  - generator bidding behaviour and how it may change with market conditions and costs
- **retailers' hedging strategies and contract prices** – the WEC is estimated using a model that simulates an efficient retailer hedging its exposure to spot price risk by using publicly available ASX Energy contracts. Key inputs include:
  - trade-weighted average prices for quarterly base and cap contracts[85] using Queensland trade data up to 6 May 2026
  - contract trading that occurs several years before the delivery year (for example, trading for 2026–27 contracts began in mid- to late 2023), reflecting how retailers typically lock in costs early.

This model produces 605 annual hedged energy cost estimates. We adopt the 95th percentile from these estimates as our WEC to reduce the risk of understating the costs a prudent retailer could face in the NEM.[86]

We consider this approach produces robust and transparent WEC estimates.[87] It uses a large number of simulations and incorporates the latest available market data.

Stakeholders raised several concerns about our approach for estimating the WEC.

[83] Spot prices are settled every 5 minutes and currently can range from -$1000 to $20,300 per megawatt hour.
[84] This summarises ACIL's method used for estimating the WEC. See ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2026, pp 7–21.
[85] Consistent with past reviews, the trade-weighted contract price incorporates data on base contract call options.
[86] We adopt the 95th percentile because wholesale electricity prices in the NEM have greater potential to increase than to decrease.
[87] ASX Energy contract prices are publicly available. ACIL also found WEC estimates from previous reviews were generally consistent with subsequent (actual) movements in the trade-weighted contract prices. See ACIL's energy costs report, pp 31–33.

QEUN's concerns centred on the reliance on a single consultant to estimate energy costs for both the QCA and the AER. It noted that energy costs account for around 40% of a typical small customer bill and that the estimates are produced using a proprietary model. QEUN said the modelling should be independently scrutinised to ensure there are no inaccuracies that could lead to overstated electricity prices.[88] It also noted that upcoming changes to the DMO framework and the introduction of the solar sharer offer may affect energy cost estimates and increase the importance of ensuring the estimates are robust and transparent.[89]

We acknowledge QEUN's comments on the importance of the energy cost estimates. While some elements of the model are proprietary, the key methodology, assumptions and cost drivers are published and are subject to scrutiny. Substantive issues raised by stakeholders are tested with ACIL and incorporated where appropriate. If QEUN has specific concerns with elements of the methodology, we encourage it to identify these so they can be considered transparently.

EEQ said it continues to have concerns that the hedging strategy used to estimate the WEC does not reflect how retailers manage risk in practice. It noted the model relies heavily on flat swaps and cap contracts and does not utilise 'shaped' products, such as evening peak contracts, commonly traded in over-the-counter (OTC) markets.[90] EEQ said that our methodology does not reflect the practical reality faced by retailers and that multiple retailers have raised the same concern with the AER.[91]

We acknowledge EEQ's concerns. However, the hedging strategy (including product mix) is intended to provide a benchmark estimate of the WEC and is not designed to replicate the hedging practices of any individual retailer. The methodology provides an objective and transparent basis for estimating wholesale energy costs using publicly available ASX contract data. While retailers may adopt alternative hedging strategies or use products that more closely align with their individual risk exposures, this does not in itself suggest the method is inappropriate.[92]

EEQ did not provide evidence that the current approach materially understates efficient wholesale energy costs or that the use of alternative products would produce more robust estimates. While EEQ noted that similar concerns have been raised with the AER, our method differs from the AER's approach to estimating the WEC. The AER estimates wholesale costs at the 50th percentile of modelled outcomes and applies a separate volatility allowance. By contrast, we estimate the WEC at the 95th percentile to account for the asymmetric risk of wholesale (spot) price increases.[93] We therefore continue to consider the current approach provides an appropriate and transparent estimate of the WEC for notified prices.

Demand profiles

We typically use 2 to 3 years of historical demand data for our WEC estimates. This year, we used demand data from 1 October 2023 to 30 September 2025, adding an additional year of data relative to last year.[94] We also made one additional refinement to improve the quality of the data.

[88] QEUN, sub 11, pp 1–3.
[89] QEUN, sub 11, p 6.
[90] EEQ, sub 4, pp 3–4. Evening peak contracts better align hedge coverage with the periods of higher wholesale price risk (i.e. typically 4 pm to 10 pm).
[91] EEQ, sub 18, p 2.
[92] Alternative strategies include, for example, OTC contracts and/or investing in own generating units.
[93] Again, wholesale prices in the NEM have greater scope to increase than to decrease. The 95th percentile also accounts for the risk that contract market conditions may change between the data cut-off date (6 May 2026) and the period covered by the determination (1 July 2026 to 30 June 2027).
[94] In the 2025–26 review, we were limited to one year of demand data because we excluded an artificial uplift in the Queensland NSLP between 1 October 2021 and 30 September 2023. This uplift reflected a temporary manual adjustment applied by AEMO to address negative demand values associated with the introduction of 5-minute settlements. See ACIL's report, pp 15–16. As the adjustment was removed after 1 October 2023, it does not affect data used for this determination.

This was to use interval meter data for the controlled loads, which we obtained directly from EEQ.[95] This data gives us more accurate profiles for the controlled loads.[96]

We continue to combine the net system load profile (NSLP)[97] with advanced digital meter (ADM) data when considering historical demand profiles. Using the interval meter data improves our estimate of the cost of supplying energy to small customers because, in combination with the NSLP, it better reflects the shape of the demand profile. Further, and consistent with our 2024–25 and 2025–26 reviews, the ADM data *includes* demand satisfied by solar PV exports, as the resulting profile reflects total demand that a retailer needs to supply to its customers (i.e. not total demand less solar exports).[98]

EEQ acknowledged that we seek to address retailer shape exposure through a combination of notified prices and the regional FiT.[99] However, it said the regulatory framework constrains its ability to manage shape risk in a manner consistent with a prudent retailer operating in SEQ.[100] In particular, the framework does not adequately capture EEQ's exposure to an increasingly peaky load profile. EEQ considers that the unique regional Queensland regulatory environment warrants an additional adjustment factor to appropriately reflect this risk.[101]

Our view is that the relevant demand profile for notified prices is total demand, including demand satisfied by solar exports, as notified prices apply to all electricity consumed. While retailers may choose to hedge against net demand, additional costs associated with solar exports can be reflected through the regional solar FiT framework. Consistent with this approach, we consider the impact of solar exports when setting the regional solar FiT.[102]

Further, notified prices are set using benchmark costs and outcomes observed in the competitive SEQ market, consistent with the UTP. They are not intended to replicate EEQ's specific operating environment or risk exposure. Taking this into account would be inconsistent with the broader notified pricing framework. Further, our WEC method recognises asymmetric risk by using the 95th percentile of modelled outcomes.

Outcomes and key drivers

WECs decreased compared to last year.

- **For small customer primary tariffs** – the WEC decreased by 13.0%
- **For small customer secondary load control tariffs** – the WEC decreased by 4.0% and 10.2% for tariffs 31 and 33 respectively
- **For large customer tariffs** – the WEC decreased by 9.8%.[103]

[95] The demand profiles correspond to the super economy (NTC 9000) CLP and economy (NTC 9100) CLP profiles.
[96] These datasets improve on AEMO's Market Settlement and Transfer Solutions (MSATS) data. MSATS uses a sample of accumulation meter customer data, whereas EEQ's dataset reflects a more comprehensive set of interval meter data. The new data also enables us to remove controlled load volumes from the interval meter data previously provided by AEMO.
[97] AEMO publishes NSLPs used to approximate the demand of customers on accumulation meters.
[98] See ACIL's energy costs report, pp 11–12.
[99] Shape exposure arises when a retailer seeks to purchase products (e.g. futures contracts) to meet expected demand but can only purchase the products in fixed quantities that do not exactly match expected demand. This may result in the retailer being under or over-contracted and therefore require the retailer to meet residual demand through spot market purchases at the time of supply.
[100] EEQ said retailers hedge against net demand (i.e. total demand less demand met by solar exports) and said that separately modelling demand and export profiles may result in hedge positions that are overly long during the middle of the day and short during evening peaks (see EEQ, sub 4, pp 4–5).
[101] EEQ, sub 18, p 2.
[102] See QCA, *Solar feed-in tariff for regional Queensland 2026–27*, final determination, June 2026.
[103] The WEC for very large customers (i.e. connection asset customers (CAC) and individually calculated customers (ICC)) decreased by 3.6%.

These reductions are primarily driven by lower wholesale electricity spot prices in 2025, reflecting higher availability of Queensland coal generators, lower gas prices and continued uptake of battery energy storage systems (BESS) and renewable generation. Together, these factors reduced both the level and volatility of wholesale spot prices:[104]

- **For small and large customer primary tariffs (tariffs 11, 20, 43, 44A)** – demand profiles have again flattened slightly relative to last year. The largest reductions in the WEC occur for tariffs 11 and 20, whose demand profiles have been most affected by changes in demand shape associated with increasing renewable energy generation and battery uptake.[105]
- **For small customer load control tariffs (tariffs 31 and 33)** – the decrease in WEC is greater for tariff 33. This is because tariff 33 demand is more concentrated in the evening peak period and therefore it benefits more from the reduction in evening peak prices and price volatility.[106,107]

Time-varying wholesale energy costs (small and large customer tariffs)

For TOU tariffs 12E, 22E and the new large customer tariff 50C, we use time-varying WEC estimates to create stronger differences between peak and non-peak periods, compared to tariffs 12D, 22D and 50B, on which these tariffs are based.[108]

Consistent with previous determinations, the time-varying WECs are based on ACIL's advice and are derived by:

- using the WEC estimates for tariffs 12D, 22D and 50B
- calculating weightings for different times of the day based on demand-weighted wholesale spot price variations, where non-peak periods (daytime) generally have lower prices, while peak periods (evening) have higher prices
- applying these weightings to allocate lower costs to non-peak periods (typically daytime) and higher costs to peak periods (typically evening)
- The time periods align with network tariff structures approved by the AER.

This method maintains the same total WEC as the underlying tariffs (12D, 22D and 50B) but redistributes costs across time periods to strengthen price signals.[109] Table 4.2 sets out the time-varying WEC estimates included in notified prices this year.

[104] A substantial amount of utility scale BESS capacity is expected to come online over the next 12 months, contributing to lower contract prices in 2026–27, compared with 2025–26.
[105] Recent determinations have noted that continued uptake of rooftop solar and utility-scale solar generation has reduced daytime demand. However, in this review, load profiles appear to be stabilising due to strong uptake of behind-the-meter BESS, which is largely offsetting the continued growth in solar PV.
[106] The reduced volatility also reflects the expected increase in utility-scale BESS capacity in 2026–27.
[107] The change in data sources for the controlled loads does not materially affect the WEC, as the demand profile shapes are similar across both datasets.
[108] The basis for this approach is set out in the *2023-24 final determination,* sections 3.2.1 and 4.2.1. As tariff 22C was made obsolete in our 2025–26 determination, the time-varying WEC is now applied to tariff 22E.
[109] Time-varying WECs for tariffs 12E and 22E are based on the Energex residential and small business WEC, while the time-varying WEC for tariff 50C is based on the Ergon Energy Standard Asset Customer (SAC) demand WEC (i.e. SAC Large).

Table 4.2: Time-varying WECs for tariffs 12E, 22E and 50C

Period	Tariff 12E[a] c/kWh	Tariff 22E[b] c/kWh	Tariff 50C[c] c/kWh
Peak (evening)	18.87	20.43	17.65
Non-peak (day)	4.17	4.01	3.18
Shoulder (night)	13.98	13.12	10.30

a For tariff 12E, 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 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.
c For tariff 50C, 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.

Other energy costs

Retailers incur several other energy costs when buying electricity from the NEM. These include costs associated with renewable energy obligations, market operation fees, ancillary services, prudential requirements and energy losses.

We estimate these costs based on ACIL's advice, which draws on publicly available and reliable data sources to reflect the other costs retailers are likely to face.[110] Table 4.3 summarises these costs and the approach used to estimate them.

[110] See ACIL's energy costs report, pp 25–31, 52–62.

Table 4.3: Other energy costs – description and estimation approach

Costs	Description	Approach to estimation
Renewable energy target (RET) costs	Costs of buying certificates to meet the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES)[111]	LRET costs – use forward prices for large-scale generation certificates (LGC) and renewable power percentage (RPP), based on mandated targets and estimates of electricity acquisitions.
		SRES costs – use the clearing house price for small-scale technology certificates (STC) and the small-scale technology percentage (STP).
NEM fees	Fees paid to AEMO for operating the NEM	Use AEMO's latest budget report, which includes fixed and variable fees.[112] We used AEMO's 2026–27 draft budget report (published in April 2026) for this final determination.[113]
Ancillary services	The costs of services used by AEMO to maintain power system safety, security and reliability	Use the average historical costs over the past 52 weeks, published by AEMO.
Prudential costs	The costs of providing financial guarantees to AEMO and lodging initial margins with the ASX for futures contracts	Use AEMO's prudential requirements and ASX margin requirements for futures trading.
Energy losses	The cost of additional electricity retailers must purchase to account for transmission and distribution losses when electricity is transported across the network[114]	Use AEMO's published transmission and distribution loss factors. We used AEMO's 2026–27 loss factor reports (published in April 2026) for this final determination.[115]

[111] LRET and SRES schemes encourage renewable energy generation and reduce greenhouse gas emissions. Retailers meet these obligations by purchasing LGCs and STCs created when eligible renewable electricity is generated.
[112] See ACIL's energy costs report, p 25. The fixed NEM fee is recovered in the daily supply charge as a fixed energy cost component. This change was implemented last year following changes to AEMO's NEM fee structure.
[113] We used fees from the 2025–26 budget report in the draft determination.
[114] Energy losses are applied to the combined value of the WEC and other energy costs to determine the total loss-related cost.
[115] We used the 2025–26 loss factors in the draft determination.

Stakeholders raised several issues regarding our estimates of other energy costs. We considered these matters and, while we updated our NEM fee estimate to reflect new information, we have not otherwise changed our approach. Key points stakeholders raised were the:

- LGC allowance – EEQ said the methodology should incorporate a broader range of broker prices to reflect industry practice and improve robustness. We consider our existing sources provide sufficiently robust estimates. As broker prices are generally closely aligned, including additional brokers' estimates would be unlikely to materially affect/improve our estimate (and would increase complexity and costs).
- NEM fees – EEQ noted that AEMO's NEM fee structure is expected to change from 1 July 2026. We have updated our estimate to reflect the latest available information (Table 4.3).

Other energy costs[116] have decreased compared to last year:

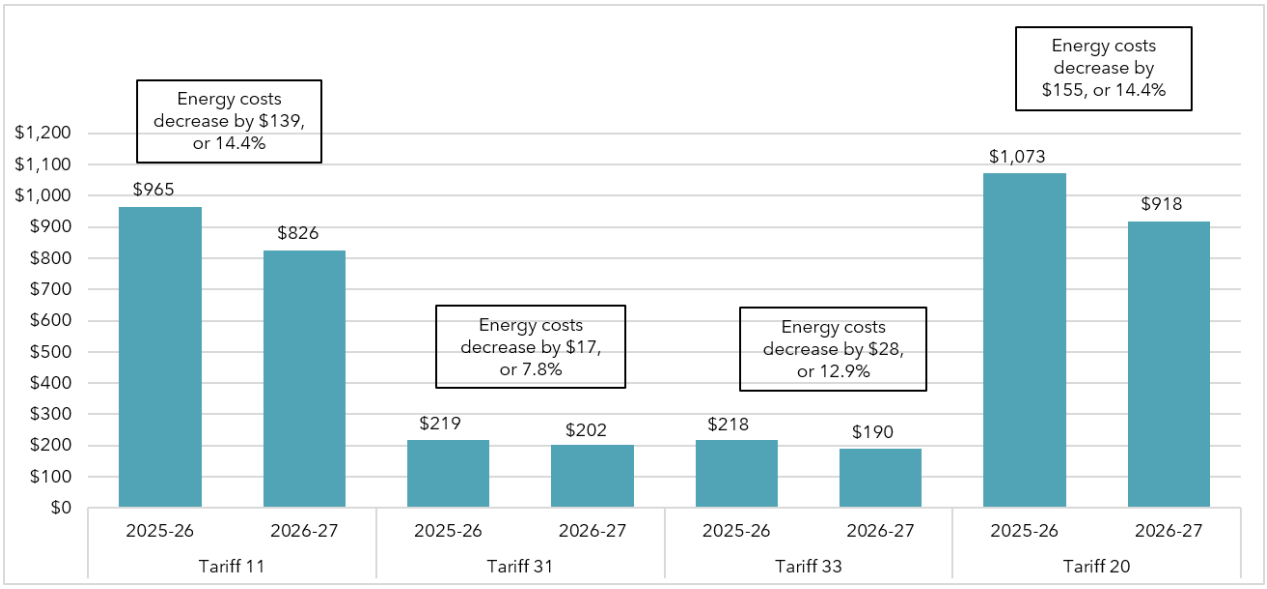
- for small customer tariffs – by 28.9% ($4.58/MWh)
- for large customer tariffs – by 28.9% ($4.24/MWh).

The reasons for these changes are explained in ACIL's report.[117] We have updated estimates as relevant for this final determination (Table 4.3).

Total energy costs included in notified prices

Overall, total energy costs are estimated to decrease for customers. Figures 4.3 and 4.4 compare the total energy costs included in notified prices with last year's estimates, by tariff and customer type.

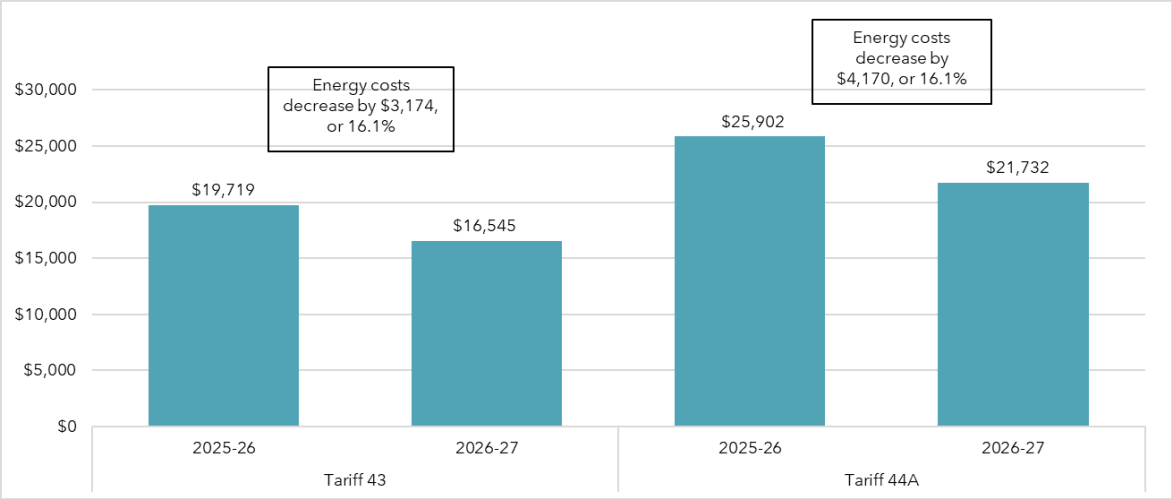
Figure 4.3: Energy costs – small customer tariffs (incl GST)



Note: 1. Bill changes (dollar amounts) are rounded. 2. Percentage changes are based on unrounded amounts.

[116] This excludes costs associated with energy losses and the fixed NEM fee.
[117] The changes to each cost category are set out in ACIL's energy costs report, pp 55, 61.

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



Note: 1. Bill changes (dollar amounts) are rounded. 2. Percentage changes are based on unrounded amounts.

4.2.2 Retail costs – small customers

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 the risk associated with providing retail electricity services.

To date, we have determined retail cost allowances using a well-established benchmarking methodology that estimates the costs an efficient retailer would incur, based on market data.[118]

We review the benchmark allowances periodically to ensure they remain appropriate and reflect costs associated with current retail operating conditions. The last review occurred as part of the 2021–22 notified prices determination.

Stakeholder comments

Stakeholders said it was timely to update the retail cost benchmark using more recent information[119] but had different views on the level of retail costs and the appropriate approach:

- Some stakeholders said technology (such as electronic billing) should reduce retail costs,[120] while others said retail costs are increasing faster than inflation and that CPI indexation may no longer be adequate.[121]
- QCOSS and the Queensland Consumers' Association supported a more detailed reassessment of retail costs, including a bottom-up assessment.[122]

[118] 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 retained.
[119] Queensland Consumers' Association, sub 9, p 1; QCOSS, sub 10, p 5.
[120] Queensland Consumers' Association, sub 20, pp 1–2.
[121] EEQ, sub 4, p 7, sub 18, p 1.
[122] QCOSS, sub 10, p 5, sub 21, Etrog report, pp 8–9; Queensland Consumers' Association, sub 9, p 1.

- Some stakeholders said it may no longer be appropriate to use SEQ market offers to update retail costs,[123] noting that:
  - retail market conditions have evolved such that market offers may no longer consistently reflect underlying efficient retail costs[124]
  - market offers typically reflect customers trading away the higher cost services provided under standard retail contracts in exchange for lower prices, and it is therefore not appropriate for retail costs for notified prices to be derived from market contracts.[125]
- EEQ said there is a need for greater transparency around retail cost components so customers can understand how their choices contribute to retailer costs (e.g. the impact of increasing Australia Post costs when e-billing is readily available).[126] EEQ said greater transparency would also improve confidence that notified prices appropriately reflect the efficient cost of retail service delivery.[127]

Decision

We tested whether the retail cost benchmark should be updated using recent SEQ market data and assessed alternative options suggested by stakeholders.

Benchmarking results

We engaged ACIL to apply the established benchmarking methodology to 2025–26 SEQ market offers.[128]

Under this method, retail costs are derived as a residual – that is, the amount remaining after subtracting the following from observed market offer prices:

- regulated wholesale energy costs
- regulated network costs
- regulated retail-related metering costs.

In principle, this approach should capture changes in underlying cost structures over time, including both cost increases and productivity improvements of the type mentioned by stakeholders.

Applying the methodology to 2025–26 market data produced materially different results to the current benchmark. These outcomes raised questions about whether recent market offers provide a reliable indication of underlying retail costs. In particular:

- the fixed retail costs declined significantly:
  - for small business, from around $214 per customer per year (2021–22 benchmark, expressed in current dollars) to around $47
  - for residential customers, from around $153 to around $63
- there were significant shifts between fixed and variable cost components and wide variation across retailers. In some cases, the implied retail cost was negative.[129]

[123] QCOSS, sub 21, Etrog report pp 8–9; EEQ, sub 18, p 1.
[124] QCOSS, sub 21, Etrog report pp 8–9.
[125] EEQ, sub 4, p 7.
[126] EEQ, sub 4, p 7, sub 18, p 1.
[127] EEQ, sub 18, p 1.
[128] See ACIL Allen, *2026–27 notified prices review: retail costs update*, final report, prepared for the QCA, May 2026. ACIL's retail costs report is available on our website.
[129] ACIL's retail costs report, p. 18.

As retail costs are derived as the residual from observed market offers, the results are sensitive to assumptions and cost inputs used in the calculation. For example, regulated metering allowances and wholesale energy costs may differ from the costs faced by individual retailers in SEQ. More broadly, differences between the way retailers recover costs in competitive offers and the way costs are represented in the regulatory framework may materially affect the residual estimate. This includes differences in the allocation of costs between fixed and variable components.

Differences between regulated metering allowances and the way metering costs are recovered in market offers may explain some of the movement in fixed retail costs. However, materially lower small business retail costs remain even when metering is excluded, suggesting metering alone does not explain the outcomes.

Retail operating costs are typically incurred on a per-customer basis and do not vary significantly with energy usage. As a result, retail cost structures are generally expected to be predominantly fixed. Large reductions in fixed costs are therefore not consistent with the way these costs are typically incurred and recovered.

SEQ retail market environment and reforms

The benchmarking approach works best where market prices reflect a reasonably consistent recovery of underlying costs. Current market conditions in SEQ suggest this may not be the case.

ACCC analysis shows that pricing in SEQ varies significantly depending on the age of the plan. In SEQ:

- customers on plans more than 3 years old pay around 10% (about $213 per year) more than customers on plans less than one year old for similar flat rate offers[130]
- residential customers were quoted average potential savings of around $616 per year, and small business customers around $320 per year, in better-offer messages.[131]

This indicates that retailers maintain materially different price levels within their customer portfolios.

ACCC data also shows that acquisition-style offers in SEQ tend to move closely with the DMO and are typically positioned below the DMO cap. This suggests that competitive pricing may be influenced by positioning relative to the DMO cap.

In this environment, newer competitive offers – which form the basis of benchmarking – may reflect customer acquisition strategies and portfolio segmentation, rather than a consistent recovery of efficient retail operating costs across all customers.

Relevantly, there are significant reforms underway expected to broadly impact pricing dynamics across the NEM and in SEQ. From 1 July 2026, new rule changes are expected to reduce loyalty penalties and narrow the spread of prices across customers. These changes include:

- preventing customers coming off fixed-term contracts from being charged more than the standing offer price[132]
- removing certain conditional discount structures on older plans[133]
- implementing the broader DMO reforms, which will impact pricing in SEQ (see section 5.1 for information on the DMO reforms and impacts for our review).

[130] ACCC, *Inquiry into the National Electricity Market*, final report, December 2025, p 32 (Figure 3.8).
[131] ACCC, *Inquiry into the National Electricity Market*, final report, December 2025, Table 3.3.
[132] AEMC, *Improving consumer confidence in retail energy plans*, rule determination, June 2025.
[133] AEMC, *Improving consumer confidence in retail energy plans*, rule determination, June 2025.

Overall, these reforms are designed to reduce the prevalence of higher-priced legacy plans and move more customers onto lower-priced offers.

Given these changes, current market pricing patterns may not reflect how retailers will recover their costs and the market offers available in SEQ during 2026–27, once the reforms take effect.

Option assessment

In considering whether to update the retail cost benchmark for 2026–27, we assessed the reliability of benchmarking outcomes, the appropriateness of alternative approaches raised by stakeholders and practical considerations relevant to this review.

Updating the benchmark would align retail cost allowances with recent SEQ market offers. However, given the significant volatility observed in the benchmarking results, the sensitivity of the residual methodology and the evidence of material pricing differences in SEQ, we consider updating the benchmark this year risks embedding short-term pricing dynamics into notified prices.

Some stakeholders said we should independently estimate retail costs using a bottom-up approach. However, we do not consider this to be appropriate or practical for this review because:

- the AER already undertakes a comprehensive assessment of retail costs as part of its DMO determination, using detailed retailer data obtained through its information-gathering powers. Replicating this exercise would duplicate an existing regulatory process and would be difficult within our review timeframe, particularly given we do not have equivalent powers to obtain detailed retailer information. A comparable process would therefore impose additional administrative burden on both the QCA and retailers and would be unlikely to improve regulatory outcomes
- the timing of the DMO determination relative to our review means it is not practical to undertake a comparable bottom-up assessment or adopt the AER's retail cost estimates within this review cycle
- notified prices in regional Queensland are capped at the DMO. This means that even if our cost build-up would otherwise result in higher prices, the DMO operates as a binding constraint (see section 5.1).

We also consider it appropriate to continue using the RBA's CPI forecasts to update the fixed retail cost component. While individual cost components may move differently over time, the RBA's latest forecasts reflect current economic conditions and provide a transparent and established basis for maintaining benchmark costs in real terms.

We recognise that differences may exist between market and standard retail contract arrangements. However, the existence of these differences does not in itself mean that market observations are inappropriate. The benchmarking method uses flat-rate SEQ market offers as a proxy for efficient retail costs and does not rely on more complex or highly differentiated products. In addition, for small customers, the notified pricing framework includes a standing offer adjustment (SOA), which recognises the additional value associated with standard contract terms and conditions.

Taken together, we consider the broader framework appropriately accounts for differences between market and standard contract arrangements. However, as discussed above, the issue in this review is not the broader framework itself, but that recent SEQ market data does not currently provide a sufficiently reliable basis for estimating retail costs. We will continue to review the benchmark and reassess the suitability of market data in future reviews, particularly as recent reforms are implemented and pricing behaviour evolves.

Finally, we do not consider the level of transparency suggested by EEQ is practicable within the benchmarking framework, which estimates retail costs at an aggregate level rather than separately identifying individual cost items, such as paper billing or postage costs. To the extent retailers wish to provide greater transparency regarding service choices and associated costs, these matters are more appropriately addressed through retailer-led customer engagement initiatives.

Decision

On balance, we consider the summary of benchmarking results previously presented suggests either a fundamental change in pricing dynamics or sensitivities of the benchmarking methodology. Therefore, we do not consider it is appropriate to rely on the outcomes from the 2025–26 data.

We consider a more prudent approach under these circumstances is to retain the existing retail cost benchmarks for 2026–27. Informing this view is that rule changes and reform activities that are underway – especially the DMO reforms – are likely to have implications for retailer behaviour in the market and affect market offers during this time.

Table 4.4 sets out the basis for determining retail cost allowances this year for small customers.

Table 4.4: Basis for determining retail cost allowances for small customers

Customer type	Basis
Small customers	Apply established benchmark costs (based on the costs of supply in SEQ) by: 1. adjusting last year's fixed retail costs[a] for inflation[b] (to maintain fixed costs in real terms) 2. maintaining the variable retail cost allocators at: 3. 7.25% for residential customers 4. 18.70% for small business customers.

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 2.4% for the financial year ending June 2027. See RBA, *Statement on Monetary Policy*, May 2026.

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 due to the difference between forecasted and actual deployment of ADMs in the previous year.

ADM costs

We have set retail metering service costs for ADMs using a similar approach to last year's notified prices review. Specifically, we apply the average cost incurred per ADM in SEQ to the forecast deployment of smart meters in the Ergon distribution region. This approach ensures customers in regional Queensland pay no more than customers in SEQ for metering services, consistent with the UTP.[134]

EEQ raised concerns with our approach to determining small customer ADM costs:

[134] We note that, consistent with last year, the costs of ADMs are the only costs captured here, with costs for standard (accumulation) meters included in network prices since 1 July 2025. See AER, *Energex Electricity Distribution Determination 2025 to 2030: Overview*, final decision, April 2025, p 31.

- Reliance on AER metering cost estimates – EEQ said the AER's DMO methodology understates efficient metering costs (by dividing total ADM costs by the number of smart meter customers at the end of the cost reporting period), which understates the average cost per ADM and results in an under-recovery of metering costs.
- Application of the UTP – EEQ said our approach misapplies the UTP by directly incorporating SEQ ADM costs in regional tariffs, rather than first determining the actual cost of delivering metering services in regional Queensland.
- Role of the SOA and delegation requirements – EEQ said where regional metering costs exceed SEQ costs and would otherwise result in notified prices exceeding the DMO, the difference should be addressed through the SOA. EEQ considered this approach would better reflect the operation of the DMO as a pricing cap, improve transparency, and better align with the ministerial delegation and intent of the UTP.[135]

Based on the most recent AER advice, the average cost per ADM in SEQ is calculated by:[136]

- determining the sum of total metering costs in each distribution region, disaggregated by customer type and DNSP, for the most recent full year dataset (2024–2025)
- determining the total number of ADMs deployed to customers in the region as at the end of the reporting period (30 June 2025)
- calculating average unit costs by dividing total ADM costs by total ADM customer numbers in each region.[137]

The AER's method relies on information provided by SEQ retailers and ADM deployment to determine a customer-weighted smart meter allowance in distribution regions. This is not intended to replicate how an individual retailer incurs or recovers its metering costs. Rather, the AER values reflect an efficient cost for retailers operating in a competitive market in SEQ.[138]

Consistent with our broader approach to notified prices, we have relied on the AER's published metering cost estimates in determining small customer ADM costs. As for network costs and other cost inputs used in the notified pricing framework, we do not reassess or independently re-estimate cost values already determined through established regulatory processes unless there is evidence that those estimates are unreasonable or inappropriate for the purpose for which we use them. There is no evidence before us that the AER's ADM cost estimates are unreasonable or inappropriate to use as a cost benchmark for notified prices.

We consider our approach is consistent with the UTP and the ministerial delegation. Under the UTP, regional customers of the same class should pay no more than customers in SEQ for comparable electricity services. Consistent with this objective, small customer notified prices generally reflect benchmark costs and outcomes in SEQ. The delegation specifically directs us to use costs incurred by retailers operating in the Energex distribution area for small customer ADM services, with regional information incorporated through ADM deployment levels.[139]

The delegation does not require us to first determine the actual cost of providing metering services in regional Queensland, before applying UTP outcomes. As with other components of the N+R methodology, ADM costs are not intended to estimate Ergon Retail's actual cost of supply in regional Queensland. Rather, they are intended to reflect the costs of supply in SEQ, with any difference addressed through the CSO framework.

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[135] EEQ, sub 4, pp 3–5, sub 18, p 2.
[136] Our draft determination noted that the AER collects retailers' absolute dollar costs by category (including smart meters) and their average customer numbers over the reporting period.
[137] Australian Energy Regulator, *Default market offer 2026–27*, final determination, May 2026, pp 58, 68, 103–105.
[138] Australian Energy Regulator, *Default market offer 2026–27*, final determination, May 2026, p 58, 68.
[139] Ministerial delegation, cl 2(d) (i)–(ii).

Given this, we do not agree that differences between regional and SEQ metering costs should be reconciled through the SOA. The SOA reflects the differences in benefits to customers and costs to retailers associated with standard contracts relative to market contracts. While reductions in the SOA may also be used as a practical mechanism to implement DMO pricing constraints, neither the SOA nor DMO adjustments are intended to reconcile differences between individual regional and SEQ cost inputs, including metering costs.

True-up mechanism

We include a true-up mechanism for metering costs to reconcile any over- or under- recovery from the previous year.

This process involves:

1. comparing retail metering service costs based on actual ADM deployment in 2025–26 with the allowance included in current notified prices (which is based on forecast deployment)[140]
2. adjusting any under- or over-recovery identified in step 1 for timing differences to determine the pass-through amount for 2026–27 notified prices.

Based on our assessment, we estimated an over-recovery of retail metering service costs in 2025–26. This reflects a lower actual ADM deployment rate (69.20%[141]) than forecast (70.55%). After adjusting for timing differences, we estimate an over-recovery of 0.355 c/day, which is passed through to customers by reducing metering costs in 2026–27.

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.

[140] As the costs are based on mid-year deployment forecasts, we use the actual deployment (as at December 2025) to calculate the actual metering costs used in this comparison. A lower actual mid-year deployment rate means lower smart metering costs should have been included in 2025–26 notified prices.

[141] 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: ADM costs for small customer tariffs, 2026–27 (excl GST)

Description	Metering costs (c/day)	Approach
Primary tariff	24.367[142]	To calculate the base metering cost, we used: 1. relevant ADM metering costs to apply in SEQ, published by the AER[a] 2. the forecast deployment rate of ADMs for small customers in regional Queensland for 2026–27, as provided by EEQ.
True-up adjustment	–0.355	To estimate the over- recovery of metering costs we: 3. calculated the difference between retail metering costs based on forecast ADM deployment (70.55%) and actual ADM deployment (69.20%) 4. adjusted the over-recovery for timing differences using the weighted average cost of capital (9.20%).
Overall charge	24.012	Retail metering costs, including the true-up adjustment.

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 2026-27,* final determination, May 2026.

Retail charge for manually reading a type 4A meter

There are additional costs associated with manually reading meters where customers choose to disable the remote communication functionality of an ADM.

We have been asked to consider setting a series of retail charges based on EEQ'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.

EEQ said that the costs of manually reading type 4A meters are rising due to a small and geographically dispersed fleet and customer base. EEQ proposed introducing a daily charge of $0.72 for customers who disable meter communications and estimated an average additional annual cost of $232.48 per customer. EEQ noted that customers can avoid the charge by re-enabling communications.

At this time, we consider it appropriate to continue using the AER-approved special meter read fee for Ergon Energy, pending further information from EEQ.[143] In the absence of this information, we cannot properly assess whether EEQ's proposed charge is reasonable, compared to our current benchmark rate.

Consistent with this approach, we have adopted the AER-approved special meter read fee for Ergon Energy in 2026–27 of $51.56.[144]

4.2.3 Retail costs – large customers

We periodically review the benchmark retail cost allowances for large business customers to ensure they remain appropriate and reflect current retail operating conditions. The most recent review

[142] This equates to around $89 per customer in 2026–27. Note, with true-up adjustment included, the overall charge equates to around $87.65 per customer in 2026–27.
[143] Ergon Retail has previously advised that information on costs by feeder type is not available.
[144] Ergon Energy Queensland, *2026–27 Network price list*, May 2025, accessed 20 May 2026.

occurred as part of the 2021–22 notified prices determination, when the existing benchmark was retained.

As part of this review, we considered whether new allowances should be established for large and very large business customers. However, due to the data quality issues identified below, we have maintained our existing approach – that is, we have set the retail cost allowances using the established benchmark, adjusted for inflation.

Benchmarking results

We engaged ACIL Allen to review the existing benchmark using information obtained from retailers operating in the Ergon Distribution region. This included information on the retail costs incurred in supplying large and very large customers during 2025–26. Further information on the data and ACIL Allen's approach is provided in its report published with this determination.

We received confidential data from 12 retailers – 9 relating to large customers and 7 relating to very large customers. While this represents a higher response rate than in previous reviews, reported retail costs varied significantly across retailers, and 2 outliers in each category were excluded from the analysis.

Retailers also reported costs using different structures, with some identifying fixed and variable components but others reporting only one component (or they were unable to clearly separate cost drivers). In terms of expected cost movements, 5 retailers indicated their costs are likely to remain broadly unchanged between 2025–26 and 2026–27 (with one suggesting costs may be slightly lower), while 3 retailers expected costs to increase over this period.

ACIL noted that there is some subjectivity in the reported data, as retailers do not necessarily collect cost information in the form requested. The retail cost allowances approved in our 2025–26 determination fall within the range of estimates provided, although towards the upper end. On this basis, ACIL Allen considers that the existing benchmark retail cost allowances could reasonably be maintained in nominal terms until the next review.

Decision

On balance, we consider there is insufficient evidence to suggest that the retail cost allowances for large and very large business customers in 2026–27 will be materially different from those allowed in 2025–26.

While we have obtained more data than in previous reviews, the variability in reported costs and differences in cost structures mean the benchmarking results do not provide a sufficiently robust basis to replace the existing benchmark.

Table 4.6 sets out the basis for determining retail cost allowances this year.

Table 4.6: Basis for determining retail cost allowances for large and very large customers

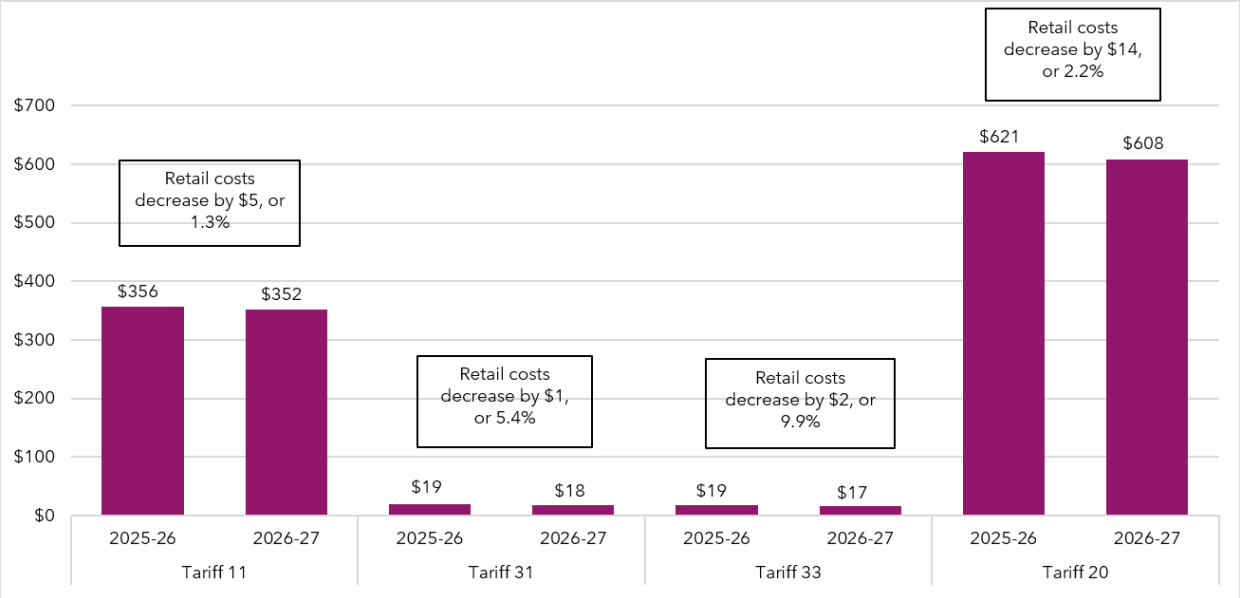
Customer type	Basis
Large customers	Apply established benchmark costs (based on the costs of supplying large customers) by: • adjusting last year's fixed retail costs[a] for inflation[b] to maintain fixed costs in real terms • maintaining the variable retail cost allocators at 6.0445%.

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 2.4% for the financial year ending June 2027. See RBA, *Statement on Monetary Policy*, May 2026.

Retail costs included in notified prices

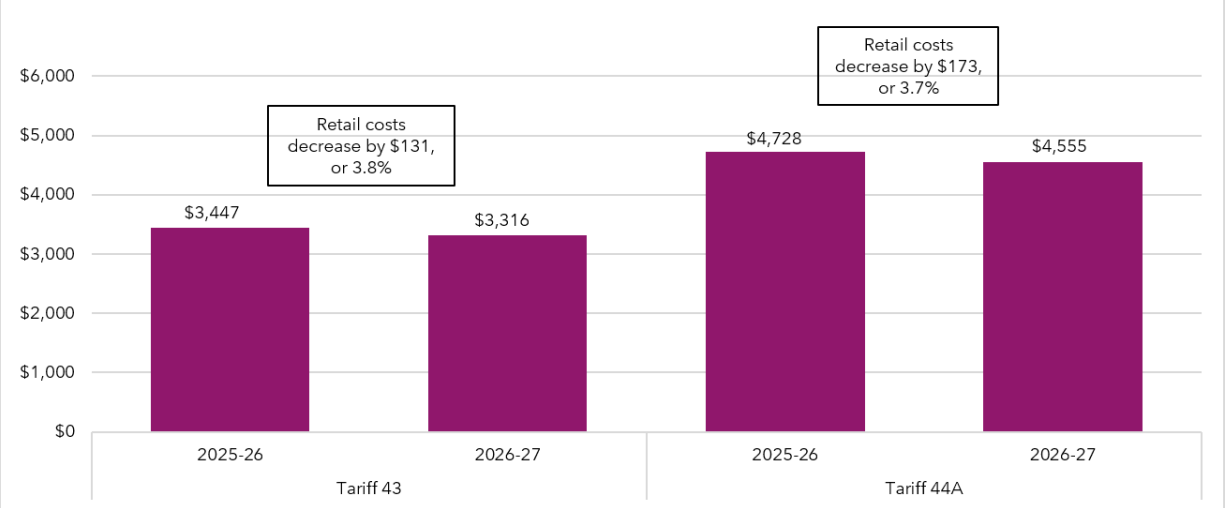
Overall, retail costs have not changed substantially (in dollar terms) compared to 2025–26, with small and large customers experiencing small decreases.[145] The change to the annual bill for a typical small and large customer is set out in Figures 4.5 and 4.6.

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



Note: 1. Bill changes (dollar amounts) are rounded. 2. Percentage changes are based on unrounded amounts.

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



Note: 1. Bill changes (dollar amounts) are rounded. 2. Percentage changes are based on unrounded amounts.

[145] Fixed retail costs increase (due to inflation) for all customers. Variable retail costs are calculated as a percentage of total (variable) network and energy costs, so changes in these components affect variable retail costs. As a general observation for this year, energy costs have decreased by more than network costs have increased, which reduces *variable* retail costs. For most customers, this reduction in variable retail costs is sufficiently large to decrease retail costs overall, relative to 2025–26.

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 to reflect the value of more favourable terms and conditions in standard contracts, relative to market contracts.

We estimate the SOA using an established method that draws on SEQ retail market information to assess the costs associated with market contracts (e.g. the fees and charges a typical SEQ customer may incur).[146] This market data acts as a proxy for estimating the value of standard contract terms for customers in regional Queensland, specifically, the fees and charges they can avoid under these arrangements.

Using 2024–25 SEQ market data,[147] we:

- assessed the range of fees and charges included in SEQ retail market contracts
- identified additional fees that apply under retail market contracts but not standard contracts
- estimated the average additional costs that small customers in SEQ may incur when on market contracts.[148]

Stakeholder comments

QCOSS raised concerns regarding the role and estimation of the SOA. It said:

- Customer value and methodology – there is insufficient evidence that customers value, or are willing to pay for, the services reflected in the SOA. It said retailer charges for optional services are not an appropriate proxy for the value customers place on standard contract terms and said the value of these terms can only be determined by customers themselves. QCOSS also considered the current approach lacks transparency.
- Future role of the SOA – the SOA should be removed from future notified prices and there is no basis in the delegation.
- Consistency with the UTP – the SOA is inconsistent with the intent of the UTP because, prior to any DMO adjustment, it increases costs for regional customers relative to customers of the same class in SEQ.[149]

[146] The method we use was established as part of the 2021–22 notified prices review.
[147] This data reflects our most recent review of retail fees in SEQ (QCA, *SEQ retail electricity market monitoring 2024–25*, December 2025, pp 38–54).
[148] The typical annual bill for small customers is based on June 2025 data from Appendix A of the QCA's *SEQ retail electricity market monitoring report 2024–25: Appendices*, December 2025.
[149] QCOSS, sub 10, Etrog report, p 10, sub 21, p 3, Etrog report, pp 5–6.

Decision

While the delegation does not explicitly refer to the SOA, this does not preclude us from including it as part of the notified prices methodology. The SOA has been a longstanding component of the notified prices methodology and reflects the value of terms and conditions available under standard retail contracts, relative to market contracts. This is relevant because elements of the notified prices methodology draw on market information from SEQ, where customers are typically supplied under market contracts (compared to customers on notified prices in regional Queensland, who are supplied under standard contracts).

Importantly, the SOA does not attempt to measure the value customers themselves place on standard contract terms and conditions, which may vary across customers and may in some cases be zero. Instead, it reflects the value retailers place on these terms, as evidenced by the fees and charges applied under market contracts when customers do not comply with certain contract conditions. We do not consider these charges are being used as a proxy for customer preferences. Rather, they provide observable market evidence of the costs retailers associate with removing or relaxing these conditions. As such, it is appropriate to recognise differences in the terms and conditions available under standard and market contracts.

Based on our assessment of 2024–25 market data, small customers on market contracts in SEQ can incur additional fees of, on average, $54.18 per year, equivalent to around 3.09% of a typical small customer's annual bill.

Accordingly, we consider a SOA of 3.09% (of total costs) is appropriate for inclusion in small customer notified prices. The SOA has decreased slightly from 3.35% in the 2025–26 determination.

The SOA is incorporated into notified prices before we undertake the DMO comparison, which is a separate step in our methodology to ensure final notified prices comply with the requirements of the UTP (discussed further in Chapter 3).

5.1.1 DMO comparison

The AER sets a DMO for standing offers in particular jurisdictions, including SEQ. The regulatory framework for the DMO has recently been reformed by the Australian Government, which will result in changes to the way in which the AER sets the DMO. Key elements of the DMO reforms are summarised in Box 6.

The delegation requires us to treat the SEQ DMO as a cap, with standard flat-rate tariffs in regional Queensland to be set no higher than the equivalent SEQ DMO. It also states that a negative SOA may be applied if necessary to achieve the Queensland Government's UTP. When applying any SOA adjustment, tariff relativity for more complex small customer tariffs must be maintained.

This year, the Minister has also flagged the reforms and potential for changes to the DMO that could allow the DMO comparison to be based on tariff rates (i.e. the usage charge and fixed daily supply charge), rather than based on a reference bill, as has been done in the past. However, the Minister has indicated a preference for maintaining the existing approach to the DMO comparison but asked us to consult with stakeholders on the merits of each approach.

Box 6: Summary of DMO and recent reforms

- **DMO introduced (2019):** The Australian Government introduced the DMO as a safety-net price cap for standing offers for residential and small business customers in New South Wales, South Australia and SEQ, and as a reference price to help customers compare market offers.
- **Current role:** The DMO is set annually by the AER and represents the maximum price retailers can charge customers on standing offers in these regions.
- **DMO reforms announced (2025):** The Australian Government announced reforms to the DMO with the objective of strengthening consumer protections and ensuring the price cap reflects the efficient cost of supplying electricity:
  - **Efficient cost focus** – the DMO will be more explicitly based on the efficient cost of supplying electricity to customers.
  - **Reduced discretionary allowances** – the reforms reduce discretionary retail allowances (such as headroom) that were originally included to support retail competition.
  - **Tariff-level caps** – the DMO framework will move from relying primarily on a reference annual bill to setting caps on individual tariff components.
  - **Solar sharer offer** – retailers will be required to offer a new 'solar sharer' style tariff designed to encourage electricity use during periods of high solar generation (see section 3.2).
  - **Expanded consumer protections** – the reforms extend protections to additional customer groups.
- **Regulatory changes:** The DMO regulations were amended in March 2026 to implement these reforms (reflected in the AER's DMO determination).

Stakeholder comments

QCOSS said we should continue to adopt the usual approach to setting notified prices, rather than using the DMO tariffs directly in the Ergon Energy area. It said that among other reasons, the DMO is designed where there is effective competition, which is not the case in regional Queensland.[150]

Decision

Consistent with the Minister's preference, and noting the limited stakeholder feedback received, we have maintained our existing approach of basing the DMO comparison (and potential adjustments to notified prices) on reference bills rather than making a direct comparison of tariff rates.

It would be possible to align notified prices directly with those set for the SEQ DMO. The AER now sets tariff-level caps as part of the DMO framework and, in principle, these tariffs could be adopted in regional Queensland. However, doing so would represent a significant change to the current notified price framework. While it may reduce some duplication between the AER and QCA processes, some regulatory work would still be required. For example, for retail tariffs in regional

[150] QCOSS, sub 10, pp 4–5.

Queensland that do not have direct equivalents in SEQ, prices would still need to be calculated and set under the notified price framework.

The current approach has also been used for a number of years and provides a stable and transparent method for ensuring notified prices do not exceed the SEQ DMO cap, while explaining the cost drivers affecting electricity prices in regional Queensland.

To enable a comparison of the SEQ DMO with notified prices, we undertook the following steps:

- **DMO reference bills:** we converted the relevant SEQ flat tariff prices (tariff 11, tariff 11 with controlled load, and tariff 20) into reference bills using the consumption estimates published by the AER.
- **Adjustments for a like-for-like comparison**: to ensure a consistent comparison between notified prices and the DMO:
  - we account for GST differences for the purposes of the comparison. DMO reference prices include GST, whereas notified prices exclude GST
  - we used the DMO consumption levels to calculate comparable notified price bills, as the consumption levels used for the DMO differ from those used in our typical customer calculations.[151]
- **Bill comparison:** we compared the relevant DMO reference bills (using the tariff rates and consumption levels published by the AER) to the notified price bills (where the notified price bills include the 3.09% SOA).

The results of this comparison are shown in Table 5.1, which presents the relevant DMO reference bills alongside the comparable notified price bills (including the SOA). Based on this comparison, we found that notified price bills exceeded the equivalent DMO reference bills this year.

Accordingly, we consider it appropriate to discount the SOA included in small customer notified prices to ensure notified price bills do not exceed the relevant DMO reference bills. We propose to adjust the 3.09% SOA to:

- –1.74% for all residential customer tariffs
- –2.14% for secondary load control tariffs
- –10.69% for all small business customer tariffs.

Applying the same adjustment to all tariffs within each customer class ensures that tariff relativity is maintained and avoids creating incentives for customers to switch tariffs purely due to changes in relative price levels.

[151] As of DMO 8, the AER no longer publishes a bill for the primary flat rate residential tariff when it is combined with secondary load control tariffs (tariff 11 plus a weighted average of tariffs 31 and 33). For comparison, we constructed a combined bill using the current DMO load control consumption level and the flat rate consumption level previously used in DMOs for combined tariffs.

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

Customer type	Relevant notified price tariff	DMO reference bill (A)	Notified price bill (incl 3.09% SOA) (B)	Difference (B – A)	Notified price bill (adjusted SOA) (C)	Difference (C – A)
Residential	11	$1,988	$2,086	$98	$1,988	$0
	11+ 31, 33[a]	$2,248	$2,360	$112	$2,248	$0
Small business	20	$3,849	$4,443	$594	$3,849	$0

a Uses consumption for the primary residential flat-rate tariff, based on the combined profile published by the AER in DMOs prior to DMO 8.

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 SRES liabilities for each calendar year, while notified prices are set for each financial year.

As a result, at the time we make our final determination for notified prices, the 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.[152] If the CER's final determination of SRES liabilities differs from its earlier forecast, this can lead to an over- or under-recovery of SRES costs in notified prices.

For 2025–26, there was an over-recovery of SRES costs, as the final SRES liabilities determined by the CER were lower than the forecast used in our final determination of prices for 2025–26 (therefore, retailers were required to purchase fewer certificates than originally forecast).[153]

We treat this over-recovery as a cost pass-through in notified prices, which reduces usage charges for all retail tariffs in 2026–27.[154]

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

5.3 Metering costs – large customers

Consistent with our approach in previous determinations, we estimated large customer ADM costs for 2026–27 using confidential data provided by Energy Queensland for each large customer type.

The metering charges for large customers are set out in Chapter 6.[155]

EEQ said this approach does not fully reflect differences in metering costs between customers because it is based on a representative consumption level of 750 MWh. EEQ recommended that

[8]The CER typically determines the final SRES liabilities for the second half of the financial year around 9 months after our final determination.

[153] Reflecting the CER's final SRES liabilities for calendar years 2025 and 2026. See Clean Energy Regulator, *Small-scale technology percentage*, CER website, 2026, accessed 2 March 2026.

[154] Cost pass-through mechanisms are commonly used by regulators to manage the risk that forecast costs in regulated prices differ from the efficient costs of supply. These mechanisms are typically limited to events outside the control of the regulated entity, such as SRES liabilities. See Appendix B for further detail on how the SRES cost pass-through is calculated.

[155] Metering charges for large customers are identified separately. In contrast, small customer metering costs are incorporated into the relevant retail tariffs.

metering charges instead be based on meter type (types 1–4) and suggested implementing such an approach from 2027–28.[156]

We have retained the current approach for the 2026–27 determination. However, as part of the next review, we will assess whether large customer metering costs could be set in a more cost-reflective manner, including the approach proposed by EEQ, taking into account the information available at that time.

5.4 Default retail tariff arrangements

Under the retail tariff schedule, default tariff arrangements apply where a small customer does not nominate a tariff when they become a standard contract customer of a retailer. In these circumstances, the retailer must assign the customer to tariff 11 (for residential customers) or tariff 20 (for small business customers).[157] Importantly, these arrangements do not prevent customers from subsequently requesting assignment to another tariff.[158]

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

Subject to stakeholder submissions, and consistent with our views in previous determinations, we consider there is merit in retaining the default tariff arrangements. These arrangements provide customers with certainty about the tariff they will be assigned if they do not nominate one. This is particularly important where a customer is deemed to have entered a standard retail contract with a retailer.[159]

5.5 Additional issues raised by stakeholders

Stakeholders commented on a range of matters not addressed elsewhere in this report. Their comments and our responses are summarised in Table 5.2.

Table 5.2: Additional issues raised by stakeholders

Stakeholder comment	QCA response
Stakeholders raised issues relating to the CSO, including that: • the CSO should be embedded in network charges instead of retail prices[160] • a targeted CSO should be applied to the daily supply charge for tariff 60A, as this tariff component is a 'major disincentive' to the uptake of controlled load by irrigators.[161]	The design of the CSO, including how it is delivered, is a policy decision made by the Queensland Government. Stakeholders wishing to raise concerns about the CSO arrangements should therefore direct these matters to the Queensland Government. Tariff 60A is a primary tariff that attracts a daily supply charge representing the fixed costs for the tariff, which largely comprises the network cost component. Application of a targeted CSO to

[156] EEQ, sub 4, pp 6–7.
[157] 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.
[158] Queensland Government, *Gazette: Extraordinary*, no 28, vol 399, 6 June 2025, tariff schedule, p 227.
[159] 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 the *National Energy Retail Law (Queensland)*, ss 54–55 and the National Energy Retail Rules, div 8. A customer may be transferred to a designated retailer of last resort if their retailer becomes insolvent or has its authorisation is revoked.
[160] Canegrowers, sub 1, p 8; QFF sub 22, p 9.
[161] QFF, sub 22, p 8.

Stakeholder comment	QCA response
	lower the daily supply charge for this tariff (beyond application of the UTP) is a matter for government and should be directly raised with the Minister.
QCAR raised concerns that: • greater transparency should be provided on how we weigh the matters in section 26(1) of the QCA Act in our assessment, particularly regarding the rising groundwater problem in the Burdekin region[162] • pricing reviews should occur more frequently to reduce shocks from large price adjustments.[163]	The matters in section 26 of the QCA Act apply to our prices oversight regime under part 3 of the QCA Act, rather than the determination of notified prices under the Electricity Act. Matters such as groundwater management in the Burdekin region fall outside the scope of this review. Determinations of notified prices already occur regularly (annually), and sometimes more frequently where new tariffs are introduced.
QFF said there should be a mechanism to enable a customer reclassified as a large customer to request a reassessment and be reclassified as a small customer, including based on quarterly bills rather than after an annual period.[164]	The circumstances in which a customer can be reclassified between tariff classes are set out in EEN's approved tariff structure statement.[165] In accordance with the N+R framework for our determination (Chapter 3), we would not introduce alternative arrangements, noting this could potentially result in a difference between the customer class of a customer at the retail and network level.
QCOSS recommended that we provide advice to the Queensland Government regarding the need for energy literacy programs to assist households to understand the tariff choices available to them. It stated QCOSS has made a pre-budget submission on increased funding for various energy literacy programs.[166]	As funding for these programs is a matter for the Queensland Government, we encourage QCOSS to raise these matters directly with the Minister.

[162] QCAR, sub 8, pp 2–3.
[163] QCAR, sub 8, p 5.
[164] QFF, sub 12, p 5, sub 22, p 6.
[165] Ergon Energy Network, *Tariff Structure Statement: In support of the Regulatory Determination Proposal 2025–26*, November 2024, as amended and approved by the AER April 2025, pp 39–40, 67–68.
[166] QCOSS, sub 21, p 4.

6 Notified prices

Table 6.1: Residential and small business customers (excl GST), 2026–27

Retail tariff	Fixed[a] (c/day)	Usage			Peak demand ($/kW/mth)
		Off-peak/ flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)	
Tariff 11 – residential (flat-rate)	164.098	26.268			
Tariff 12D – residential time-of-use[b]	142.482	16.829	22.767	36.955	
Tariff 12E – residential time-of-use[b]	142.482	6.367	23.266	42.915	
Tariff 14C – residential time-of-use demand[b,c]	122.831	16.829	22.767	19.041	7.377
Tariff 20 – small business (flat-rate)	194.944	27.875			
Tariff 22D – time-of-use[d]	194.676	18.194	24.626	44.368	
Tariff 22E – time- of-use[d]	194.676	7.496	24.167	52.117	
Tariff 24C – time-of-use demand[d,e]	162.704	18.194	25.183	18.926	7.421

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 Demand – 4 pm to 9 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 Demand – 5 pm to 8 pm weekdays.

Table 6.2: Small customer interruptible supply and unmetered tariff (excl GST), 2026–27

Retail tariff	Fixed[a] (c/day)	Usage Off-peak/ flat (c/kWh)
Tariff 31 – night rate (super economy)		15.148
Tariff 33 – controlled supply (economy)		15.240
Tariff 34 – small business interruptible supply	162.704	20.087
Tariff 91 – small business (unmetered)		25.927

a Charged per metering point.

Table 6.3: Large business customers (excl GST), 2026–27

Retail tariff	Fixed (c/day)	Usage[a] (c/kWh)	
		Below threshold	Above threshold
Tariff 43 – Business customer (over 100 MWh)	6149.745	18.960	16.786

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

Table 6.4: Large business customers (excl GST), 2026–27

Retail tariff	Fixed	Usage			Demand					
		Off-peak/flat	Shoulder	Peak	Off-peak/ flat	Shoulder	Peak	Off-peak/flat	Shoulder	Peak
	(c/day)	(c/kWh)			($/kVA/mth)			($/kW/mth)		
Tariff 44A – over 100 MWh small (demand)	6149.745	17.167			23.179					
Tariff 49 – time-of-use energy[a]	27310.766	17.176	33.982	40.506						
Tariff 50B – time-of-use demand[a,b]	5760.566	17.176	17.984	40.506		5.972	14.337		6.636	15.930
Tariff 50C – time-of-use demand[a,b]	5760.566	9.343	17.885	48.401		5.972	14.337		6.636	15.930
Tariff 60A – interruptible supply (primary)	5417.345	20.110								
Tariff 60B – interruptible supply (secondary)		20.110								
Tariff 71 – street lighting		32.224								

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.
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.

Table 6.5 Very large business customers (excl GST), 2026–27

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)	27496.033	14.309	7.914	3.545	4.636
Tariff 51B – high voltage (CAC 33 kV)	18088.533	14.309	7.914	4.583	4.794
Tariff 51C – high voltage (CAC 22/11 kV Bus)	15479.133	14.309	7.914	4.467	5.892
Tariff 51D – high voltage (CAC 22/11 kV Line)	14542.533	14.309	7.914	9.098	11.762
Tariff 53 – high voltage (ICC)	27277.583	14.309		3.545	4.636
ICC site-specific – high voltage	2946.183	11.412		0.202	0.264

Table 6.6 Very large business customers (excl GST), 2026–27

Retail tariff	Fixed	Usage	Connection unit	Demand		
		Off-peak /flat		Shoulder[a]	Peak[a]	
	(c/day)	(c/kWh)	($/day/unit)	($/kVA/ mth)		($/kW/mth)
Tariff 52D – high voltage (CAC 66 kV)	60132.633	12.509	7.914	3.721	6.309	2.403
Tariff 52E – high voltage (CAC 33 kV)	31909.933	12.522	7.914	3.721	6.309	2.403
Tariff 52F – high voltage (CAC HV Bus)	24082.033	12.522	7.914	8.218	13.930	2.403
Tariff 52G – high voltage (CAC HV Line)	21272.333	12.522	7.914	12.174	20.635	2.403

a 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.

Table 6.7 Metering charges large and very large business customers (excl GST), 2026–27

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

Stakeholder submissions and references

We received 22 submissions during this review. They are available on our website.

Stakeholder	Submission number	Date received
Canegrowers	1	13 February 2026
	16	6 May 2026
Caravan Parks Association of Queensland (CPAQ)	2	13 February 2026
Cotton Australia	3	13 February 2026
	17	30 April 2026
Ergon Energy Retail (EEQ)	4	13 February 2026
	18	5 May 2026
Ergon Energy Network & Energex (EEN and Energex)	5	13 February 2026
	19	30 April 2026
Hardwick, B	6	13 February 2026
Horan & Bird Solar	13	9 April 2026
Origin Energy Limited (Origin)	7	13 February 2026
Queensland Cane Agriculture & Renewables (QCAR)	8	13 February 2026
Queensland Consumers' Association	9	13 February 2026
	20	1 May 2026
Queensland Council of Social Service (QCOSS)	10	19 February 2026
	21	6 May 2026
Queensland Energy Users Network (QEUN)	11	12 February 2026
Queensland Farmers' Federation (QFF)	12	13 February 2026
	22	1 May 2026
Queensland Renewable Energy Council (QREC)	14	29 April 2026
Sutcliffe, D	15	5 May 2026

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