Queensland Competition Authority

Technical appendices—Final determination

# Regulated retail electricity prices for 2021–22

**Regional Queensland**

**June 2021**

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# STRUCTURE OF THE TECHNICAL APPENDICES

The technical appendices aim to provide stakeholders with detailed information relevant to setting notified prices this year and should be read in conjunction with the main report.

The technical appendices consist of:

- Appendix A: Minister's delegation
- Appendix B: Stakeholder submissions and references
- Appendix C: Energy cost approach
- Appendix D: Retail cost approach
- Appendix E: Cost pass-through approach
- Appendix F: Default market offer comparison
- Appendix G: Data used to estimate customer impacts
- Appendix H: Build-up of notified prices
- Appendix I: Gazette notice.

# APPENDIX A: MINISTER'S DELEGATION

Queensland Government

Minister for Energy, Renewables and Hydrogen
Minister for Public Works and Procurement

Our Ref: CTS 24465/20

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8 JAN 2021

Professor Flavio Menezes
Chair
Queensland Competition Authority
Level 27, 145 Ann Street
BRISBANE QLD 4000

Dear Professor Menezes

Pursuant to section 90AA of the *Electricity Act 1994* (the Act), I have delegated to the Queensland Competition Authority (QCA) my functions under section 90(1) of the Act for the determination of regulated retail electricity prices in regional Queensland for 2021–22.

The attached delegation and terms of reference for 2021–22 are generally consistent with the approaches of previous delegations, however there are some important additional considerations. Many of these are associated with managing impacts on retail customers of the last of the changes to network tariffs. These changes stem from the Australian Energy Regulator's (AER) 2020-25 Tariff Structure Statement decisions for Queensland's electricity distributors. A balance between the continued advancement of network tariff reform and positive retail customer experience is essential.

The government's uniform tariff policy (UTP) and costs to consumers are important considerations when setting regulated retail electricity prices in regional Queensland. The delegation and terms of reference maintain this long-standing policy. Consistent with the arrangements in 2020-21, this includes a requirement to adjust for the additional value provided by standard contracts compared to market contracts, while also ensuring that the Default Market Offers set by the AER for south east Queensland act as a ceiling on regional prices. The QCA should again consider including an adjustment similar to that applied in 2020-21 that appropriately reflects this additional value.

In consideration of outcomes for customers, it is important to differentiate retail tariffs from network tariffs and there are some elements of the delegation which provide policy guidance in this regard.

Network tariff reform should be progressed, but it should not be expected that those reforms be directly mirrored at the retail level as a matter of course. Market retailers will balance the reforms with the expectations and needs of their customers in many different ways and those responses can inform future regulated pricing decisions. While certain terms and conditions are practical at a network level, in many cases they don't make sense in the retail context and if passed through, could have adverse impacts for customers.

- 2 -

Another important policy consideration relates to the equitable pricing of metering services for customers. Under national Power of Choice reforms, all new and replacement meters must be advanced digital meters. I note that the Australian Energy Market Commission has recently opened a review of these arrangements, but the Queensland Government remains concerned about the cost of digital meter services for small customers. In particular the slow progress toward benefit realisation by the electricity supply industry as identified by the QCA in 2019. It is not appropriate that some customers pay more simply because they have an advanced digital meter (ADM). While some customers may initiate actions that result in an ADM being installed, such as installing a solar PV system, upgrading their switchboard to improve its safety, or simply connecting a new house, other customers have their meter replaced because of age or failure. None of these represent genuine customer choice about the meter they have.

Further, and in consideration of the QCA's September 2019 advice to the government on the realisation of benefits from ADM, it is apparent that the current approach to ADM deployment, particularly by the distribution businesses, will likely result in loss of the opportunity to realise most of the value from ADM. While the government is working with Energy Queensland to identify ways to maximise these opportunities, customers should not be expected to foot this shortfall. As such, I consider the appropriate charges for small customer metering services, be they ADM or standard, continue to be those that the AER has approved for Energex's small customer standard metering services. The QCA is to consider those charges as they apply to ADM.

I have also included a number of other matters for the QCA's consideration in the delegation's Terms of Reference.

Public consultation is a vital part of the QCA's process for determining retail electricity prices. In this regard, the terms of reference set out the consultation needs and requires the QCA to publish its draft determination by the end of March 2021 and its final determination by 11 June 2021.

Delivering affordable electricity bills for households and businesses and driving economic recovery in the wake of the COVID-19 pandemic is a core commitment of this government. My department will be available to consult with the QCA on specific wording for the 2021–22 gazette notice and Tariff Schedule, ensuring regional customers continue to benefit from the electricity cost protection provided by the UTP and the benefits of owning our electricity assets.

If you have any questions, [redacted] Executive Director, Policy, Department of Energy and Public Works will be pleased to assist you and can be contacted on telephone [redacted]

Yours sincerely

Mick de Brenni MP
**Minister for Energy, Renewables and Hydrogen**
**Minister for Public Works and Procurement**

**DELEGATION TO QCA**

## DEPARTMENT OF NATURAL RESOURCES, MINES AND ENERGY

***Electricity Act 1994***

## ELECTRICITY (MINISTERIAL – QCA) DELEGATION (NO. 3) 2020

### Power to delegate

1. Under section 90AA(1) of the *Electricity Act 1994* (the Act), the Minister may delegate to the Queensland Competition Authority (QCA) all or any of the Minister's functions under section 90(1) of the Act.

### Powers delegated

2. Subject to the limitations and requirements listed in paragraphs 3 and 4, I delegate the functions of the Minister under section 90(1) of the Act to the QCA.

3. The functions of the Minister specified in paragraph 2 above must only be exercised for the purpose of deciding the prices, or the methodology for fixing the prices, for the tariff year 1 July 2021 to 30 June 2022 that a retail entity may charge its Standard Contract Customers in Queensland, other than Standard Contract Customers in the Energex distribution area.

4. Pursuant to section 90(5)(a)(iii) of the Act, in exercising the functions specified in paragraphs 2 and 3 above, the QCA must have regard to the terms of reference in the schedule.

### Revocation

5. All earlier delegations of the Minister's powers under section 90(1) of the Act are revoked.

6. Unless earlier revoked in writing, this delegation ceases upon gazettal by the QCA of its final price determination on regulated retail electricity tariffs for the 2021–22 tariff year under section 90AB of the Act.

This delegation is made by **The Honourable Mick de Brenni MP**, Minister for Energy, Renewables and Hydrogen:

**Signed:**

The Honourable Mick de Brenni MP
**Minister for Energy, Renewables and Hydrogen**
**Minister for Public Works and Procurement**

**Dated:** 7/1/21

**DELEGATION TO QCA**

## SCHEDULE
## Terms of Reference
## Section 90(5)(a)(iii) and 90AA of the Act

***Period for which the price determinations will apply (section 90AA(3)(a) of the Act)***

1. These Terms of Reference apply for the tariff year 1 July 2021 to 30 June 2022.

***Policies, principles and other matters the QCA must consider when working out the notified prices and making the price determinations (sections 90(5)(a)(iii), 90AA(3)(c) and 90AA(3)(d) of the Act)***

2. The policies, principles and other matters that the QCA is required by this delegation to consider are:

   (a) Uniform Tariff Policy — the Government's Uniform Tariff Policy, which provides that, wherever possible, customers of the same class should pay no more for their electricity, and should be able to pay for their electricity via similar price structures, regardless of their geographic location.

   However, this should not limit Standard Contract Customers outside the Energex distribution area accessing a wider choice of prices and price structures than may be available within the Energex distribution area.

   Additionally, as residential and small business customers paying notified prices are on standard retail contracts, the Government is of the view that the QCA must consider incorporating into notified prices, an appropriate value reflecting the more favourable terms and conditions of standard retail contracts compared to market contracts (**value**). Should the application of this value result in a bill that exceeds an equivalent Default Market Offer as set by the Australian Energy Regulator for southeast Queensland (**DMO**), that value should be discounted so that the resulting bill does not exceed the equivalent DMO. For the avoidance of doubt, if the appropriate value is discounted to zero and the resulting bill is still greater than the equivalent DMO, no further discount should be applied.

   (b) Where one or more tariffs of a type (primary or secondary), within a customer class (residential or small business), is subject to comparison with a DMO and adjustment on the basis described in (a) above, the QCA must consider if it should also discount the value for other tariffs of the type available to the customer class that are not subject to comparison with a DMO. This is intended to maintain pricing relativity and the attractiveness of these tariff options for customers;

**DELEGATION TO QCA**

(c) Making four new retail tariffs based on new network tariffs as approved by the Australian Energy Regulator, including grandfathering arrangements, and as described in EECL 2020-25 Tariff Structure Statement as:

(i) Transitional Network ToU Energy Tariff 1 (small business);
(ii) Transitional Network ToU Energy Tariff 2 (small business);
(iii) Transitional Network ToU Energy Tariff 3 (small business); and
(iv) Business customer (Basic)>100 MWh pa (large business).

To ensure that these tariffs are available to eligible customers across the Ergon network area, do not apply the Australian Energy Regulator's approved geographic limitations of the network tariffs set out in c(i) to (iii) above;

(d) Not making a new retail tariff based on a new network tariff as approved by the Australian Energy Regulator and as described in EECL's 2020-25 Tariff Structure Statement as "Residential customer (Basic)>100 MWh pa" unless such a tariff would, in the view of the Queensland Competition Authority, satisfy a need for the new tariff at the retail level. This will avoid inequitable outcomes for large residential customers based on the type of meter they have and is appropriate given the range of tariffs already available to these customers. If made, the retail tariff should be accessible to eligible customers only on a voluntary basis;

(e) Framework – use of the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by the QCA;

(f) When determining the N components for each regulated retail tariff:

(i) For residential and small business customer Tariffs 11, 20, 31 and 33 - basing the network cost component on the relevant Energex network charges to be levied by Energex and the relevant Energex tariff structures;

(ii) For residential and small business customer Tariffs 12A, 14, 22A and 24, use of a price indexation methodology applied to the N component used in the 2020–21 price determination on the basis that these tariffs no longer have an underlying network tariff;

(iii) For all other residential and small business customer tariffs, except for those set out in f(iv) below - basing the network cost component on the price level of the relevant Energex network charges to be levied by Energex, but utilising the relevant Ergon Energy Corporation Limited (**EECL**) tariff structures, in order to strengthen or enhance the underlying network price signals and encourage customers to switch to time-of-use and demand tariffs and reduce their energy consumption during peak times;

(iv) For the three new retail tariffs associated with the transitional network tariffs set out in c(i) to (iii) above – basing the network cost component on the relevant EECL network charges to be levied by EECL in the 'East distribution pricing zone - Transmission pricing zone T1' to ensure pricing consistency with the application of the Australian Energy Regulator's approved network tariff transition pathway as customers move to more cost reflective tariffs.

(v) For large business retail tariffs for customers who consume 100MWh or more per annum - basing the network cost component on the relevant EECL network charges to be levied by EECL in the 'East distribution pricing zone - Transmission pricing zone T1'.

(g) Retail Operating Costs – undertake a full review of these costs as used in the N plus R framework;

(h) For all existing Standard tariffs as set out in Part 2 of the current Tariff Schedule – maintaining these tariffs including price structures and access criteria unless otherwise set out in this delegation;

(i) Removing the retailer discretion that enables residential customers to access Tariff 33 as a primary tariff, and setting a sunset date by which all existing residential customers accessing Tariff 33 as a primary tariff must be transitioned to a suitable non-interruptible supply primary tariff;

(j) Setting small customer advanced digital metering service charges at the Energex rate for standard Type 6 small customer metering services. This ensures that customers, who do not have any genuine choice as to the type of meter they receive, pay the same regardless of what is installed at their premises;

(k) Default tariffs – maintaining the existing nomination of a primary tariff for each class of small customer to apply to a customer's electricity account in the event the customer does not nominate a primary tariff when opening an electricity account;

(l) Updating the threshold amounts in the definitions of Connection Asset Customer and Individually Calculated Customer to generally reflect the equivalent network tariff thresholds;

(m) The ongoing appropriateness of the discounts applied where supply is given and metered at high voltage and the tariff applied is not a designated high voltage tariff;

(n) Removing expired transitional customer choice provisions on the application of kW and kVA demand charges;

(o) Removing retailer, distributor, metering and other service provider discretions as far as is practicable;

(p) Making the Tariff Schedule as stand-alone as is practicable by specifically including all reasonable and practical, from a retail perspective, network tariff requirements as applicable to each retail tariff, except those subject to other consideration in these Terms of Reference;

(q) Continue enabling retailers to also charge Standard Contract Customers for the following customer retail services that are not included in regulated retail tariffs:

(i) Amounts in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not those additional amounts are calculated on the basis of the customer's electricity usage), but only if:
(a) the customer voluntarily participates in such program or scheme;
(b) the additional amount is payable under the program or scheme; and
(c) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme;

(r) Removing from the Tariff Schedule Ergon Energy Queensland Pty Ltd's EasyPay Reward scheme as this scheme has now ended.

***Consultation Requirements (section 90AA(3)(e) of the Act)***

*Interim Consultation Paper*

3. The QCA must publish an interim consultation paper identifying key issues to be considered when making the price determination.

4. The QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the price determination.

5. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

*Consultation Timetable*

6. The QCA must publish an annual consultation timetable within two weeks after submissions on the interim consultation paper are due, which can be revised at the discretion of the QCA, detailing any proposed additional public papers and workshops that the QCA considers would assist the consultation process.

*Workshops and Additional Consultation*

7. As part of the interim consultation paper and in consideration of submissions in response to the interim consultation paper, the QCA must consider the merits of additional public consultation (workshops and papers) on identified key issues.

*Draft Price Determination*

8. The QCA must investigate and publish its draft price determination on regulated retail electricity tariffs, with each tariff (to the extent practicable) to be presented as bundled prices appropriate to the retail tariff structure.

9. The QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the draft price determination.

10. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

***Final Price Determination***

11. The QCA must investigate and publish its final price determination on regulated retail electricity tariffs, with each tariff (to the extent practicable) to be presented as bundled prices appropriate to the retail tariff structure, and gazette the retail tariffs in the form of a Tariff Schedule.

***Time frame for QCA to make and publish reports (section 90AA(3)(b) of the Act)***

12. The QCA must make its reports available to the public and, at a minimum, publicly release the papers and price determinations listed in paragraphs 3 to 11.

13. The QCA must publish the interim consultation paper for the 2021–22 tariff year no later than one month after the date of this Delegation.

14. The QCA must publish the draft price determination on regulated retail electricity tariffs no later than March 2021.

15. The QCA must publish the final price determination on regulated retail electricity tariffs for the 2021–22 tariff year, and have the retail tariffs gazetted no later than 11 June 2021.

(SCHEDULE ENDS)

# APPENDIX B: STAKEHOLDER SUBMISSIONS AND REFERENCES

## Stakeholder submissions

We received 6 submissions in February 2021 on the interim consultation paper and 7 submissions in April/May 2021 on our draft determination. Non-confidential submissions are available on our website.

| ***Stakeholder*** | ***Submission number*** | ***Date received (2021)*** |
|---|---|---|
| AgForce | 10 | 23 April |
| Canegrowers | 6 | 11 February |
| | 11 | 30 April |
| Caravan Parks Association of Queensland (CPAQ) | 2 | 5 February |
| Cotton Australia | 5 | 9 February |
| | 9 | 23 April |
| Energy Queensland (EQ) | 3 | 9 February |
| | 8 | 23 April |
| Energy Queensland (confidential submission)* | 4 | 9 February |
| Etrog Consulting | 13 | 11 May |
| Queensland Electricity Users Network | 12 | 3 May |
| Queensland Farmers' Federation (QFF) | 1 | 5 February |
| | 7 | 23 April |

** EQ made a second confidential submission in May 2021, which it later withdrew.*

## References

ACIL Allen, *Updating retail costs for the 2021–22 regulated electricity price review – methodology document*, report for the QCA, December 2020.

—— *Estimated Energy Costs*, final report prepared for the QCA, May 2021.

—— *2021–22 regulated electricity price review – Updating retail costs*, final report prepared for the QCA, May 2021.

Australian Energy Market Commission (AEMC), *Advice on best practice retail price methodology*, final report, 27 September 2013.

—— *National Electricity Amendment (Global Settlement and Market Reconciliation) Rule 2018*, final rule determination, 6 December 2018.

—— *Bill contents and billing requirements*, final rule determination, 18 March 2021.

Australian Energy Market Operator (AEMO), *2019 Electricity Statement of Opportunities*, August 2019.

—— *2020–21 Electricity Final Budget and Fees*, June 2020.

—— *2020 Integrated System Plan*, July 2020.

—— *2020 Electricity Statement of Opportunities*, August 2020.

Australian Energy Regulator (AER), *Ergon Energy distribution determination*, *Attachment 18: tariff structure statement*, final decision, June 2020

—— *COVID-19 Retail Market Data Dashboard*, 29 March 2021, viewed 28 April 2021.

—— *Default Market Offer Prices 2021–22*, final determination, April 2021.

Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2020.

Ergon Energy, *Approved unmetered supply devices*, December 2017.

—— *Ergon Energy Tariff Structure Statement 2020–25*, June 2020 (erratum: version 6, August 2020).

Frontier Economics, *Retail Operating Costs*, report for the Economic Regulation Authority of Western Australia, March 2012.

Lewis, M and Liu, Q, 'The COVID-19 Outbreak Access To Small Business Finance', *Bulletin*, Reserve Bank of Australia, 17 September 2020.

Lowe, P, 'The Year Ahead', address to the National Press Club of Australia, Canberra, 3 February 2021.

Queensland Competition Authority (QCA), Regulated retail electricity prices for 2020–21, final determination, June 2020.

—— *Supplementary review: Regulated retail electricity prices for 2020–21*, final determination, October 2020.

—— *SEQ retail electricity market monitoring 2019–20 report*, November 2020.

Queensland Government, *Budget Strategy and Outlook 2020–21*, Budget Paper 2, December 2020.

—— *Gazette*, no. 72, 11 December 2020, pp. 519–522.

Reserve Bank of Australia (RBA), *Statement on Monetary Policy*, May 2021.

# APPENDIX C: ENERGY COST APPROACH

This appendix provides further detail on why we consider ACIL Allen's estimates are appropriate, including estimates for each of the three energy cost components (noted in section 4.2.1). It covers some of the more complex methods and assessments used in estimating energy costs.

ACIL Allen's final report, including the information we relied on to prepare this technical appendix, is available on our website.[1]

## Wholesale energy costs

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) to meet the demand of its customers. The NEM is a volatile market where spot prices are settled every half-hour[2] and currently can range from –$1,000 to $15,000 per megawatt hour (MWh)[3].

Retailers adopt a range of strategies to reduce spot price volatility risk (spot price risk), including:

- pursuing a hedging strategy by purchasing financial derivatives[4]—such as futures, swaps, caps and options
- entering long-term power purchase agreements (PPAs) with electricity generators
- investing in their own electricity generators (also known as vertical integration).

For this price determination, we engaged ACIL Allen to assist us with estimating wholesale energy costs for customers whose prices are settled on:

- the net system load profiles (NSLPs) in the Energex and Ergon areas
- the controlled load profiles (CLPs) for the load control tariffs available to both residential and small business customers in the Energex area. There are currently two types of CLPs of this nature—CLP 9000 and CLP 9100—which capture the consumption profiles of south east Queensland customers on tariffs equivalent to retail tariffs 31 and 33 respectively
- the CLPs for the small business load control tariff in the Energex area (Energex CLP, small business)
- the CLPs for large business load control tariffs in the Ergon area (Ergon CLP, large business).

The NSLPs and CLPs generally approximate how much electricity is consumed by customers on accumulation meters in a region, for every half-hour of the day. Unlike smart/interval meters, accumulation meters do not record when, or how much, electricity was consumed. To allow for settlement within the NEM (with different spot prices and volumes for settlement every half-hour), the Australian Energy Market Operator (AEMO) uses the NSLPs to approximate the amount of electricity consumed by customers on accumulation meters in a region. Currently, most customers in Queensland are on accumulation meters.

[1] ACIL Allen, *Estimated Energy Costs*, final report prepared for the QCA, May 2021.

[2] The Australian Energy Market Commission made a rule (in 2017) to change the financial settlement period for wholesale electricity spot prices from 30 minutes to 5 minutes, commencing on 1 October 2021.

[3] The minimum spot price (market floor price) and the maximum spot price (market price cap) are defined in chapter 3 of the National Electricity Rules. The market price cap is published by the AEMC every February and is effective from 1 July. For more information, see www.aemc.gov.au.

[4] Generally, purchasing financial derivatives enables retailers to lock in a price, or a maximum price (in the case of caps) at which a given volume of electricity will be transacted at a future date.

## Summary of analysis and findings

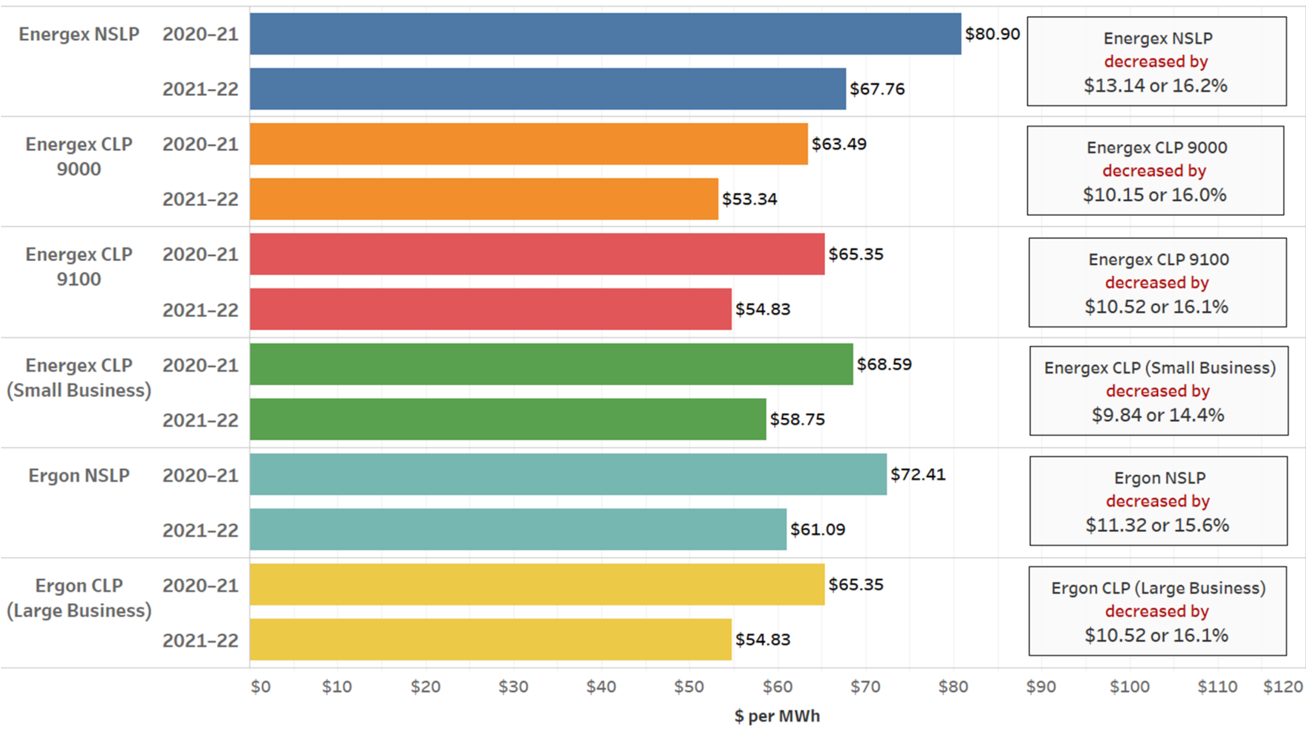
Consistent with previous years, ACIL Allen estimated wholesale energy costs using a market hedging approach designed to simulate the NEM from a retailer's perspective. A core feature of this approach is that it incorporates a hedging strategy that a prudent retailer would adopt to manage spot price risk in the market. More specifically, this involves:

- simulating the expected spot prices that a retailer faces, considering temperature-related demand profiles, generation supply/costs and power station availability; and then
- estimating wholesale energy costs for a retailer that hedges spot price risk through the purchase of ASX Energy futures.[5]

Compared to last year's estimates, ACIL Allen estimated a **decrease** in wholesale energy costs for 2021–22 for all customers whose prices are settled on the NSLPs and CLPs identified above (Figure 1). This reflects a decline in the trade-weighted ASX contract prices[6], primarily driven by the expected continued entry of large amounts of renewable generation into the NEM and prevailing lower domestic gas prices to date.

A range of factors contribute to lower domestic gas prices, including improved supply performance of coal seam gas (CSG) fields in Queensland, lower demand from gas-fired generation and a decline in international liquefied natural gas (LNG) export prices.

**Figure 1 Wholesale energy costs by demand profiles**




[5] ASX Energy futures are exchange-traded energy financial derivatives that allow retailers to reduce the spot price volatility risk when purchasing electricity from the NEM. For more information, see https://www.asxenergy.com.au/.

[6] Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for 2021–22.

## Demand considerations

To estimate wholesale energy costs, ACIL Allen used its stochastic demand model to develop 50 weather-influenced simulations of hourly demand for the NSLPs, CLPs and the system-wide demand for Queensland. The simulated hourly demand was developed using:

- temperature data from 1970–71 to 2019–20, historical demand profiles from 2017–18 to 2019–20 and the expected uptake of rooftop solar photovoltaic (PV)
- AEMO's latest demand forecast for 2021–22, including energy forecasts of AEMO's neutral scenario and the seasonal peak demands with a 10% probability of exceedance (POE)[7], 50% POE and 90% POE.[8]

The weather-influenced system-wide hourly demand (i.e. the demand satisfied by scheduled and semi-schedule generation[9]) was then used to simulate the expected spot prices, while the simulated NSLPs and CLPs were required to develop separate wholesale energy estimates for each profile.

The historical demand profiles were sourced from AEMO. However, for the newly introduced tariffs without historical profiles (i.e. the load control tariffs for small and large business customers), ACIL Allen used the relevant representative demand profiles recently developed for the purpose of the October 2020 price determination.[10]

The demand profile for the small business load control tariff was derived using EQ's tariff trial load data for 2019–20, while the profile for large business load control tariffs was based on the Energex CLP 9100. More details (on how these demand profiles were developed) are available in Appendix C and ACIL Allen's final report for the October 2020 price determination.

### Demand profiles and historical energy cost levels

This section provides an overview of the demand profiles that ACIL Allen used for its analysis. Over the past number of years, the shape of the Queensland system-wide load profile has become 'peakier', with an increasing difference between the levels of peak and average demand (Figure 2). This is primarily due to a substantial uptake of rooftop solar PV, which has decreased daytime demand but has had limited effect on the evening peak demand.

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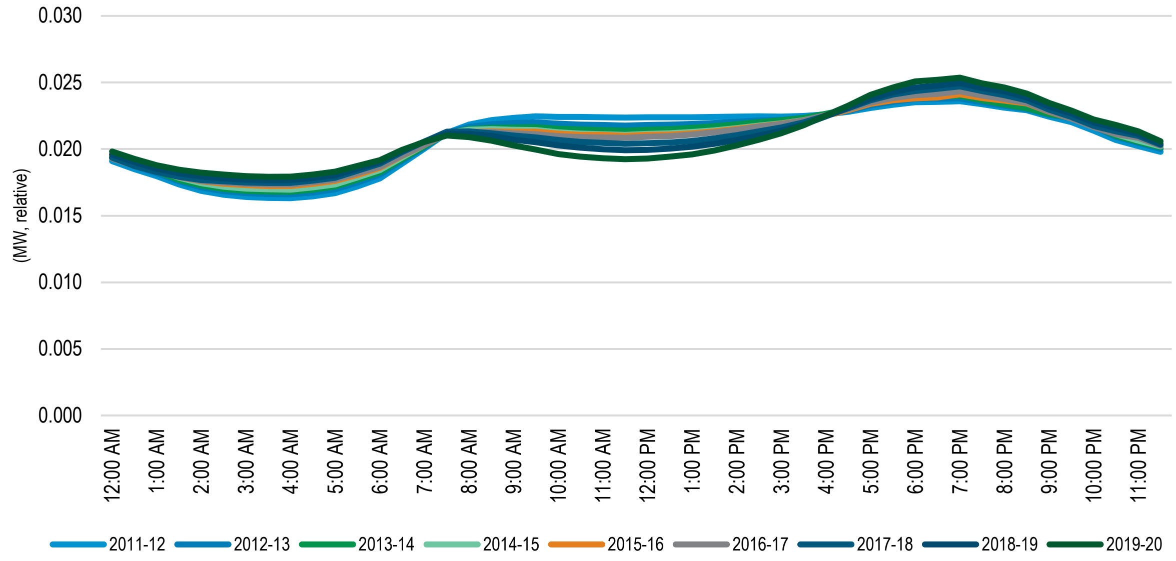
[7] POE is the probability of whether an electricity demand forecast will be met or exceeded. For example, a demand level with a 10% POE implies that there is a 10% probability of the forecast being met or exceeded. The 10% POE forecast is mathematically expected to be met or exceeded once in 10 years and represents demand under more extreme weather conditions (than, for example, a 50% POE forecast).

[8] AEMO, *2020 Electricity Statement of Opportunities*, August 2020.

[9] Generators with controllable output and a capacity over 30 MW are usually classified as scheduled generation. This type of generation is largely made up of coal and gas-fired generation as well as hydro power plants. In contrast, generators with intermittent output (such as wind and solar farms) and a capacity over 30 MW are generally classified as semi-scheduled generation. If required, for system security, AEMO can control the output of scheduled generation but can only constrain the output of semi-scheduled generation.

[10] QCA, *Supplementary review: Regulated retail electricity prices for 2020–21*, final determination, October 2020.

**Figure 2 Queensland system-wide load profile**

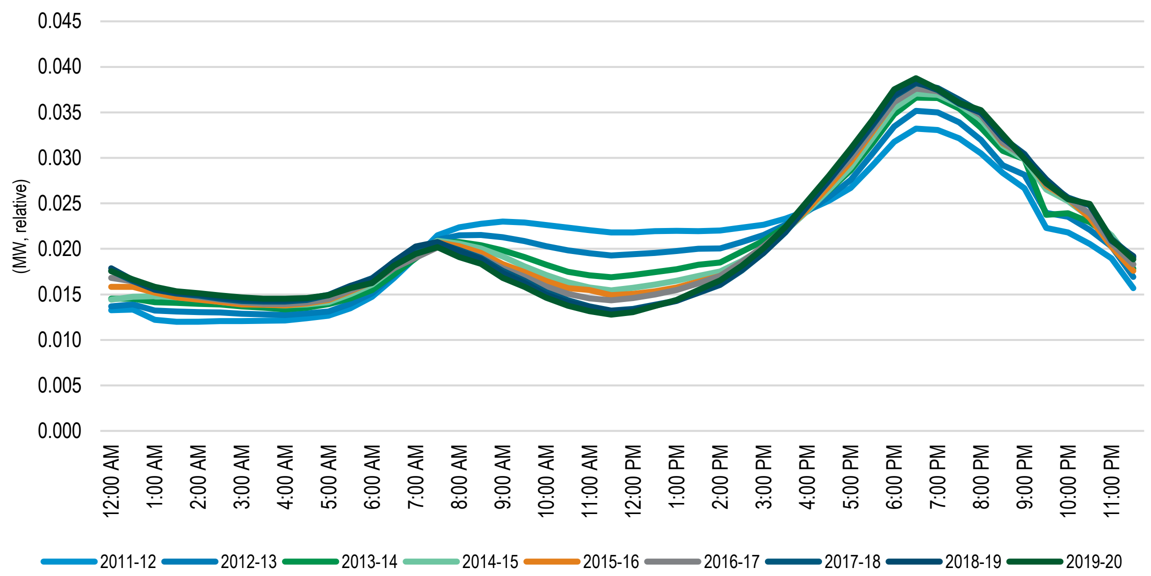



*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation of the load, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, final report prepared for the QCA, May 2021.*

Similarly, the Energex and Ergon NSLPs have also become 'peakier' over time, due to the increased penetration of rooftop solar PV (Figures 3 and 4). On the Energex NSLP, more electricity from the grid is consumed during peak periods than on other demand profiles. Consequently, the Energex NSLP has the highest wholesale energy costs of the profiles analysed in Queensland. The Ergon NSLP is less 'peaky' than the Energex NSLP and consequently has lower wholesale energy costs.

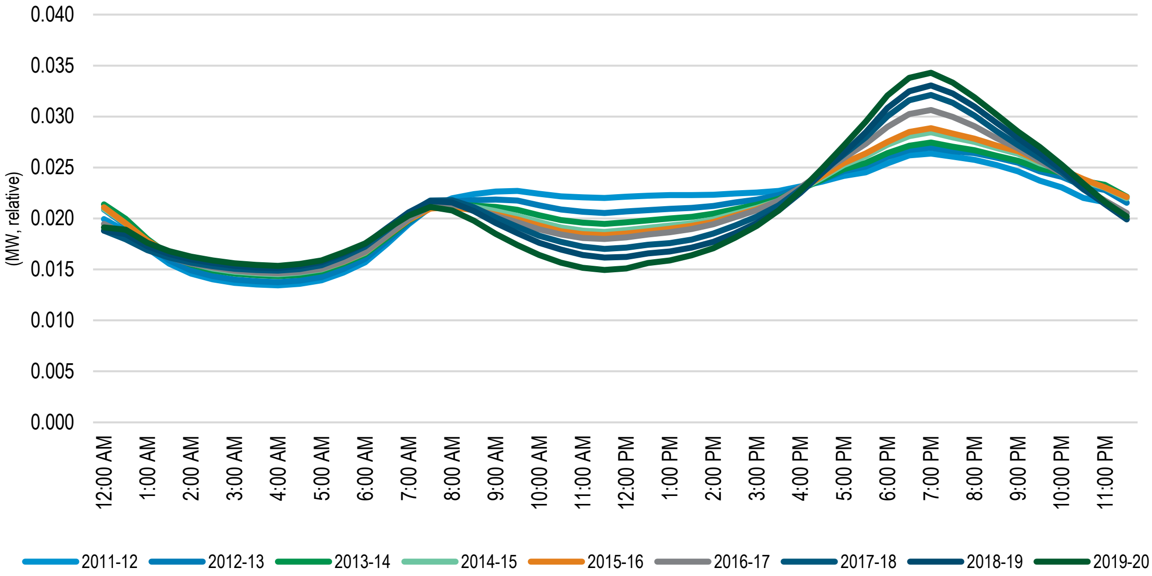
**Figure 3 Energex NSLP**




*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, final report prepared for the QCA, May 2021.*

**Figure 4 Ergon NSLP**

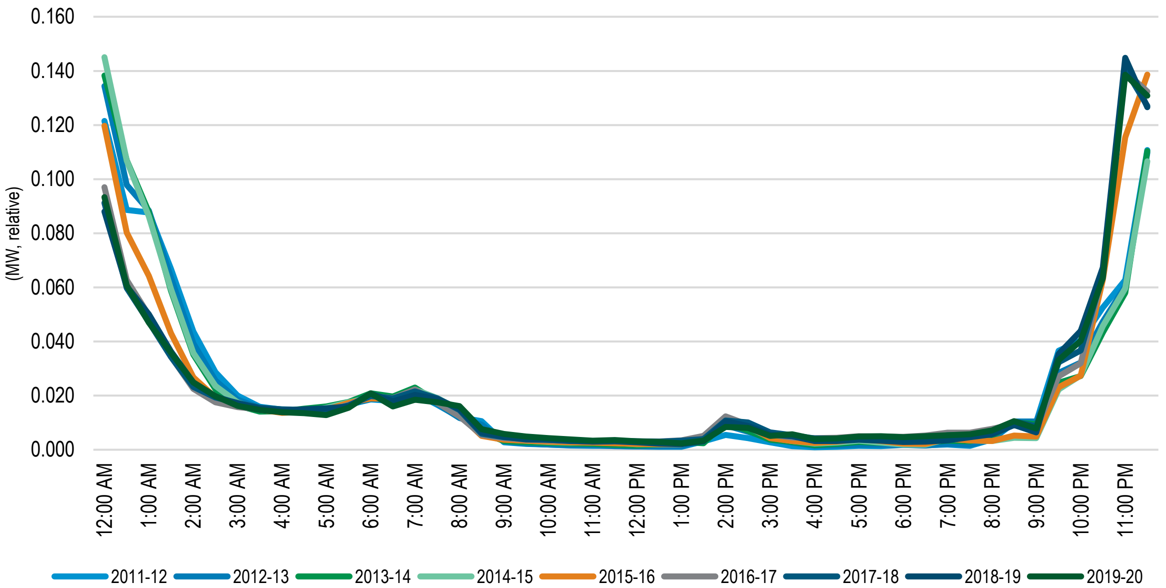



*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, final report prepared for the QCA, May 2021.*

On the Energex CLPs, more electricity is generally consumed during off-peak periods and non-summer quarters (due to higher water heating loads in non-summer months) than on the Energex and Ergon NSLPs (Figures 5 and 6). Therefore, the Energex CLPs have lower wholesale energy costs relative to the NSLPs. The Energex CLP for retail tariff 33 typically has a higher wholesale energy cost than the Energex CLP for retail tariff 31. This is because the former generally has more electricity consumed during peak periods compared to the latter.

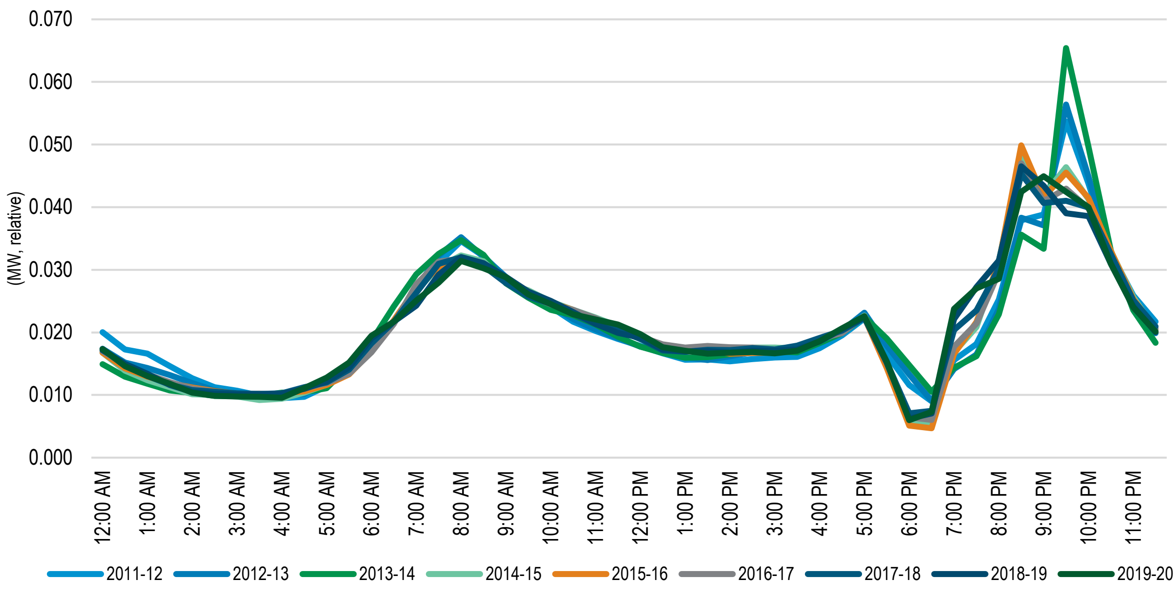
**Figure 5 Energex CLP 9000 (retail tariff 31)**




*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, final report prepared for the QCA, May 2021.*

**Figure 6 Energex CLP 9100 (retail tariff 33)**

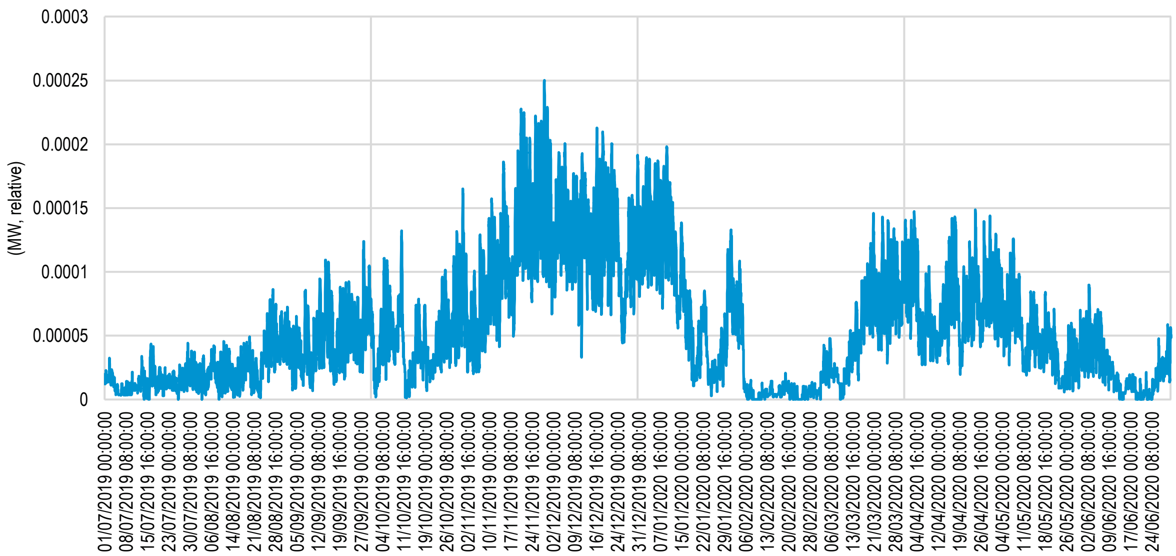



*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, final report prepared for the QCA, May 2021.*

The demand profile for the small business load control tariff exhibits an extended period of low load, with loads tending to peak during summer—that is, between November and early January (Figure 7). This profile typically has a higher wholesale energy cost than the Energex CLP for retail tariff 33. This is due to the former having relatively more electricity consumed during the peak summer months than the latter.

**Figure 7 Energex CLP (small business)—tariff trial data, 2019–20**




*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen's analysis of data from Energy Queensland's agricultural tariff trial.*

## Supply considerations

In addition to developing the 50 simulated demand profiles, ACIL Allen used its stochastic outage model to develop 11 hourly power station availability simulations. ACIL Allen also estimated a set of renewable energy resource traces[11] that are consistent with the weather conditions for the demand profiles from 2017–18 to 2019–20. Such an approach maintains the appropriate correlation between various demand profiles and renewable energy resource traces, as both electricity demand and renewable generation vary based on weather patterns.

ACIL Allen then applied its proprietary electricity model (PowerMark) to generate 550 simulations of 8,760 hourly wholesale electricity spot prices for 2021–22, using the stochastic demand profiles, renewable energy resource traces and power station availabilities as inputs.

PowerMark simulates the behaviour of generators in the NEM, considering the cost and technological characteristics of generators, fuel prices, generator bidding strategies, demand for electricity, weather and power station availability. ACIL Allen incorporated changes to the existing generation supply, where market participants have formally announced changes, including mothballing, closure and change in operating approach of power plants. Near-term new generators are included, should ACIL Allen deem these plants to be committed projects.

ACIL Allen's forecast of the generation supply and costs within the NEM closely aligns with AEMO's Integrated System Plan (ISP).[12] To achieve this, ACIL Allen routinely compared its detailed assumptions with the ISP's findings, including the technical parameters of generators, fuel prices and interconnector expansions. Any deviation in assumptions was investigated, and the ISP's findings were adopted if the deviation could not be justified. However, it should be noted that, to date, ACIL Allen's assumptions were closely aligned with the ISP's findings.

ACIL Allen advised that its wholesale spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX futures) for 2021–22. More details are available in chapters 2 and 4 of ACIL Allen's final report.

## Hedged energy costs—hedging methodology and contract prices

To simulate the wholesale energy costs incurred by a retailer that hedges spot price risk, ACIL Allen developed a hedging methodology based on the standard ASX Energy base, peak and cap futures contracts. To develop a hedging methodology, ACIL Allen tested a substantial number of strategies to derive the strategy with the lowest cost and variance, considering the weather-influenced simulated demand profiles.

Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for 2021–22. To calculate the trade-weighted futures contract prices, ACIL Allen used the contract prices and volume of contracts traded until and including 1 May 2021. In the case of peak contracts, these data were supplemented with information from TFS Australia (an energy brokerage company).

As a result of the five-minute settlement reform, ACIL Allen has used prices and trade volume from the newly listed ASX cap contract[13] to estimate the trade-weighted prices for cap contracts. In 2017, the Australian Energy Market Commission (AEMC) made a rule to change the financial settlement period for

[11] Renewable energy resource traces reflect the availability and quality of renewable resources/generation in different renewable energy regions across the NEM, depending on weather and geographical conditions.
[12] AEMO, *2020 Integrated System Plan*, July 2020.
[13] The new cap contract is known as the Australian Base Load 5 Minute Cap Futures Contract.

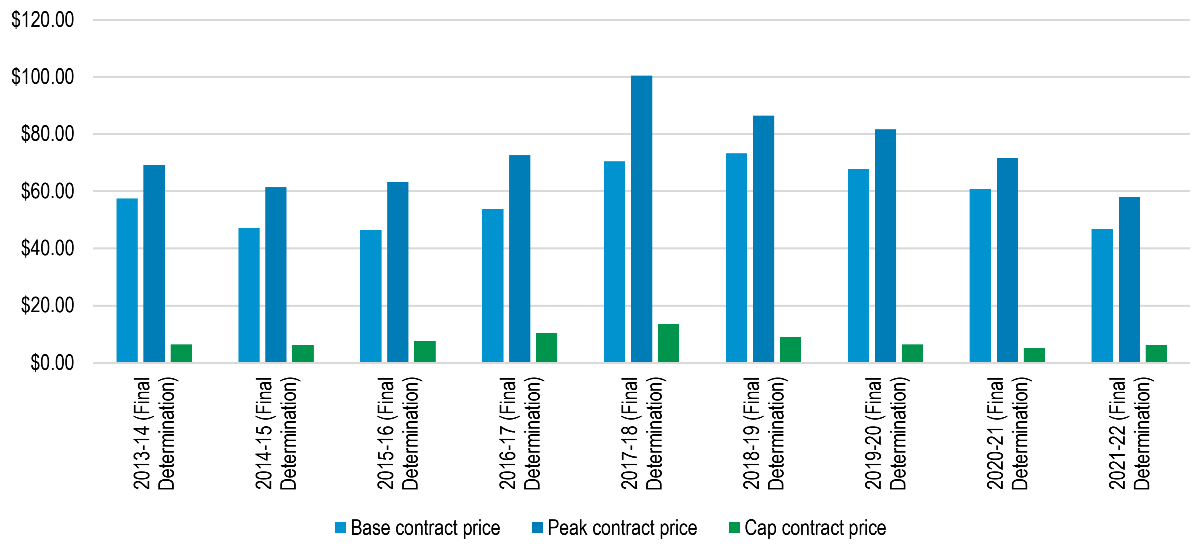
wholesale electricity spot prices from 30 minutes to 5 minutes, commencing on 1 October 2021.[14] One key change due to this reform is that ASX Energy introduced new cap contracts (designed for a five-minute settlement) to replace the existing cap contracts (intended for a 30-minute settlement).

More details on ACIL Allen's approach are available in chapter 4 of its final report.

As shown in Figure 8, compared to last year's contract prices, estimates of futures contract prices for 2021–22, on an annualised and trade-weighted basis, have to date:

- decreased by about $14/MWh for base contracts
- decreased by about $13.50/MWh for peak contracts
- increased by about $1.20/MWh for cap contracts.

**Figure 8 Annualised quarterly electricity futures contract prices ($/MWh)**




*Source: ACIL Allen, Estimated Energy Costs, final report prepared for the QCA, May 2021.*

This reflects market participants expecting further softening in spot prices due to the expected continued entry of a large amount of renewable generation. Approximately 4,000 MW of new utility-scale renewable generation is expected to enter the NEM over the next 12 to 18 months.

Another driver of lower contract prices for 2021–22 is the prevailing lower domestic gas prices (to date) for gas-fired generation of electricity. Gas spot prices across the Australian east coast market have remained low over the past 12 months. The reasons for the lower domestic gas price include improved supply performance of CSG fields in Queensland, decreased demand from gas-fired generation and a decline in international LNG export prices.

Surplus global LNG supply is expected to keep international LNG prices lower over the next 12 to 18 months (excluding the peak demand periods associated with the northern hemisphere winter). It is likely that the reduction in international LNG export prices has diminished the attractiveness of selling gas on the LNG spot market, thereby improving domestic gas supply and putting downward pressure on domestic gas prices.

[14] The AEMC indicated this reform would provide better price signals for investment in fast-response technologies in the NEM, such as batteries, demand response and new generation gas peaking plants.

ACIL Allen applied the hedging methodology (together with the simulated spot prices) to derive 550 annual hedged energy costs for a given demand profile, with the 95th percentile of the distribution of hedged costs used as the final estimate of the wholesale energy costs.

### Our consideration—wholesale energy costs

Our final position is to estimate the wholesale energy costs based on the advice from ACIL Allen (discussed in section 4.2.1).

We consider ACIL Allen's use of a market-based approach is appropriate for the task of estimating wholesale energy costs. While other methods exist, notably a long-run marginal cost (LRMC) approach, we are satisfied that a market-based approach is the most appropriate. This is because, unlike a market-based approach:

- a LRMC approach generally does not reflect the prevailing market conditions within the NEM and relevant financial markets. Prevailing market conditions, such as current electricity demand, supply–demand balance and market participants' expectations are likely to have a significant influence on wholesale energy costs
- cost information necessary to accurately undertake an LRMC approach is generally contained within confidential PPAs. Even if this information could be acquired, the LRMC approach would contribute to a lower level of transparency in our analysis.

Importantly, the market-based approach has the advantage of being more transparent than other methodologies, because it uses financial derivative data (i.e. ASX contract data) that are readily available in the public domain.

For the newly introduced tariffs without historical profiles (i.e. the load control tariffs for small and large business customers), we consider it appropriate to use the relevant representative demand profiles recently developed as part of the October 2020 determination. As these new tariffs are yet to be taken up widely by customers, there is insufficient data to refine the demand profiles developed previously.

In developing its forecasts of demand profiles and generation supply/costs, ACIL Allen used the latest available market data, including information on the uptake of rooftop solar PV, renewable energy resource traces, AEMO's latest peak demand and supply projections as well as market participants' formal announcements on generation availability/operation. We consider that such an approach adequately takes into account the likely variation in demand profiles and generation supply/costs within the NEM.

We also note ACIL Allen's approach has generated a distribution of spot prices for 2021–22 that is consistent with the distribution and variability of historical outcomes. This distribution covers a wide range of potential price outcomes that captures the extent and level of high spot price events consistent with those observed historically.

Furthermore, ACIL Allen's spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX futures) for 2021–22. Generally, the purchase of ASX futures enables retailers to lock in a price, or a maximum price (in the case of caps), at which a given volume of electricity will be transacted at a future date. Therefore, futures contract prices incorporate market participants' risk-weighted expectations of future spot prices.

To develop a hedging methodology, ACIL Allen tested a substantial number of strategies to derive a strategy with the lowest cost and variance, considering the latest simulated demand profiles. We consider such an approach to be appropriate, as it is likely to reflect how a retailer, in practice, would optimise its hedging strategy when using ASX futures. We note that the hedging strategy developed for 2021–22 is the same as the one adopted for last year's price determination.

To estimate wholesale energy costs, ACIL Allen took the 95th percentile of the distribution of 550 annual hedged energy costs for a given demand profile. We consider this is a conservative estimate, given there is only a 5 per cent probability that the final estimate underestimates the energy costs that retailers face in the NEM.

### Spot price simulation—negative spot prices

EQ noted that the time-weighted average spot price (TWP) for Queensland to date (for 2020–21) is around $38/MWh, while the simulated minimum TWP for the 2020–21 determination was about $48/MWh. On this basis, EQ said we should consider modifying the spot price forecasting methodology, including adjusting the frequency of negative spot prices in the simulation to reflect the more frequent occurrence of negative prices to date.[15]

We do not consider the modifications EQ suggested are appropriate. Such modifications would require ex post adjustments to the spot price simulation, which we are not in favour of, as:

- the methodology reflects the best information available at the time when the projected spot prices were developed
- the factors leading to lower-than-expected spot prices and higher frequency of negative spot prices are likely specific to 2020–21.

As noted by EQ, Queensland spot prices to date (for 2020–21) are lower than the simulated spot prices for the 2020–21 determination. The actual spot prices to date are also lower than what market participants in the ASX futures markets expected them to be at the time when the 2020–21 determination was made. This is likely due to, among other things:

- the upgrade works on the Queensland to New South Wales interconnector (QNI) between August and October 2020. This has resulted in the derating of the QNI, which reduced the electricity flows from Queensland to New South Wales during daylight hours. Such a development contributed to lower spot prices during daylight hours and a higher propensity of negative spot prices, when excess rooftop PV generation is exported to the grid. ACIL Allen had incorporated the expected effects of the QNI upgrade works into its spot price modelling but not to the same extent as the actual effects. However, the propensity of negative spot prices has declined since November 2020, coinciding with the completion of the upgrade works and the return of the QNI to normal levels of capacity
- the mild summer for 2020–21 due to La Niña weather pattern. Peak operational demand in Queensland (to date) has been below AEMO's 90% POE demand forecast[16] adopted for the spot price simulation used in last year's price determination. This has resulted in actual spot prices being lower than the simulated spot prices during evening peak periods. However, AEMO noted that its latest demand forecasts aimed to capture relevant weather trends, including seasonal variability, El Niño/La Niña, and climate change.[17] These demand forecasts were used for the spot price simulation for this determination.

ACIL Allen also undertook a sensitivity analysis using the actual spot prices to date (rather than the simulated spot prices) to re-estimate the Energex NSLP wholesale energy costs for 2020–21. This sensitivity test was undertaken using the same hedging methodology adopted in last year's price determination. The

[15] EQ, sub. 3, pp. 12–13.
[16] AEMO, *2019 Electricity Statement of Opportunities*, August 2019.
[17] AEMO, *2020 Electricity Statement of Opportunities*, August 2020.

resulting 95th percentile wholesale energy estimate from this analysis is $80.63/MWh, only 0.3 per cent lower than the equivalent estimate of $80.90/MWh in last year's price determination.[18]

We consider that this analysis demonstrates the robustness and stability of ACIL Allen's methodology in estimating wholesale energy costs.

### Five-minute settlement reform and the availability of cap contracts

EQ said we should investigate the effects of the AEMC's five-minute settlement reform and its impact on the availability of ASX cap contracts and hedging strategy:

> The commencement of the five-minute settlement (5MS) rule in October 2021 means caps are not currently being traded on the Australian Stock Exchange (ASX). As electricity retailers will have already put in place electricity contracts for financial year 2021-22, the assumed use of cap contracts and their price may need to be amended in the ACIL Allen hedging model to reflect the current unavailability of cap products.[19]

We investigated whether retailers are relying on other types of financial derivatives to compensate for the lack of ASX cap contracts, but market observations suggest this is not the case. To date, the volume of ASX base contracts traded for 2021–22 has converged to the volume traded for the previous year. This suggests, at this stage, that retailers are not relying on base contracts as a replacement for the cap contracts.

Further, ACIL Allen has consulted TFS Australia (an energy brokerage company) on other potential financial products that can be used to compensate for the lack of ASX cap contracts. The only other noteworthy product (other than base contracts) is the super peak contract[20]. However, TFS indicated that, to date, there has been negligible trade in this product.

Due to the five-minute settlement reform, ASX Energy introduced new cap contracts[21] (designed for a five-minute settlement) to replace the existing cap contracts (intended for a 30-minute settlement). We investigated the viability of using the prices and trade volume of the newly listed cap contracts to estimate wholesale energy costs.

We concluded that such an approach is appropriate on the basis that there is a reasonable level of trading in the newly listed cap contracts. The level of trades for these new contracts (since they have been available) is comparable to the level of trades for the existing cap contracts for the same duration (in the July to September 2021 quarter). In the absence of more reliable information, we consider the trade-weighted prices of the new cap contracts to be the best indicator (of the current market view) of the costs that retailers are likely to incur when hedging with cap contracts.

The approach of using data from the new cap contracts is also consistent with EQ's view that actual traded price of cap contracts would be a better guide in estimating the costs that retailers will incur.[22] We also note that the AER adopted the same approach when determining the wholesale energy costs for the 2021–22 DMO.

[18] ACIL Allen advised that this outcome can be attributed to the interaction between the simulated spot prices and the hedging strategy adopted. In a volatile spot price market, an optimal hedging strategy generally results in over-hedging during non-peak periods (i.e. the load level being less than level of hedging) and under-hedging during peak periods (i.e. load level being greater than level of hedging). Actual spot prices being lower than the simulated spot prices (during daytime non-peak periods) can lead to a higher wholesale energy costs due to over-hedging. However, this is largely offset by actual spot prices being lower than the simulated spot prices (during evening peak periods), which can lead to lower wholesale energy costs due to under-hedging.

[19] EQ, sub. 3, pp. 12–13.

[20] A super peak contract is designed to cover demand in the early morning and evening peak periods (i.e. outside of the main periods in which rooftop solar PV produces electricity).

[21] The new cap contract is known as the Australian Base Load 5 Minute Cap Futures Contract.

[22] EQ, sub. 8, pp. 9–10.

### Hedging strategy

EQ said we should examine the hedging strategy adopted to estimate wholesale energy costs:

> [T]he AER's DMO methodology consultation paper has proposed significant changes to the ACIL Allen methodology compared to the methodology they have been using for the QCA price determination. In particular, Energy Queensland notes that the DMO methodology selects a hedging portfolio that delivers the lowest net hedged cost and that this portfolio is selected after the spot price simulations have been completed. This is akin to an electricity retailer selecting a hedging strategy after a trading period has been completed and spot price outcomes are known. This could result in unusual hedging portfolios that would not be representative of hedging portfolios actually adopted by electricity retailers. For example, the hedging portfolio set out in the DMO methodology consultation paper had an unusually high weighting of caps (80%) which would be high risk for an electricity retailer that did not know in advance what the spot price outcome would be. Given that the ASX is not trading caps for 2021-22, a high weighting of caps is not appropriate for estimating energy costs for 2021-22 retail prices.[23]

We can confirm that, when developing the hedging strategy to estimate wholesale energy costs, ACIL Allen used the same approach as in previous years. To develop a hedging methodology, ACIL Allen tested a substantial number of strategies to derive the mix of ASX base, peak and cap contracts with the lowest cost and variance, considering the weather-influenced simulated demand profiles.

Once an appropriate hedging strategy was developed, the same strategy (i.e. the same hourly hedge volumes, in MW) was applied to all 50 simulated demand profiles and therefore to all 550 spot price simulations. This means that ACIL Allen does not alter the hedge volumes on an ex post basis for each of the 50 demand profiles.

### Separate wholesale energy cost estimates for irrigation

Canegrowers suggested that a separate wholesale energy cost be estimated for irrigation activities to reflect the relevant network tariff structures and 'include a substantial discount to encourage off-peak use and a premium in the late afternoon/early evening (4pm to 9pm) in recognition of the evening peak'.[24]

We consider that wholesale energy cost estimates should reflect how retailers incur costs when purchasing electricity from the NEM. At this stage, most small business customers in Queensland (such as irrigators) are on accumulation meters.

Accumulation meters do not record the time of day electricity was consumed or how much was consumed at that time. To allow for settlement within the NEM (with different spot prices and volumes for settlement every half-hour), AEMO uses the NSLPs to approximate the amount of electricity consumed by customers on accumulation meters in a region. In other words, the average wholesale spot prices that retailers pay for customers on accumulation meters are determined by using the NSLPs.

Consequently, the cost to a retailer purchasing electricity to supply an irrigator with an accumulation meter is based on the NSLPs. On this basis, we consider it appropriate to continue with the existing approach of estimating wholesale energy costs for irrigation activities based on the NSLPs.

### Covid-19

EQ noted that covid-19 has had, and will continue to have, an impact on the demand of customers.[25] We consider that ACIL Allen's methodology has adequately taken into account the potential impacts of covid-19 on the NEM through:

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[23] EQ, sub. 3, pp. 12–13.
[24] Canegrowers, sub. 6, p. 2.
[25] EQ, sub. 3, pp. 12–13.

- the use of AEMO's latest demand forecasts from its 2020 Electricity Statement of Opportunities (ESSO) report, in which AEMO incorporated the projected impacts of covid-19
- the incorporation of ASX contract data until 1 May 2021. These contract prices reflect, to date, the market participants' views of the impacts of covid-19, as well as other drivers, on the NEM
- the use of a large number of simulations (i.e. 550 simulations) to estimate wholesale energy costs, which covers a wide range of demand outcomes. These demand outcomes are likely to adequately capture the volume risks[26] that retailers face.

### Price cap and comparing wholesale spot prices with hedged energy costs

QEUN stated that wholesale electricity prices should be capped at $60/MWh, but we do not consider an arbitrary cap is appropriate for the task at hand. It would introduce the risks of understating the costs of supply as energy costs fluctuate due to market conditions in the NEM and relevant financial markets. This would also mean setting notified prices that are inconsistent with the Queensland Government's UTP, which requires prices for small customers to be based on the cost of supply in SEQ (where wholesale electricity prices are not capped).

QEUN also compared wholesale prices with our hedged energy cost estimates. However, wholesale prices do not reflect the costs that retailers incur in practice when sourcing electricity from the NEM. To manage spot price volatility risk, retailers generally lock in the price for an amount of electricity that they will pay for in the future (e.g. through the purchase of ASX contracts). In other words, retailers had already locked in higher future electricity prices for a proportion of electricity to be supplied in 2021–22, before the more recent decline in wholesale and contract prices. This means that, in addition to wholesale prices, a retailer's hedging strategy plays a crucial role in determining the actual costs the retailer incur when purchasing electricity from the NEM.

### Conclusion

We consider ACIL Allen's market hedging approach:

- adequately addresses the issues raised in stakeholder submissions
- is likely to produce reliable estimates that best reflect the costs retailers incur (when purchasing electricity from the NEM) by using the latest available market data and publicly available ASX contract data.

## Other energy costs

In addition to estimating wholesale energy costs, we need to account for other energy costs that retailers incur when purchasing electricity from the NEM:

- renewable energy target (RET) costs
- NEM management fees and ancillary services charges
- prudential capital costs
- Reliability and Emergency Reserve Trader (RERT) costs
- costs associated with the Retailer Reliability Obligation (RRO).

Our position is to estimate other energy costs based on ACIL Allen's advice (discussed in section 4.2.1).

[26] Volume risks in this context refer to the financial risks associated with the exposure to fluctuation in the demand of electricity that needs to be sourced from the NEM.

## Renewable energy target

The RET scheme provides incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions. It consists of the large-scale renewable energy target (LRET) and small-scale renewable energy scheme (SRES). The costs of these incentives are paid by retailers through the purchase of large-scale generation certificates (LGCs) and small-scale technology certificates (STCs).

LGCs or STCs can be created when eligible electricity is generated by utility-scale renewable generators or small-scale renewable systems. Retailers surrender the purchased LGCs and STCs to the Clean Energy Regulator (CER) to meet their obligations under the RET scheme.

### Large-scale renewable energy target

The LRET sets annual targets for the amount of electricity that must be sourced from large-scale renewable energy projects, such as utility-scale wind and solar generation. The mandated LRET is 33,000 GWh for both 2021 and 2022.[27]

Retailers must purchase a set number of LGCs according to the:

- renewable power percentage (RPP) published by the CER
- amount of electricity they have acquired and sold to customers in the calendar year.

To estimate the LRET costs, ACIL Allen used a market-based approach by forecasting the expected average LGC prices and RPP values. Under this approach, LRET costs (in $/MWh) for the relevant calendar years were estimated by multiplying the expected average LGC prices and RPP values. The LRET cost for the financial year was derived by averaging the two calendar-year estimates.

ACIL Allen estimated that the LRET cost for 2021–22 will be $4.29/MWh for all retail tariffs—a reduction of $0.70/MWh compared to the 2020–21 determination. This reduction is mainly due to lower expected LGC prices.

ACIL Allen's market-based approach to estimating LRET costs uses the latest data, where available and appropriate. We consider this approach is likely to produce a reliable and transparent estimate of LRET costs to be incurred by retailers in 2021–22. It is also preferable to a cost-based approach that uses the LRMC of renewable energy generation. This is because, unlike the market-based approach:

- the LRMC of renewable generation generally does not reflect the prevailing market conditions for LGCs. Prevailing market conditions such as the market participants' expectations and supply–demand balance for LGCs are likely to have a significant influence on LGC prices and therefore LRET costs
- cost information necessary to accurately undertake an LRMC approach is generally contained within confidential PPAs. Even if this information could be acquired, this approach would contribute to a lower level of transparency in our analysis.

#### Large-scale generation certificate prices

The expected LGC prices were estimated using LGC forward prices[28] provided by TFS Australia (an energy brokerage company). ACIL Allen has improved the way it estimates the expected LGC prices by using the trade-weighted average (rather than the simple average) of LGC forward prices for 2021 and 2022. This approach assumes that retailers build up their LGC coverage over a period of time to meet their obligations under the LRET scheme.

[27] *Renewable Energy (Electricity) Act 2000* (Cth), s. 40. More information can be found on the Clean Energy Regulator's website.

[28] Forward prices are predetermined prices for an underlying commodity, currency, or financial asset, as agreed between the buyer and seller of a forward contract, to be transacted at a future date.

ACIL Allen estimated the expected LGC prices to be $25.71/MWh for 2021 and $20.61/MWh for 2022. LGC forward prices have fallen since they were last estimated for the 2020–21 determination. This reflects the market's expectation of a continued increase in supply of LGCs because of an increase in committed renewable investment, driven by decreasing costs in renewable generation, demand for renewable PPAs from corporate users and an earlier appetite of renewable investors to take on greater exposure to merchant risks[29].

The lower average LGC forward prices also reflect the market view that the LRET scheme is likely to be fully subscribed soon.

The LGC forward market is an active market consisting of several brokers and trading platforms. As such, we consider that it provides a sound basis for estimating the value of LGCs. LGC forward pricing is likely to be a reliable indicator of the current market view of LGC costs that retailers will face to meet their obligations under the LRET scheme.

ACIL Allen estimated these forward prices using a trade-weighted average of LGCs traded, rather than a simple average. We consider that this approach is appropriate, as it provides a more accurate representation of the LGC costs that retailers are likely to incur. Further, it is aligned with our approach to estimating wholesale energy costs, where futures contract prices are estimated on a trade-weighted basis.

#### Renewable power percentage

As discussed, the RPP values dictate the number of LGCs that a retailer needs to purchase and surrender to the CER. The CER has determined the RPP for 2021 at 18.54 per cent in March 2021.

To estimate the RPP for 2022, ACIL Allen used the mandated LRET targets (published by the CER) and its estimates of electricity acquisitions for 2022. The RPP value was estimated by dividing the LRET target by the electricity acquisitions of liable entities. ACIL Allen's approach to calculating the RPP aligns with the CER's. The estimated RPP for 2022 is 18.54 per cent. We consider ACIL Allen's approach to estimating the RPP to be appropriate, as it is aligned with the CER's expectations and therefore likely to reflect the LRET obligations that retailers will face in practice.

### Small-scale renewable energy scheme

The SRES provides an incentive for individuals and small businesses to install eligible small-scale renewable energy systems—such as solar panel systems, small-scale wind systems, small-scale hydro systems, solar hot water systems and heat pumps. Customers installing these systems create STCs, which retailers must purchase and surrender to the CER to fulfil their obligations under the SRES.

As with the LRET, retailers must purchase a set number of STCs according to the:

- small-scale technology percentage (STP) published by the CER
- amount of electricity they have acquired and sold to customers in the calendar year.

ACIL Allen estimated the SRES costs by multiplying the expected STC price and the relevant calendar-year STP. The SRES cost for the financial year was derived by averaging the two calendar-year estimates.

The SRES cost for 2021–22 is estimated to be $11.52/MWh for all retail tariffs—an increase of $2.21/MWh compared to the 2020–21 determination. This substantial increase is mainly driven by higher STPs, which reflect a higher uptake in small-scale renewable energy systems than previously estimated.

We consider that ACIL Allen's methodology to estimating SRES costs is appropriate, as it aligns with the way retailers are likely to incur these costs in practice, taking into account CER's requirements and STC clearing

[29] Merchant risks in this context refer to the financial risks associated with the exposure to movement of spot prices in the NEM. Generally, this type of risk can be managed through power purchase agreements.

house processes. Such an approach is likely to produce a reliable estimate of the SRES costs to be incurred by retailers in 2021–22.

#### Small-scale technology certificates price

The expected STC price was based on the CER's clearing house price. The STC clearing house is operated by the CER, and the clearing house price is currently fixed at $40 per STC (or per MWh of electricity generated by eligible renewable systems).

We consider that ACIL Allen's approach of estimating the expected STC price is appropriate. Although there is an active market for STCs, these market prices are unlikely to be the best indicator of future STC prices. This is because the STC market is designed to clear every year, with the CER adjusting the STPs annually with a target STC price of $40 per certificate (i.e. the CER's clearing house price).

#### Small-scale technology percentage

As discussed, the STP values dictate the number of STCs that retailer needs to purchase and surrender to the CER. To estimate the STPs for the final determination, ACIL Allen has used the CER's binding STP of 28.8 per cent for 2021 and its own estimate of 28.8 per cent for 2022. The 2021 binding STP is much higher than the CER's earlier published non-binding estimate of 19.4, reflecting a higher uptake in small-scale renewable energy systems than previously estimated.

For this final determination, ACIL Allen has opted to use its own forecast of the 2022 STP, rather than the CER's non-binding estimate. We consider this to be appropriate, as ACIL Allen's more recent forecast will capture the latest developments in the uptake of small-scale renewable energy systems. This is also consistent with the AER's approach to estimating the SRES costs in its 2021–22 DMO final determination.

Given the CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination, we have historically provided a pass-through to reflect the actual SRES costs that retailers incur (discussed in section 5.3).

## NEM management fees and ancillary services charges

When purchasing electricity from the NEM, retailers incur fees to cover the costs of operating the NEM and managing power system safety, security and reliability.

### NEM management fees

NEM management fees are levied by AEMO to cover its costs related to operating the NEM, full retail contestability and the funding of Energy Consumers Australia. ACIL Allen estimated the NEM fees using the budget and projected fees in AEMO's report on its budget and fees for 2020–21.[30]

ACIL Allen estimated that for 2021–22, NEM fees will be $0.49/MWh, a decrease of $0.22/MWh, compared to the 2020–21 determination. This decrease reflects a decline in costs related to operating the NEM and the exclusion of costs associated with AEMO's function as the National Transmission Planner (NTP).

In previous determinations, the costs related to the NTP was included in the NEM management fees. However, the recovery of these costs has been transferred recently to the transmission network service providers, forming part of the transmission use of system charges.

We consider ACIL Allen's approach to estimating the NEM fees is appropriate, as it reflects how retailers are likely to incur these costs in practice, taking into account AEMO's latest budget and projected fees. Such an approach is likely to produce a reliable estimate of the NEM management fees to be incurred by retailers in 2021–22.

[30] AEMO, *2020–21 Electricity Budget and Fees*, June 2020.

### Ancillary services charges

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability. These services maintain key technical characteristics of the electricity grid, including standards for frequency, voltage, network loading, and system restart processes. Ancillary services are divided into three major categories—Frequency Control Ancillary Services (FCAS), Network Support Control Ancillary Services (NSCAS) and System Restart Ancillary Services (SRAS).

ACIL Allen estimated the ancillary services charges using the region-specific average ancillary service payments[31] observed over the preceding 52 weeks. For 2021–22, ancillary services charges were estimated to be $0.41/MWh, a decrease of $1.12/MWh, compared to the 2020–21 determination. This decrease is mainly due to:

- the commissioning of additional generation supply, which offers ancillary services to this relatively small market
- no major power system separation events occurring, such as the events in 2019 and 2020.[32]

We consider ACIL Allen's methodology is appropriate, given the highly uncertain nature of ancillary service costs, which are heavily dependent on the state of the power system and the amount of service required at any particular time to maintain power system security and reliability. In practice, the need for ancillary services (and therefore costs) can vary significantly from period to period.

## Prudential capital costs

Prudential capital costs are the costs that a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX in order to trade in futures contracts. ACIL Allen estimated prudential capital costs in line with the latest published AEMO requirements and margin requirements for trading in the ASX futures market.

Prudential costs for customers, whose prices are settled on the Energex NSLP, were estimated using the consumption profile of the Energex NSLP. These costs were also used as a proxy for the prudential costs of the Energex CLPs. Conversely, prudential costs of the Ergon NSLP were estimated using the consumption profile of the Ergon NSLP.

Prudential costs have fallen since last year's price determination, largely driven by lower contract prices and lower expected price volatility in the NEM. ACIL Allen estimated the 2020–21 prudential costs to be $1.67/MWh for the Energex NSLP (and CLPs) and $1.36/MWh for the Ergon NSLP.

We consider that ACIL Allen's approach to estimating prudential costs is appropriate, as it is aligned with how retailers are likely to incur these costs in practice, taking into account AEMO's prudential requirements and the ASX's margin requirements. This approach is likely to produce reliable estimates of prudential costs to be incurred by retailers in 2021–22.

### AEMO prudential costs

When sourcing electricity from the NEM, a retailer is required to provide financial guarantees to AEMO. These financial guarantees (prudential obligations) are essential for AEMO to manage credit risks associated with a retailer's financial ability to meet its contractual obligations when purchasing electricity from the NEM.

[31] AEMO provides data on weekly settlements for ancillary service payments in each interconnected region within the NEM.

[32] For the 2020–21 determination, ancillary services fees were higher mainly due to the Basslink interconnector outage in Tasmania, the planned outage of the Heywood to Mortlake line in Victoria and the extended power system separation between South Australia and Victoria.

When estimating the AEMO prudential costs, ACIL Allen assumed that the retailer has no vertical integration (through generation ownership or PPAs) and does not engage in reallocation of prudential obligations. Reallocation is an AEMO procedure that allows counterparties to reduce their prudential obligations through instruments such as swaps or options.

To determine the required prudential obligations, AEMO assesses and calculates a maximum credit limit (MCL) for each counterparty (or retailer in this context). ACIL Allen used the MCL, the relevant consumption profiles and the costs of funding a bank guarantee to estimate the AEMO prudential costs that a retailer is expected to incur.

ACIL Allen estimated the 2021–22 AEMO prudential costs to be $0.42/MWh for the Energex NSLP (and CLPs) and $0.33/MWh for the Ergon NSLP. More details on ACIL Allen's approach are available in chapter 4 of its final report.

We consider ACIL Allen's approach to estimating the AEMO prudential costs to be appropriate as it reflects how retailers are likely to incur these costs in practice, considering AEMO's prudential requirements. This approach generally reflects the simplest way that a retailer could fulfil its prudential obligations to AEMO.

If a retailer chooses to adopt a more complex approach to meet its prudential obligations (such as engaging in a relocation of obligations using swaps or options), it is likely that the retailer perceives the additional benefits in doing so. On this basis, we consider that ACIL Allen's approach should result in a conservative estimate for the costs of meeting AEMO's prudential obligations.

### Hedge prudential costs

Retailers are required to lodge initial margins with the ASX to trade in ASX futures contracts. These margins are essential for the ASX to manage risks associated with a retailer's financial ability to meet its contractual obligations when trading in futures. The costs of these margins (hedge prudential costs) must be accounted for, as ASX futures were relied upon to hedge spot price risks and derive the wholesale energy costs estimates. When ACIL Allen estimated the hedged prudential costs, it considered:

- the costs of funding the margins—noting that the funds lodged as margins with the ASX receive a money market return, which offsets some of the funding costs
- the ASX parameters that determine the initial margin—including the price scanning range, intra-monthly spread charge and spot isolation rate for base, peak and cap contracts
- the annual average prices for base, peak and cap contracts
- the consumption profiles of the Energex and Ergon NSLP.

An additional margin may apply when contract prices move in an unfavourable manner for the buyer or seller of ASX contracts. However, ACIL Allen did not provide an allowance for an additional margin, as it is assumed that favourable and unfavourable movements in contract prices will cancel each other out over time.

ACIL Allen estimated the 2021–22 hedge prudential costs to be $1.25/MWh for the Energex NSLP (and CLPs) and $1.03/MWh for the Ergon NSLP. More details on ACIL Allen's approach are available in chapter 4 of its final report.

We consider ACIL Allen's approach to estimating the hedge prudential costs to be appropriate, as it is aligned with the way retailers are likely to incur these costs in practice, considering the ASX's margin requirements. Such an approach is likely to produce reliable estimates of prudential costs to be incurred by retailers in 2021–22.

### Reliability and Emergency Reserve Trader

Retailers incur a fee levied by AEMO to cover the costs of the Reliability and Emergency Reserve Trader (RERT) mechanism. The RERT allows AEMO to contract for emergency reserves, such as generation or demand response outside of the NEM. This is meant to provide AEMO with the flexibility it needs when managing power system reliability while minimising the costs to consumers.

ACIL Allen considered it challenging to project these costs with a sufficient degree of accuracy. It noted that while it may be possible to project the RERT costs using its previous costs and AEMO's projection of unserved energy (USE)[33], there is currently not sufficient data to do so.

Therefore, as with the ancillary services, ACIL Allen proposed to forecast the RERT costs using the costs published by AEMO for the 12-month period prior to 2021–22. At the time of our final determination, no RERT costs were incurred in Queensland for 2020–21.

We consider ACIL Allen's methodology is appropriate, given the highly uncertain nature of the RERT costs—the RERT is only called upon by AEMO under extreme circumstances. AEMO uses the RERT as a safety net if a critical shortfall in reserves is forecasted. The RERT scheme is only activated once all market options have been exhausted, generally during periods when the supply–demand balance is tight.

### Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) is designed to assist with managing the risk of declining reliability of generation supply, in response to the recent influx of intermittent renewable generation coupled with the recent/potential closures of thermal power plants. It was implemented on 1 July 2019.

When the RRO is triggered for a given quarter and NEM region, retailers are required to secure sufficient qualifying contracts to cover their share of the one-in-two-year peak demand. At this stage, for 2021–22, the RRO has not been trigged for Queensland, and therefore no RRO costs have been incurred.

However, we consider that this cost component should be incorporated as part of the wholesale energy costs, as retailers are required to modify their contract cover (such as using ASX contracts) to ensure sufficient coverage if the RRO is triggered. We will consider the appropriate methodology to account for the RRO costs when the RRO is triggered for Queensland.

[33] USE is the electricity that cannot be supplied to consumers, resulting in involuntary loss of customer supply (load shedding). USE generally occurs due to insufficient levels of generation capacity, demand response or network capability to meet demand.

## Summary of other energy costs

The other energy costs that retailers are expected to incur are summarised in the charts below.

**Figure 9 Other energy costs—LRET and SRES**

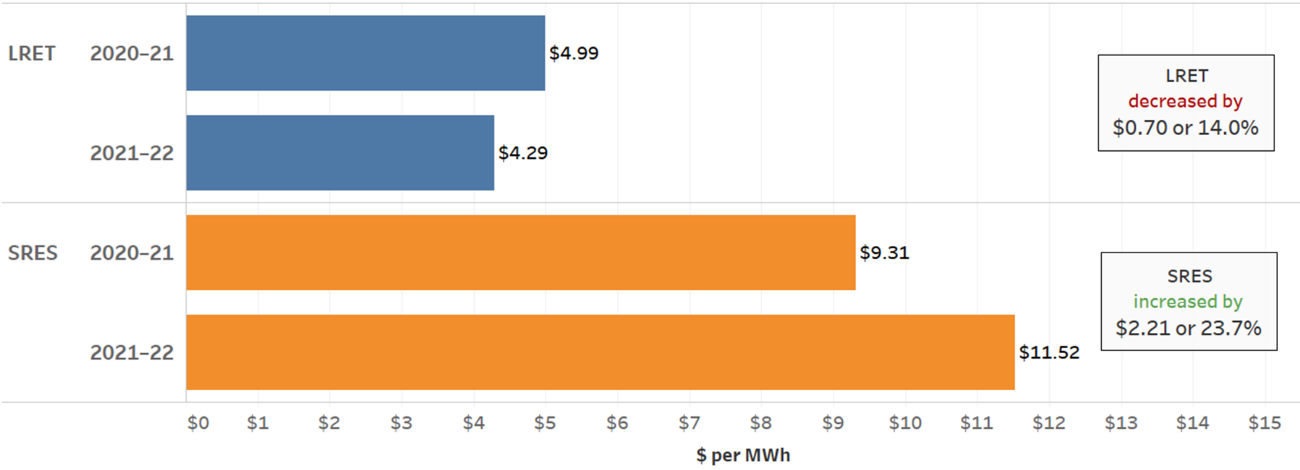



**Figure 10 Other energy costs—NEM fees, ancillary services and prudential costs**

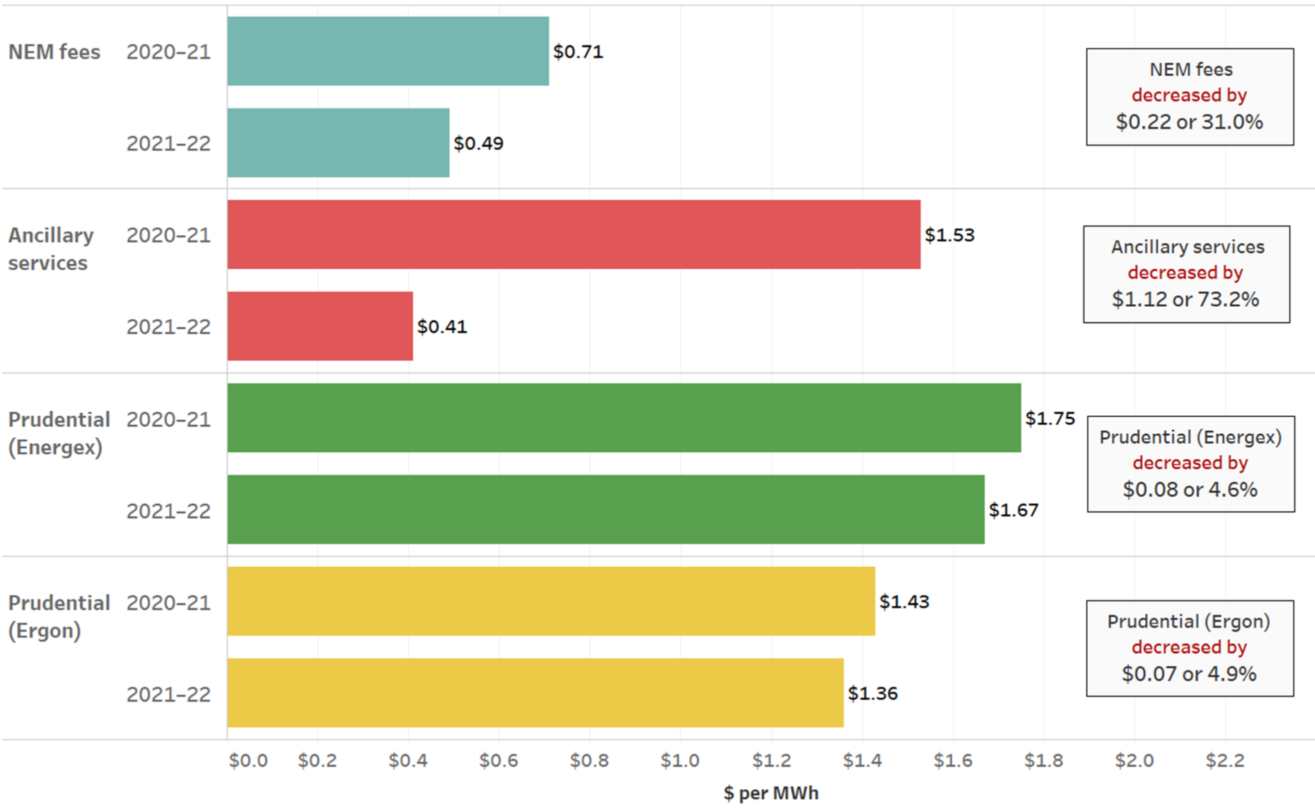
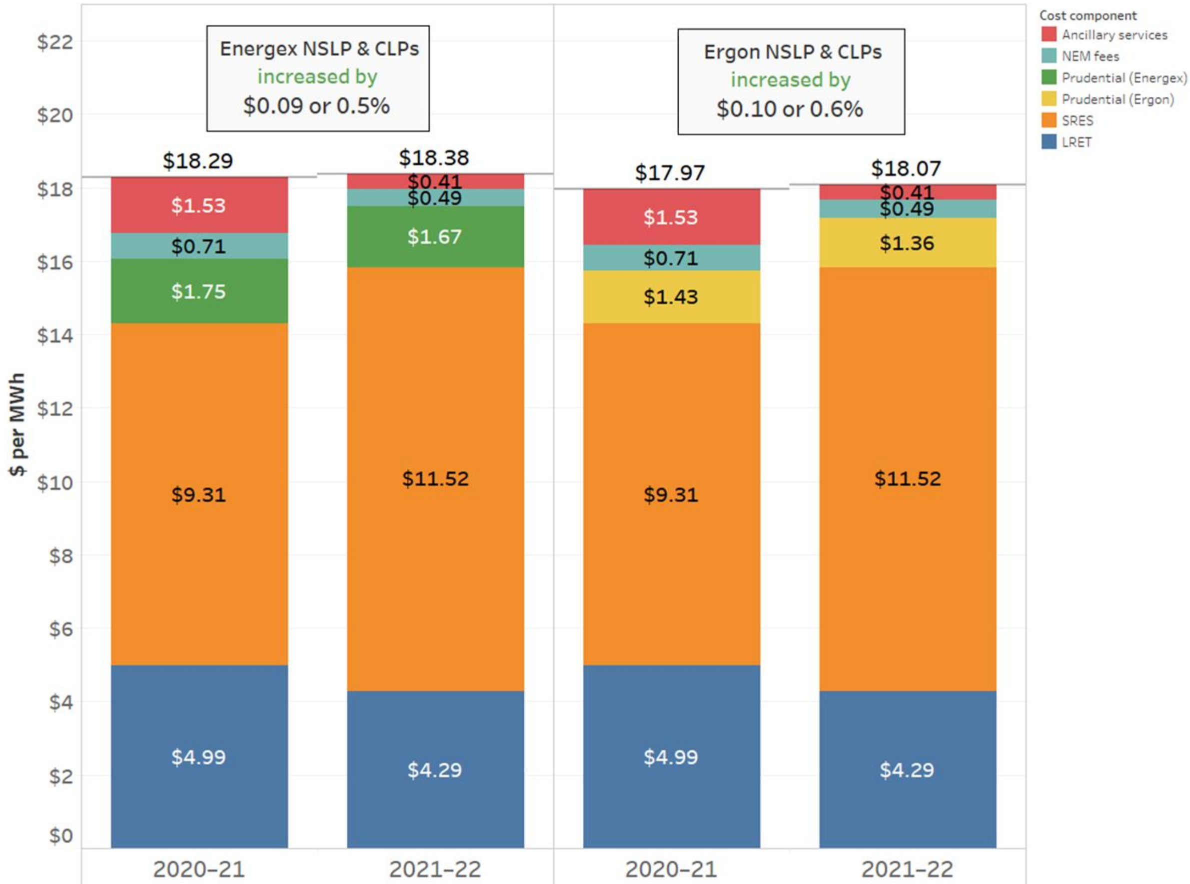


**Figure 11 Total other energy costs**




## Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

ACIL Allen accounted for energy losses by applying the latest transmission and distribution loss factors published by AEMO in a manner that aligns with AEMO's NEM settlement process. These loss factors are:

- the average energy-weighted transmission loss factor—estimated by ACIL Allen, using the loss factors and energy consumed at each of the transmission node identities provided by AEMO
- the distribution loss factor published by AEMO.

The calculated losses in ACIL Allen's final report have been updated to reflect AEMO's 2021–22 published loss factors.

Compared to estimates for last year, overall energy loss factors[34] have:

- increased for small customer tariffs, reflecting an increase in distribution loss factors
- increased for large customer tariffs, reflecting an increase in transmission loss factors.

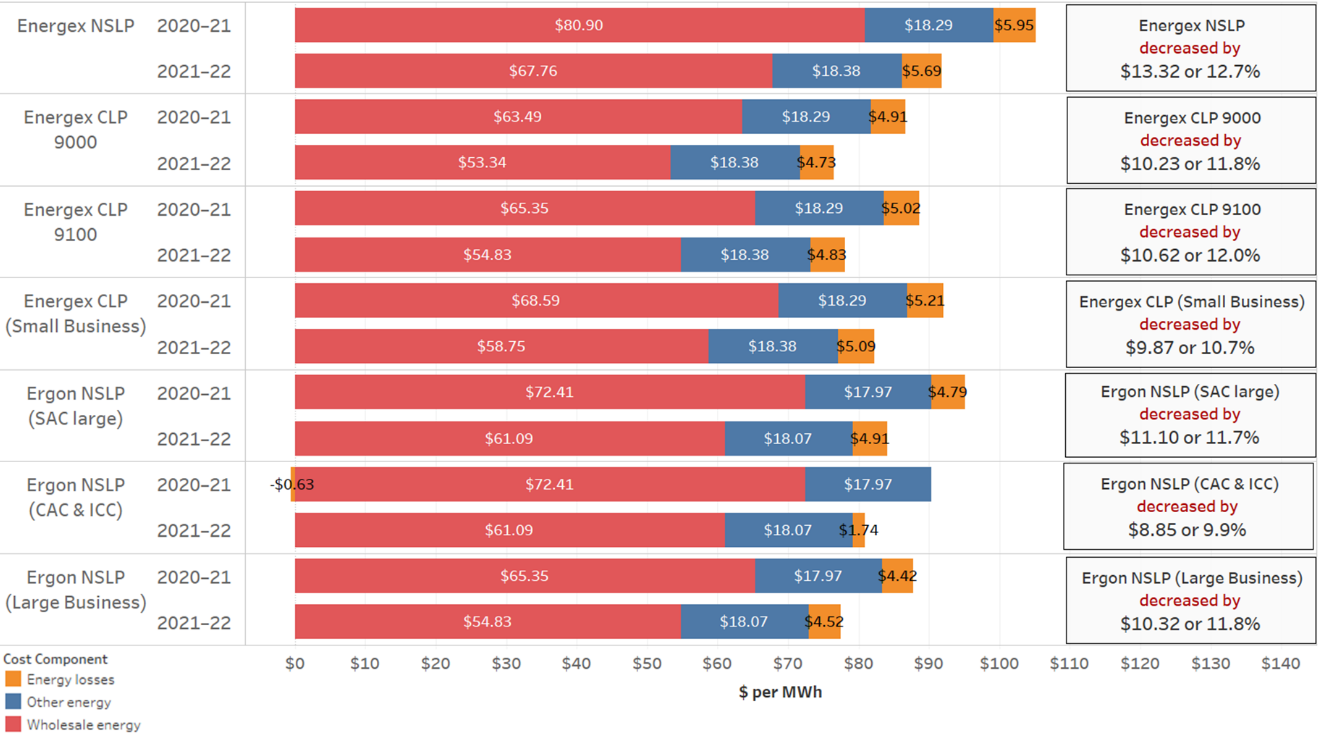
Our position is to estimate the energy losses based on ACIL Allen's advice. We consider ACIL Allen's methodology is likely to best reflect the actual energy losses incurred by retailers, given its alignment with AEMO's settlement process.

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

## Total energy cost allowances for 2021–22

The changes in total energy cost allowances for 2021–22 is summarised in the chart below.

**Figure 12 Changes in total energy cost allowances**




*Note: Totals may not add up precisely due to rounding.*

# APPENDIX D: RETAIL COSTS APPROACH

This appendix provides further detail on why we consider it is appropriate to use:

- ACIL Allen's approach for updating the existing retail cost benchmark allowances for residential and small business customers
- the existing retail cost allowances for large and very large customers.

Further detail on ACIL Allen's approach is explained in its methodology paper, draft report and final report, available on our website.

## Background

Retail costs are the costs of running a retail business (as explained in Chapter 4, section 4.2.2). They include:

- retail operating costs, such as administrative costs and costs related to operating call centres, operating billing systems and collecting revenue
- a retail margin, which is the return to investors for retailers' exposure to systematic risks associated with providing retail electricity services.

The delegation requires us to consider determining the R component by undertaking a review of retail operating costs. We have undertaken a more fulsome review of all retail costs, which includes the retail operating costs and retail margin.

We last undertook a comprehensive review of retail costs as part of the 2016–17 price determination. In determinations since then, we have set the retail cost allowance using an established benchmark (set as part of the 2016–17 price determination process), adjusted for inflation.

## Summary of analysis and findings

Having regard to stakeholder comments, ACIL Allen's reports and our own analysis, we have:

- updated the retail cost allowances for residential and small business customers (small customers) to take account of recent market information
- used the existing retail cost allowance for large and very large customers, adjusted by inflation.

To calculate the retail component of the 2021–22 notified prices for small customers, we have used ACIL Allen's retail cost estimates from its benchmarking analysis. Specifically, we have applied the fixed retail costs and used the variable retail costs to derive the variable retail cost allocators. The allocators allow us to apply the variable retail costs consistently across different types of tariffs.[35]

[35] The allocators represent variable retail costs as a percentage of non-retail variable costs (such as energy and network costs).

**Table 1 Retail costs—fixed costs and variable cost allocator for small customers**

| | ***Fixed cost* *($ per year)*** | ***Variable cost allocator* *(%)*** |
|---|---|---|
| Residential customers | 123.35 | 7.25 |
| Small business customers | 172.68 | 18.7 |

*Source: QCA analysis, using data from ACIL Allen.*

To calculate the retail component of the 2021–22 notified prices for large and very large customers, we maintained our approach—that is, to adjust the 2020–21 fixed retail cost allowances for inflation and maintain the variable retail cost allocators at 6.04 per cent (the same level established in the 2016–17 determination). While we considered establishing new retail cost allowances for these customers, we have not done so at this time because of issues identified with data quality.

## Approach to estimating retail costs for 2021–22

ACIL Allen used a combination of benchmarking and bottom-up approaches to estimate retail costs, informed by analysis of retail market offers, detailed confidential information provided by retailers and publicly available data.

### Small customers

#### Benchmarking approach

The benchmarking approach used by ACIL Allen to update the retail cost allowances for small customers is broadly consistent with the approach used for the 2016–17 review. However, changes have been made to potentially improve the benchmarking analysis this year, by:

- using all retail market offers, rather than the lowest priced market offers
- using market offers in SEQ only, rather than including offers in other jurisdictions
- considering time-of-use, demand and load control tariffs, in addition to flat-rate tariffs
- considering whether further adjustments should be made to account for recent market developments.

ACIL Allen established a dataset of relevant retail offers, using market offers in SEQ as published on the Australian Energy Regulator's (AER's) Energy Made Easy (EME) website. The market offers were used to arrive at the annual electricity bills based on an average consumption (and demand), before deducting network costs and energy costs. The residual amount reflects the total retail cost component, split into fixed and variable retail components.

To arrive at the residual retail cost component, ACIL Allen:

- primarily used market offers from the first quarter of 2020–21[36]—we provided ACIL Allen with EME offers for the first and second quarters of 2020–21. We note that energy costs used for the benchmarking analysis were estimated as part of our 2020–21 price determination (around May 2020). The timing of when these estimates were developed is closest to the retail offers introduced in the first quarter of 2020–21. Retailers are more likely to update their energy cost estimates to account for more recent developments as they introduce new offers after the first quarter. For these reasons, the benchmarking analysis was primarily based on first quarter offers and the second quarter offers were used for comparison and verification

[36] For clarity, this refers to Q1 of the 2020–21 financial year.

- calculated annual bills using 2019–20 average consumption and demand levels—we provided ACIL Allen with the average consumption and demand for the relevant tariff types in Energex's distribution area, where 2019–20 data is the most recent available data
- factored in discounts and fees in the bill calculation—ACIL Allen factored in all quantifiable conditional and unconditional discounts that are available to customers. Upfront discounts were amortised over a period applying the rate of customer switching. Fees were treated as negative discounts
- removed outliers from the analysis—ACIL Allen removed tariffs with electricity bills that were more than two standard deviations from the mean
- deducted relevant network costs from the annual bills[37]— ACIL Allen used the network tariffs that apply in 2020–21 in Energex's distribution area. ACIL Allen noted that while it was relatively straightforward to assign the appropriate network tariffs to the flat-rate retail tariffs, it was more complicated for time-of-use and demand retail tariffs
- deducted energy costs from the annual bills[38]—ACIL Allen used the energy costs estimated as part of our 2020–21 price determination
- used a weighted average approach—to better reflect market conditions, ACIL Allen estimated the retail cost allowances based on benchmarked costs weighted by the market share of each retailer (i.e. the number of customers served by each retailer) rather than a simple average (as in the 2016–17 determination).

### Adjusting for recent market developments

ACIL Allen considered whether any adjustments should be made to the benchmarking analysis to account for any recent market developments, such as productivity improvements, covid-19 and regulatory reform. Given that retail costs are estimated using 2020–21 market offers, an adjustment will be necessary only where developments in 2021–22 would result in a material change in costs relative to those incurred in 2020–21.

In considering whether any adjustment is required as a result of productivity improvements, ACIL Allen considered the real movement in retail operating costs over the period from 2014–15 to 2019–20 as published by AGL and Origin Energy, and over the period from 2007–08 to 2017–18 as reported by the ACCC.[39]

In relation to the costs associated with the impact of covid-19, ACIL Allen examined the AER's and Essential Services Commission's (ESC's) considerations of the impact of covid-19 as part of the Default Market Offer (DMO) and Victorian Default Offer (VDO) regulatory decisions, respectively. ACIL Allen also considered the movements of various performance indicators published by the AER[40], and the Reserve Bank of Australia's (RBA's) Statement on Monetary Policy, which is published four times a year.

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[37] Network costs include network charges, jurisdictional scheme amounts and metering charges.

[38] Energy costs include wholesale energy costs, costs of complying with the Renewable Energy Target, National Electricity Market related fees, ancillary services charges and costs of meeting prudential requirements and energy losses.

[39] The ACCC's 2017–18 Inquiry into Retail Electricity Pricing analysed the components of retail electricity prices for residential consumers, including retail costs and margins, using data obtained from the retailers.

[40] The AER publishes various performance indicators that can be analysed to illustrate the impact of covid-19 on retailers' operations. For example, the indicators outline the number of customers on hardship programs, number of customers repaying debt, average debt of hardship and non-hardship customers, number of complaints and number of disconnections.

### Large customers

We considered establishing new retail cost allowances for large and very large customers as part of this review. Given the absence of publicly available data for these customers, information requests[41] were issued to retailers to obtain the retail costs that they forecast to be incurred in 2020–21.

Cost information was requested for the following cost categories: customer service and contract management, billing and payment, acquisition and retention, IT systems, energy procurement costs, regulatory compliance costs, regulatory fees, support and overheads, depreciation, amortisation, interest, tax, return on assets and other costs. Cost data was requested on a per customer basis, per megawatt hour basis and per megawatt basis. Retailers were also requested to provide the number of customers they supplied and the average consumption profiles (usage and demand) for these customers.

We received confidential data from five retailers. Of these retailers, all five provided data relating to large customers, and four provided data relating to very large customers. Retail costs for two of the five retailers were significantly different; therefore, they were excluded from the analysis.[42]

The retailers' data were used to calculate weighted averages of retail costs for these customers. Two separate estimates were derived using weightings based on the number of customers for each retailer and the energy consumed by those large customers. Results were similar irrespective of the weightings used.

## Our consideration—retail costs for small customers

Our position is to estimate the retail costs for small customers based on the advice from ACIL Allen (discussed in section 4.2.2).

ACIL Allen's benchmarking approach is broadly consistent with the approach used in 2016–17, with updates to account for more recent market data. We consider this is a robust and transparent approach, as it relies heavily on outcomes observed in competitive retail markets.

Our approach means that the retail margin cannot be isolated from any other component of the overall total retail costs. However, we do not consider it necessary to estimate a retail margin, or any other discrete retail cost component. Rather, our approach focuses on estimating a total level of retail costs, which implicitly includes some retail margin, portions of which are recovered through fixed and variable charges.

### Use of market data

Under the UTP, we must consider setting notified prices for small customers in regional Queensland based on the costs to supply small customers in SEQ. Given this, the retail cost estimates for 2021–22 are based on all retail market offers in SEQ. We note this market is likely to be effectively competitive for several reasons, including:

- the large number of offers available—158 market offers were available for residential and small business customers for the first quarter of 2020–21
- the large number of retailers operating in SEQ—these 158 offers were supplied by 30 retailers.[43]

Our 2019–20 market monitoring report noted that the SEQ retail market is generally consistent with a competitive market. This can be attributed to an increasing number of offers (which gives customers more

[41] This data is commercially sensitive and cannot be reproduced in this report.

[42] We note that the retail costs for both of these retailers lie just outside the definition of an outlier (more than two standard deviations from the mean).

[43] ACIL Allen, *2021-22 regulated electricity price review – Updating retail costs*, final report prepared for the QCA, May 2021, Appendix A.

choice), an increasing number of retailers, a declining market share of incumbent retailers and an increasing price dispersion.[44]

We note that SEQ has the highest level of satisfaction with competition in Australia. The Energy Consumer Sentiment Survey published in December 2020 reported that SEQ has the highest level of satisfaction with competition in Australia, at 69 per cent (an increase of 13 per cent from the previous survey).[45]

As a result of improved publicly available data, we estimated the retail cost allowances based on benchmarked costs weighted by the market share of each retailer[46], rather than using a simple average (as in the 2016–17 determination). In the 2016–17 benchmarking analysis, ACIL Allen needed to make assumptions regarding retailer market share in the absence of public data to derive weighted average retail cost estimates. For this review, we used the customer data reported by the AER for the first quarter of 2020–21 to calculate weighted average retail cost estimates.[47]

We consider that a weighted average approach is likely to be more reflective of the costs that retailers in SEQ incur. It also lessens the impact of any loss-leading offers put forward by retailers competing to increase their market share. The effects of loss-leading offers are also likely to be addressed through the removal of outliers from the analysis. This should avoid any substantial artificial lowering of retail costs[48] and should also exclude offers with excess retail margins.[49] Overall, the weighted average approach, combined with the removal of outliers, should provide an appropriate representation of retail costs.

### Flat-rate tariffs as the basis for retail costs of all tariffs

Consistent with our approach in 2016–17, the estimates for flat-rate tariffs have been used as the basis for calculating retail costs for all tariffs.

We considered developing separate retail cost estimates for other tariff types (such as time-of-use, demand and load control tariffs), but this proved to be challenging. This is because the introduction of more complex network tariffs (as part of the ongoing network tariff reform[50]) has resulted in retailers adopting a variety of strategies for passing through these new network tariff charges and structures. This makes it difficult to assign appropriate network tariffs when undertaking the benchmarking analysis for these tariffs.

As part of the network tariff reform, EQ introduced more complex new network tariffs, and has retired or grandfathered[51] existing network tariffs. For the time-of-use tariffs, new network tariffs with different charging windows were introduced and the existing network tariffs were grandfathered. For the demand tariffs, EQ introduced two new network tariffs[52] that are identical in structure but have different usage and demand charges. Additionally, the existing demand network tariff for residential customers was retired, while the tariff for small business customers was grandfathered.

Our analysis indicated that retailers are passing through the network charges and structures in an inconsistent manner. For the time-of-use tariffs, we observed that most retailers were adopting the

[44] QCA, *SEQ retail electricity market monitoring 2019–20 report*, November 2020, chapter 9.
[45] Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2020, p. 18.
[46] Market share in this context refers to the number of customers served by each retailer.
[47] ACIL Allen, *2021–22 regulated electricity price review – Updating retail costs*, final report prepared for the QCA, May 2021, Appendix B.
[48] EQ, sub. 3, pp. 13–14.
[49] Canegrowers, sub. 6, p. 2.
[50] As part of the 2020–25 regulatory determination process for Energex and Ergon Energy Network (distributors), the AER approved new network tariffs with more complex structures aimed at facilitating a move towards greater cost reflectivity. A number of new tariffs have already been introduced (and commenced on 1 July 2020), with additional new tariffs to be introduced (and commence) in the future.
[51] A grandfathered tariff is only available to existing customers but is closed to new customers.
[52] Two new demand network tariffs each for residential and small business customers.

charging window of the grandfathered network tariffs rather than the window for the new network tariffs. Conversely, for the demand tariffs, the charging parameters of the new network tariffs were adopted by most retailers. Some retailers also adopted their own charging windows/parameters, rather than the parameters associated with either the grandfathered or new network tariffs. For the load control tariffs, we also observed retailers adopting inconsistent strategies in passing through metering charges. These inconsistencies in retailers' strategies have made it difficult to assign appropriate network tariffs when undertaking the benchmarking analysis for the time-of-use, demand and load control tariffs.

Moreover, we do not have usage data for newly introduced network tariffs, including the new time-of-use and demand tariffs (since they were introduced on 1 July 2020). The most recent consumption and demand data available is for 2019–20. This contributed to the difficulties in estimating retail costs for these tariffs.

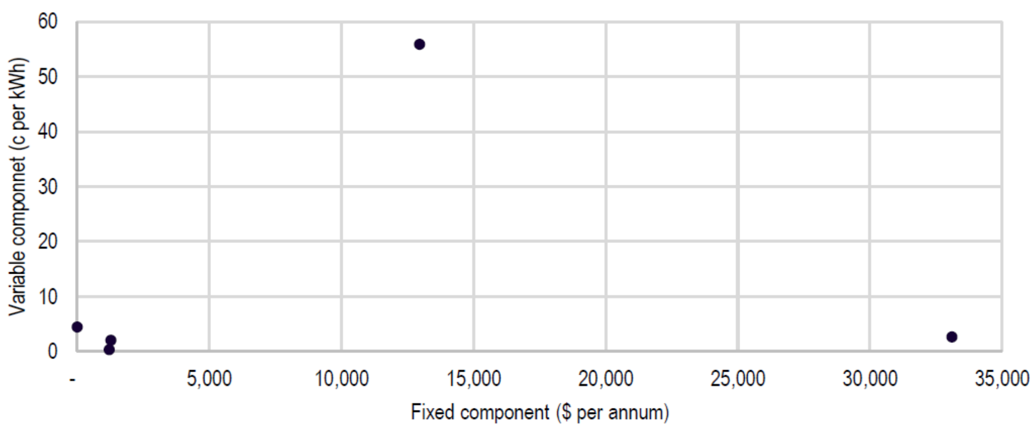
## Our consideration—retail costs for large customers

We considered establishing new allowances for large and very large customers but have maintained our approach for these customers due to data quality issues (discussed in section 4.2.2 of the main report).

ACIL Allen's bottom-up analysis was based on data provided by a small number of retailers in response to our information request. The data received were of varying completeness and highlighted differences in the way retailers categorise costs. For example, one of the five retailers expressed its retail costs with a variable (demand) component, while four of the five retailers expressed their retail costs with a fixed component and/or a variable (usage) component.

Additionally, the retail costs submitted by two of the retailers were significantly higher than submitted by the other three retailers, such that these estimates were removed from the analysis for large customers (see Figure 13).

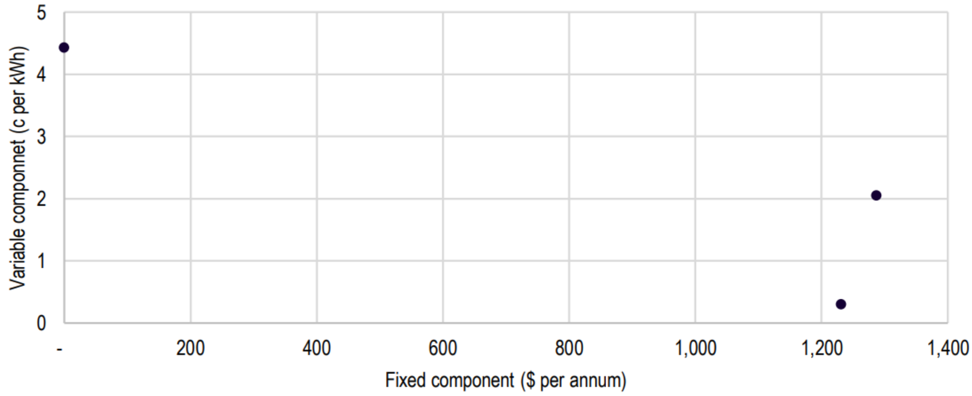
**Figure 13 Fixed and variable components of retail costs for large customers, 2020–21**




*Source: ACIL Allen analysis of confidential data provided by retailers. See ACIL Allen, 2021–22 regulated electricity price review – Updating retail costs, final report prepared for the QCA, May 2021.*

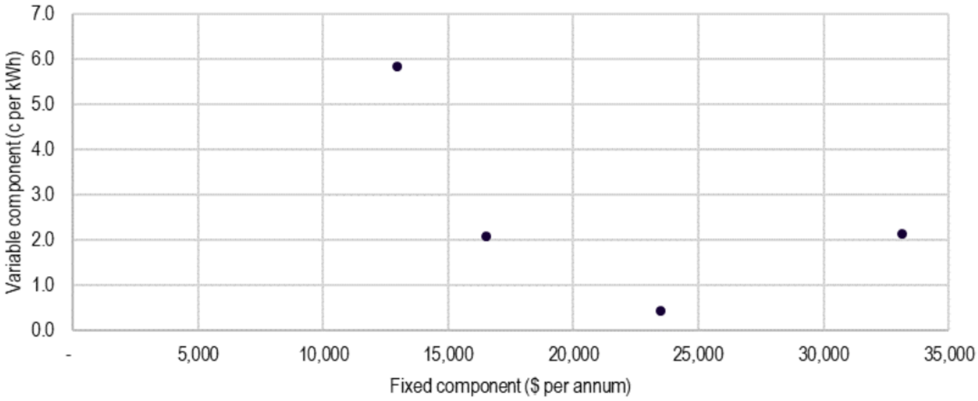
Even after removing these higher results, the fixed and variable components of the retail costs varied significantly across retailers. Figures 14 and 15 highlight the variability of the estimates produced for both large and very large customers.

**Figure 14 Fixed and variable components of retail costs for large customers (with anomalies removed), 2020–21**




*Source: ACIL Allen analysis of confidential data provided by retailers. See ACIL Allen, 2021–22 regulated electricity price review – Updating retail costs, final report prepared for the QCA, May 2021.*

**Figure 15 Fixed and variable components of retail costs for very large customers, 2020–21**




*Source: ACIL Allen analysis of confidential data provided by retailers. See ACIL Allen, 2021–22 regulated electricity price review – Updating retail costs, final report prepared for the QCA, May 2021.*

We acknowledge the potential for cost biases resulting from relying on self-reported retail data. Further, EQ expressed concern that the data it provided in relation to the 2020–21 financial year was largely a forecast, rather than being reflective of actual costs incurred.[53]

Overall, we consider it is more appropriate to maintain our current approach to updating the retail cost allowances for large and very large customers this year, due to the:

- limited number of data points—the estimates are based on three data points for large customers and four data points for very large customers
- variability of data—the figures above demonstrate the substantial variability of the fixed and variable components of the retail costs for large and very large customers among retailers
- reliability of data—relying on self-reported data from retailers may result in cost biases.

[53] EQ, sub. 3, p. 14.

The current approach relies upon the results of a more thorough investigation of the efficient level of retail costs and has been benchmarked against allowances in other regulatory decisions and public information on these costs.[54]

## Variable retail cost allocators for small customers

Consistent with our approach in 2016–17, the estimates for flat-rate tariffs have been used as the basis for calculating retail costs for all tariffs. For the calculation, we adopted the 2016–17 approach of determining a variable retail cost allocator to apply the variable retail cost estimates of flat-rate tariffs to all tariffs. Such an approach allows us to apply the variable retail cost allowance consistently across different tariff components, even when they are not expressed on a cents per kilowatt hour basis, such as the charging parameters for demand tariffs.

The allocator represents variable retail costs as a percentage of non-retail variable costs (such as energy and network costs). Using this approach means that the variable retail cost component changes in line with the underlying variable cost base.

Table 2 demonstrates how the allocators were calculated. The methodology is consistent with 2016–17 approach.

**Table 2 Variable retail costs allocators for small customers, 2021–22**

| | ***Benchmarked variable retail cost (c/kWh) (R)*** | ***Non- retail variable costs (c/kWh)*** | | | ***Variable cost allocator (%)*** |
|---|---|---|---|---|---|
| | | ***Network (N)*** | ***Energy (E)*** | ***Total (T=N+E)*** | ***(R/T)*** |
| Residential customer | 1.37 | 8.384 | 10.514 | 18.898 | 7.25 |
| Small business customer | 3.63 | 8.899 | 10.514 | 19.413 | 18.7 |

*Note: Energy and network charges are based on 2020–21 estimates to best align with ACIL Allen's benchmarking analysis, which predominantly uses the first quarter 2021 market offer data.*

*Source: QCA analysis using data from ACIL Allen.*

To derive the variable retail cost component of each tariff, we multiplied the underlying variable cost of each tariff (net of variable retail costs) by the appropriate allocator. The appropriate residential or small business allocator was applied based on the category of customer accessing that tariff.

[54] Frontier Economics, *Retail Operating Costs*, report for the Economic Regulation Authority of Western Australia, March 2012, p. 6.

# APPENDIX E: COST PASS-THROUGH APPROACH

This appendix provides further information on how we calculated the small-scale renewable energy scheme (SRES) pass-through amounts included in the notified prices (discussed in section 5.3).

The approach we used involves the following two steps:

- Estimate the under- or over-recovery of SRES costs in 2020–21.
- Calculate SRES costs to be passed through in the 2021–22 notified prices.

## Estimate the under- or over-recovery of SRES costs in 2020–21

First, we calculated the actual cost of SRES compliance during 2020–21, based on the Clean Energy Regulator's final small-scale technology percentage (STP) for 2020 and 2021.

We then compared the actual cost of SRES compliance to the SRES allowance in the 2020–21 notified prices, which revealed an under-recovery of $1.330/MWh (0.1330 c/kWh) (see Table 3).

**Table 3 SRES under-recovery, 2020–21**

| *2020–21* | *Period* | *STP* | | *Clearing house price ($/MWh)[a]* | *SRES cost ($/MWh)* | *Average SRES cost ($/MWh)* |
|---|---|---|---|---|---|---|
| | | *Final (%)* | *Non-binding (%)* | | | |
| Final determination allowance | 1 Jul–31 Dec 2020 | 24.40 | – | 40.00 | 9.760 | 9.310 |
| | 1 Jan–30 Jun 2021 | – | 22.15 | 40.00 | 8.860 | |
| Actual cost | 1 Jul–31 Dec 2020 | 24.40 | – | 40.00 | 9.760 | 10.640 |
| | 1 Jan–30 Jun 2021 | 28.80 | – | 40.00 | 11.520 | |
| Under-recovery in 2020–21 (before adjusting for energy losses, the time value of money, variable retail cost allocators and standing offer adjustment/headroom) | | | | | | 1.330 |

*a Determined by the Clean Energy Regulator.*

*Note: For presentation purposes, figures in this table have been rounded, so they may not add, subtract or multiply exactly.*

## Calculate SRES costs to be passed through in the 2021–22 notified prices

We adjusted the under-recovery amounts (described above) for:

- energy losses (to determine the SRES liabilities based on energy acquired), by applying the relevant transmission and distribution loss factors adopted in the 2020–21 determination
- the time value of money (to restore the real value of the under-recovered amounts), by applying a nominal weighted-average cost of capital of 6.45 per cent[55]
- the variable retail cost allocators and standing offer adjustment (consistent with the manner these allowances were applied as part of the 2020–21 determination).

Once the resulting pass-through amount is adjusted, it is included in the notified prices (see Table 4).

[55] Based on our latest internal analysis.

### Table 4 SRES pass-through amounts

| | | |
|---|---|---|
| **Energex net system load profile (NSLP)—residential (tariff 11 only)** | | |
| A | SRES under-recovery in 2020–21 (c/kWh) | 0.1330 |
| B | Energy losses in 2020–21 (total loss factor) | 1.060 |
| C | Discount rate (time value of money) (%) | 6.45 |
| D | Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2021–22 c/kWh) | 0.1501 |
| E | Variable retail cost allowance (residential) in 2020–21 (%) | 11.27 |
| F | Standing offer adjustment in 2020–21 (%) | 2.2 |
| G | SRES cost pass-through for 2021–22 (c/kWh) | 0.1707 |
| Energex NSLP and controlled load profiles (CLPs)—residential and load control[56] tariffs (excluding tariff 11) | | |
| A | SRES under-recovery in 2020–21 (c/kWh) | 0.1330 |
| B | Energy losses in 2020–21 (total loss factor) | 1.060 |
| C | Discount rate (time value of money) (%) | 6.45 |
| D | Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2021–22 c/kWh) | 0.1501 |
| E | Variable retail cost allowance (residential) in 2020–21 (%) | 11.27 |
| F | Standing offer adjustment in 2020–21 (%) | 5.0 |
| G | SRES cost pass-through for 2021–22 (c/kWh) | 0.1753 |
| Energex NSLP and CLPs—small business, load control[57] and unmetered supply tariffs | | |
| A | SRES under-recovery in 2020–21 (c/kWh) | 0.1330 |
| B | Energy losses in 2020–21 (total loss factor) | 1.060 |
| C | Discount rate (time value of money) (%) | 6.45 |
| D | Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2021–22 c/kWh) | 0.1501 |
| E | Variable retail cost allowance (small business) in 2020–21 (%) | 12.80 |
| F | Standing offer adjustment in 2020–21 (%) | 5.0 |
| G | SRES cost pass-through for 2021–22 (c/kWh) | 0.1777 |
| Ergon NSLP and CLPs—large business, load control[58] and street lighting tariffs | | |
| A | SRES under-recovery in 2020–21 (c/kWh) | 0.1330 |
| B | Energy losses in 2020–21 (total loss factor) | 1.053 |
| C | Discount rate (time value of money) (%) | 6.45 |
| D | Under-recovery before the application of headroom and variable retail cost allowance (2021–22 c/kWh) | 0.1491 |

[56] Tariffs 31 and 33.
[57] Tariff 34.
[58] Tariffs 60A and 60B.

| | | |
|---|---|---|
| E | Variable retail cost allowance (large business) in 2020–21 (%) | 6.0445 |
| F | Headroom allowance in 2020–21 (%) | 0.0 |
| G | SRES cost pass-through for 2021–22 (c/kWh) | 0.1581 |
| Ergon Energy NSLP—very large business tariffs | | |
| A | SRES under-recovery in 2020–21 (c/kWh) | 0.1330 |
| B | Energy losses in 2020–21 (total loss factor) | 0.993 |
| C | Discount rate (time value of money) (%) | 6.45 |
| D | Under-recovery before the application of headroom and variable retail cost allowance (2021–22 c/kWh) | 0.1406 |
| E | Variable retail cost allowance (very large business) in 2020–21 (%) | 6.0445 |
| F | Headroom allowance in 2020–21 (%) | 0.0 |
| G | SRES cost pass-through for 2021–22 (c/kWh) | 0. 1491 |

*Note: The SRES cost -pass-through amounts were calculated using the formula:* $G = A \times B \times (1 + C) \times (1 + E) \times (1 + F)$.

# APPENDIX F: DEFAULT MARKET OFFER COMPARISON

The delegation asks us to consider reducing the standing offer adjustment for small customers where the notified price bill (including a standing offer adjustment) would exceed the equivalent default market offer (DMO) reference bill in SEQ.

This appendix describes how we undertook a like-for-like comparison between the notified price bills and equivalent DMO reference bills. To undertake this comparison, we used the notified prices (including a 3.6 per cent standing offer adjustment[59]) and the AER's final DMO annual bills for 2021–22.

The AER has determined four DMO bills (for SEQ) for the following tariff groups—residential flat-rate tariff, residential flat-rate with load control tariffs, residential time-of-use tariff, and small business flat-rate tariff.[60]

Using the same approach we adopted last year, we have assessed the components of the DMO bill and notified price bill to undertake a like-for-like comparison. This included taking account of:

- metering costs, which are included in the DMO bills but not in our notified prices.[61] To undertake an equivalent comparison, we have excluded the value of metering costs (i.e. alternative control services charges) from the DMO bills
- GST, which is included in the DMO bills, but not in our notified prices. To ensure that the comparison is made on a like-for-like basis, we have excluded the value of GST from the DMO bills
- consumption levels, which are different for the DMO bills, compared to the levels we used to calculate our notified price bill impacts. To ensure that the bills are comparable, we have used the DMO consumption levels when calculating the equivalent notified price bills
- the AER's allocation for load control tariffs. To calculate a single DMO bill for both load control tariffs 31 and 33, the AER has used an apportioning approach with an allocation of 29 per cent for tariff 31 and 71 per cent for tariff 33. To undertake an equivalent comparison, we have applied the same approach as the AER to calculate a single notified price bill for load control tariffs (i.e. by using the AER's allocation methodology).

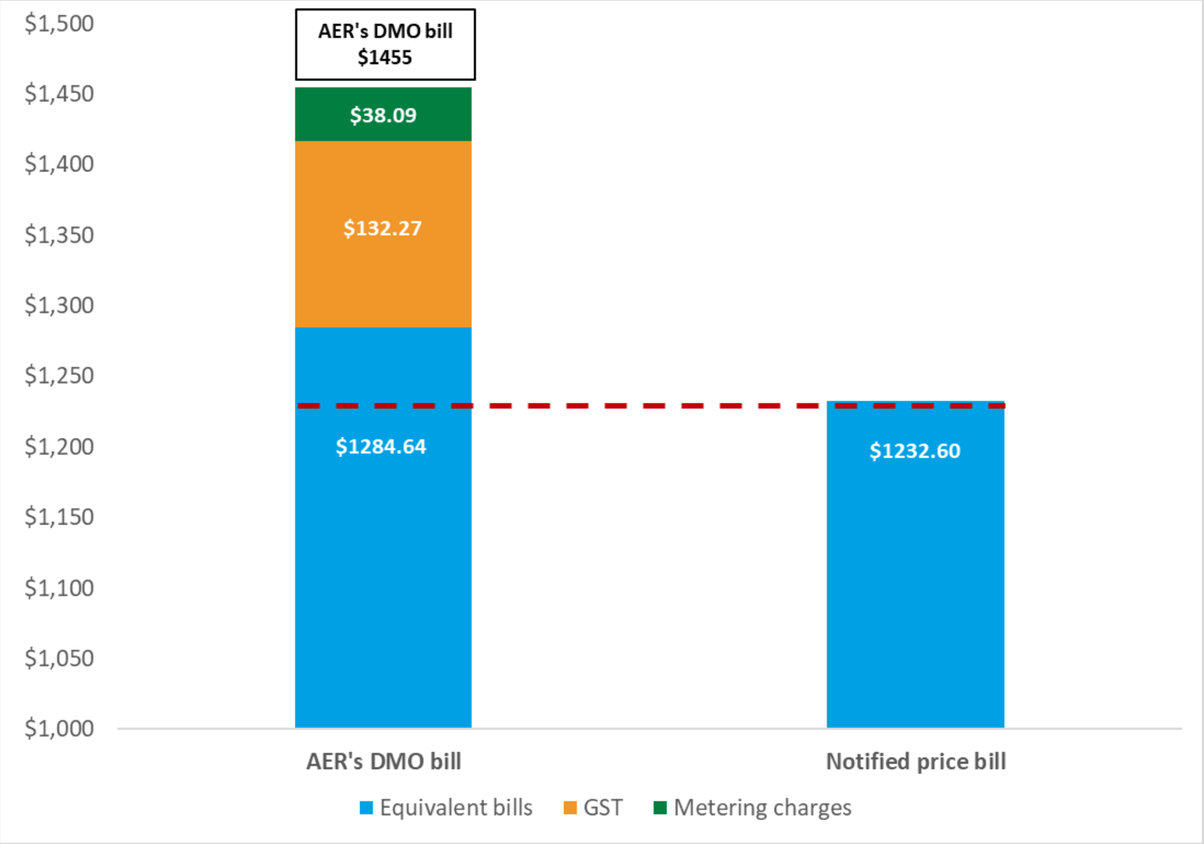
The like-for-like comparison between the notified price bills and equivalent DMO reference bills (after adjusting for the factors set out above) are shown in the charts below.

[59] See section 5.1 of the main report on the standing offer adjustment.
[60] AER, *Default Market Offer Prices 2021–22*, final determination, April 2021.
[61] We generally do not regulate metering charges for small customers (except for those on advanced digital meters). At this stage, most small customers in Queensland are on accumulation meters (only a small minority are on advanced digital meters).

## Residential flat-rate tariff (tariff 11)

The equivalent notified price bill (for tariff 11) is $52.04 lower than the DMO bill. Therefore, we do not need to adjust the notified price of tariff 11.

**Figure 16 Residential flat-rate tariff—equivalent annual bills**

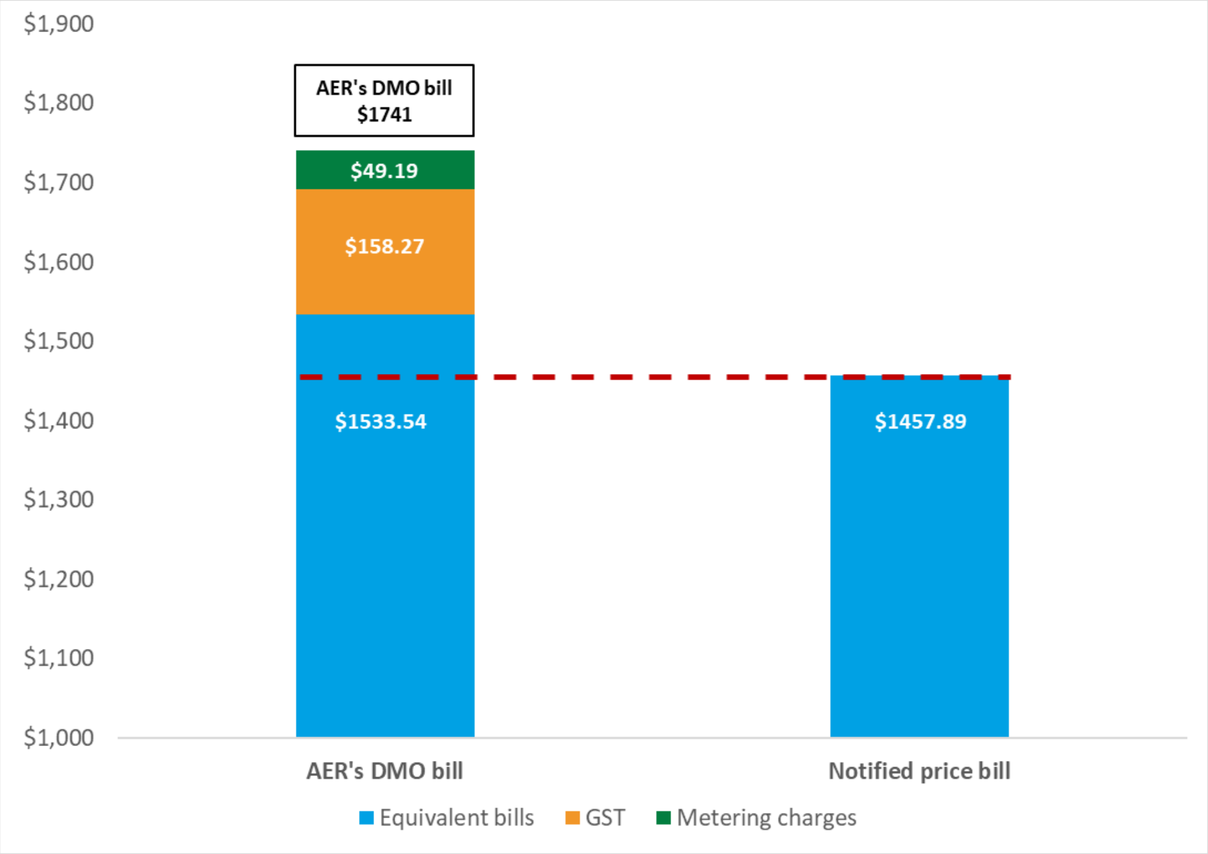



*Note: A DMO consumption level of 4600 kWh per annum was used to calculate the equivalent notified price bill.*

## Residential flat-rate with load control tariffs (tariffs 11, 31 and 33)

The equivalent notified price bill (for tariffs 11, 31 and 33) is $75.65 lower than the DMO bill. Therefore, no adjustment is necessary for the notified price of tariffs 31 and 33.

**Figure 17 Residential flat-rate with load control tariffs—equivalent annual bills**

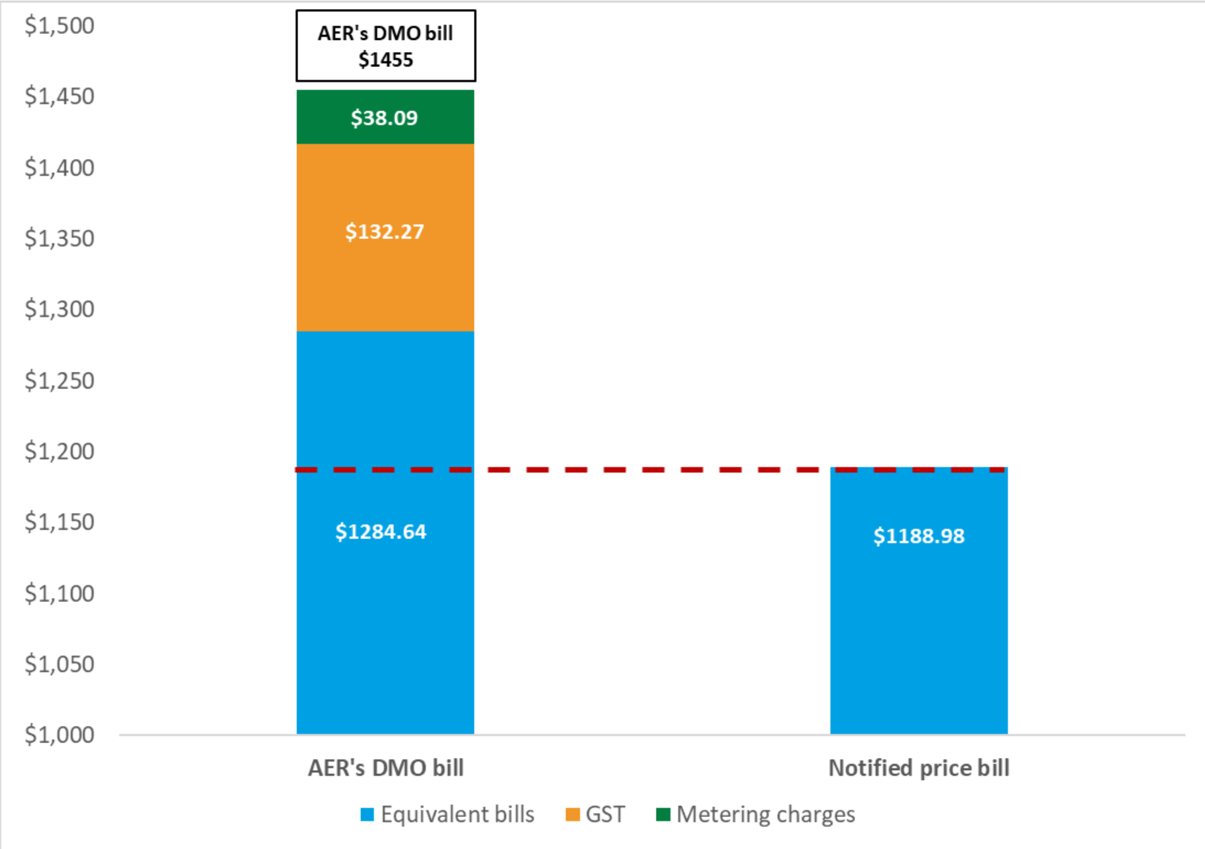



*Note: A DMO consumption level of 4400 kWh per annum (tariff 11) and 1900 kWh per annum (tariffs 31 and 33) were used to calculate the equivalent notified price bill. Applying the AER's allocation methodology resulted in a consumption level of 551 kWh per annum for tariff 31 (29 per cent of 1900 kWh per annum) and 1,349 kWh per annum for tariff 33 (71 per cent of 1900 kWh per annum).*

## Residential time-of-use tariff (tariff 12B)

Among the suite of time-of-use tariffs, we consider tariff 12B to be comparable to the DMO residential time-of-use tariff, as tariff 12B is based on the Energex time-of-use network tariff in SEQ. The equivalent notified price bill (for tariff 12B) is $95.66 lower than the DMO bill. As such, no adjustment is required to the notified price of tariff 12B.

**Figure 18 Residential time-of-use tariff—equivalent annual bills**

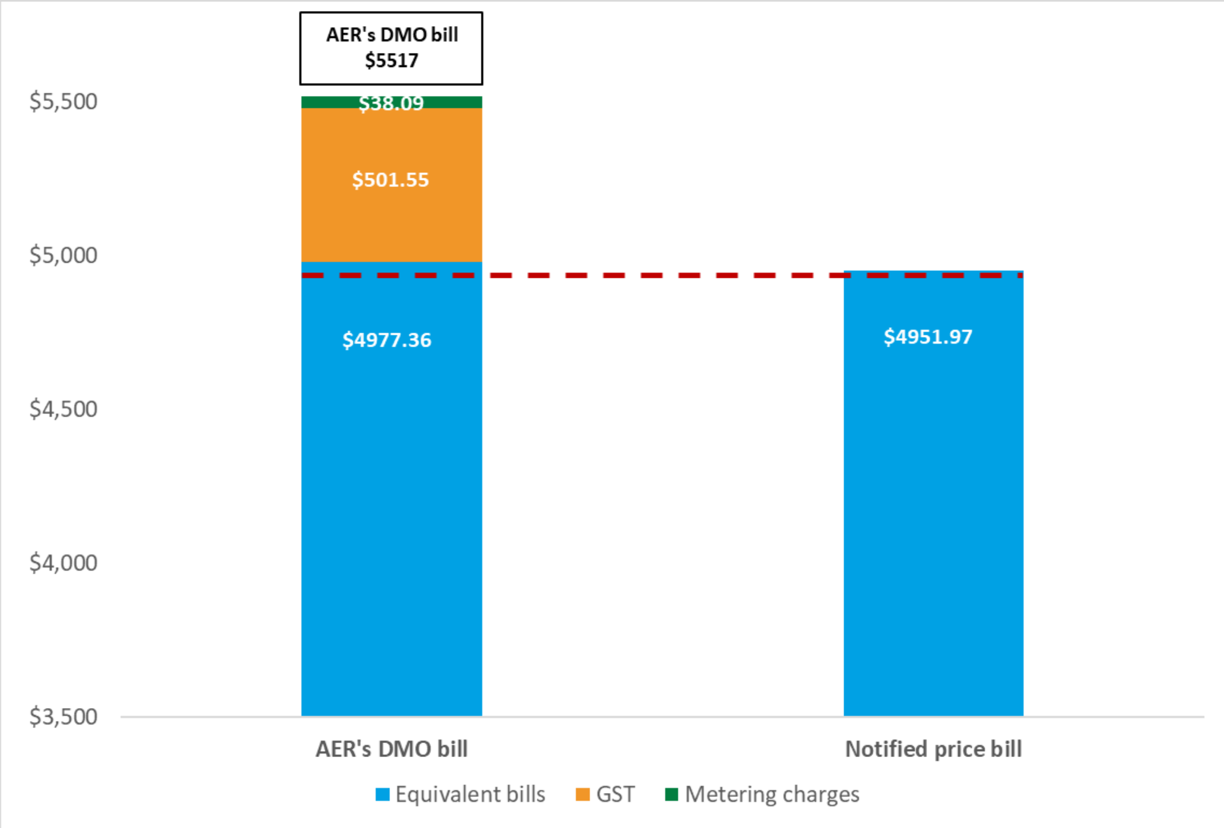



*Note: The AER's DMO pattern of supply for a time-of-use tariff was used to calculate the equivalent notified price bill.*

## Small business flat-rate tariff (tariff 20)

The equivalent notified price bill for (tariff 20) is $25.39 lower than the DMO bill. Hence, no further adjustment to the notified price of tariff 20 is required.

**Figure 19 Small business flat-rate tariff—equivalent annual bills**




*Note: A DMO consumption level of 20000 kWh per annum was used to calculate the equivalent notified price bill.*

# APPENDIX G: DATA USED TO ESTIMATE CUSTOMER IMPACTS

Typical customer figures are based on the annual consumption of the median customer on each tariff in regional Queensland. The median customer is the middle customer in terms of consumption out of all customers on each tariff. As such, half of all customers will use less electricity than the median figure, and half will use more.

Consistent with previous determinations, Energy Queensland provided estimated usage for tariff 22A, while Ergon Energy Retail (Ergon Retail) provided the latest actual usage data for the remaining tariffs, gathered from their customer base of over 700,000 electricity customers in regional Queensland.

**Table 5 Median usage data used to determine customer impacts**

| ***Retail tariff*** | ***Usage (kWh per year)*** | ***Peak usage*** | ***Off-peak usage*** | ***Demand (kW per month)*** | ***Demand threshold (kW per month)*** |
|---|---|---|---|---|---|
| T11 | 4,210 | | | | |
| T31 | 1,249 | | | | |
| T33 | 953 | | | | |
| T20 | 6,443 | | | | |
| T22A | 7,457 | 16.7% | 83.3% | | |
| T44 | 139,921 | | | 70 | 30 |
| T45 | 690,163 | | | 188 | 120 |
| T46 | 1,560,774 | | | 488 | 400 |

# APPENDIX H: BUILD-UP OF NOTIFIED PRICES

**Table 6 Notified prices—residential customers (GST excl.)**

| *Retail tariff* | *Tariff component* | *Fixed*[a] | *Usage* | | | *Demand* | |
|---|---|---|---|---|---|---|---|
| | | | *Off-peak/flat* | *Shoulder* | *Peak* | *Off-peak/flat* | *Peak* |
| | | *c/day* | *c/kWh* | *c/kWh* | *c/kWh* | *$/kW/mth* | *$/kW/mth* |
| Tariff 11—residential (flat-rate) | Network | 51.400 | 8.468 | | | | |
| | Energy | | 9.183 | | | | |
| | Fixed retail | 33.920 | | | | | |
| | Variable retail | | 1.280 | | | | |
| | Standing offer adjustment | 3.072 | 0.681 | | | | |
| | SRES cost pass-through | | 0.1707 | | | | |
| | **Total** | **88.392** | **19.782** | | | | |
| Tariff 12A—residential (time-of-use) | Network | 33.615 | 5.475 | | 36.793 | | |
| | Energy | | 9.183 | | 9.183 | | |
| | Fixed retail | 33.920 | | | | | |
| | Variable retail | | 1.063 | | 3.333 | | |
| | Standing offer adjustment | 2.431 | 0.566 | | 1.775 | | |
| | SRES cost pass-through | | 0.1753 | | 0.1753 | | |
| | **Total** | **69.967** | **16.461** | | **51.260** | | |
| Tariff 12B—residential time-of-use | Network | 51.400 | 3.857 | 5.418 | 14.277 | | |
| | Energy | | 9.183 | 9.183 | 9.183 | | |
| | Fixed retail | 33.920 | | | | | |
| | Variable retail | | 0.945 | 1.059 | 1.701 | | |
| | Standing offer adjustment | 3.072 | 0.503 | 0.564 | 0.906 | | |
| | SRES cost pass-through | | 0.1753 | 0.1753 | 0.1753 | | |
| | **Total** | **88.392** | **14.664** | **16.398** | **26.241** | | |
| Tariff 14—residential (seasonal time-of-use demand) | Network | 7.545 | 2.431 | | | 6.303 | 43.892 |
| | Energy | | 9.183 | | | | |
| | Fixed retail | 33.920 | | | | | |
| | Variable retail | | 0.842 | | | 0.457 | 3.182 |

| ***Retail tariff*** | ***Tariff component*** | ***Fixed[a]*** | ***Usage*** | | | ***Demand*** | |
|---|---|---|---|---|---|---|---|
| | | | ***Off-peak/flat*** | ***Shoulder*** | ***Peak*** | ***Off-peak/flat*** | ***Peak*** |
| | | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***c/kWh*** | ***$/kW/mth*** | ***$/kW/mth*** |
| | Standing offer adjustment | 1.493 | 0.448 | | | 0.243 | 1.695 |
| | SRES cost pass-through | | 0.1753 | | | | |
| | **Total** | **42.958** | **13.079** | | | **7.004** | **48.769** |
| Tariff 14A—residential time-of-use demand | Network | 50.300 | 5.786 | | | 2.307 | |
| | Energy | | 9.183 | | | | |
| | Fixed retail | 33.920 | | | | | |
| | Variable retail | | 1.085 | | | 0.167 | |
| | Standing offer adjustment | 3.032 | 0.578 | | | 0.089 | |
| | SRES cost pass-through | | 0.1753 | | | | |
| | Total | **87.252** | **16.807** | | | **2.563** | |
| Tariff 14B—residential time-of-use demand | Network | 50.300 | 3.300 | | | 6.588 | |
| | Energy | | 9.183 | | | | |
| | Fixed retail | 33.920 | | | | | |
| | Variable retail | | 0.905 | | | 0.478 | |
| | Standing offer adjustment | 3.032 | 0.482 | | | 0.254 | |
| | SRES cost pass-through | | 0.1753 | | | | |
| | **Total** | **87.252** | **14.045** | | | **7.320** | |
| Tariff 31—night rate (super economy) | Network | | 3.920 | | | | |
| | Energy | | 7.645 | | | | |
| | Fixed retail | | | | | | |
| | Variable retail | | 0.838 | | | | |
| | Standing offer adjustment | | 0.447 | | | | |
| | SRES cost pass-through | | 0.1753 | | | | |
| | **Total** | | **13.026** | | | | |
| Tariff 33—controlled (supply economy) | Network | | 4.920 | | | | |
| | Energy | | 7.804 | | | | |
| | Fixed retail | | | | | | |
| | Variable retail | | 0.923 | | | | |

| *Retail tariff* | *Tariff component* | *Fixed[a]* | *Usage* | | | *Demand* | |
|---|---|---|---|---|---|---|---|
| | | | *Off-peak/flat* | *Shoulder* | *Peak* | *Off-peak/flat* | *Peak* |
| | | *c/day* | *c/kWh* | *c/kWh* | *c/kWh* | *$/kW/mth* | *$/kW/mth* |
| | Standing offer adjustment | | 0.491 | | | | |
| | SRES cost pass-through | | 0.1753 | | | | |
| | **Total** | | **14.313** | | | | |

***a*** *Charged per metering point.*

*Note: Totals may not add due to rounding.*

## Table 7 Notified prices—small business and unmetered supply customers (GST excl.)

| *Retail tariff* | *Tariff component* | *Fixed[a]* | *Usage* | | *Demand* | |
|---|---|---|---|---|---|---|
| | | | *Off-peak/flat* | *Peak* | *Off-peak/flat* | *Peak* |
| | | *c/day* | *c/kWh* | *c/kWh* | *$/kW/mth* | *$/kW/mth* |
| Tariff 20—business (flat-rate) | Network | 69.400 | 9.011 | | | |
| | Energy | | 9.183 | | | |
| | Fixed retail | 47.426 | | | | |
| | Variable retail | | 3.402 | | | |
| | Standing offer adjustment | 4.206 | 0.777 | | | |
| | SRES cost pass-through | | 0.1777 | | | |
| | **Total** | **121.032** | **22.551** | | | |
| Tariff 22A—business (seasonal time-of-use) | Network | 58.950 | 7.555 | 34.961 | | |
| | Energy | | 9.183 | 9.183 | | |
| | Fixed retail | 47.426 | | | | |
| | Variable retail | | 3.130 | 8.255 | | |
| | Standing offer adjustment | 3.830 | 0.715 | 1.886 | | |
| | SRES cost pass-through | | 0.1777 | 0.1777 | | |
| | **Total** | **110.206** | **20.760** | **54.463** | | |
| Tariff 24—business (seasonal time-of-use demand) | Network | 8.162 | 3.082 | | 5.998 | 59.689 |
| | Energy | | 9.183 | | | |
| | Fixed retail | 47.426 | | | | |
| | Variable retail | | 2.293 | | 1.122 | 11.162 |
| | Standing offer adjustment | 2.001 | 0.524 | | 0.256 | 2.551 |

| ***Retail tariff*** | ***Tariff component*** | ***Fixed[a]*** | ***Usage*** | | ***Demand*** | |
|---|---|---|---|---|---|---|
| | | | ***Off-peak/flat*** | ***Peak*** | ***Off-peak/flat*** | ***Peak*** |
| | | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***$/kW/mth*** | ***$/kW/mth*** |
| | SRES cost pass-through | | 0.1777 | | | |
| | **Total** | **57.590** | **15.260** | | **7.376** | **73.402** |
| Tariff 24A—business (time-of-use demand) | Network | 68.200 | 7.890 | | 1.953 | |
| | Energy | | 9.183 | | | |
| | Fixed retail | 47.426 | | | | |
| | Variable retail | | 3.193 | | 0.365 | |
| | Standing offer adjustment | 4.163 | 0.730 | | 0.083 | |
| | SRES cost pass-through | | 0.1777 | | | |
| | **Total** | **119.789** | **21.172** | | **2.402** | |
| Tariff 24B—business (time-of-use demand) | Network | 68.200 | 5.855 | | 7.790 | |
| | Energy | | 9.183 | | | |
| | Fixed retail | 47.426 | | | | |
| | Variable retail | | 2.812 | | 1.457 | |
| | Standing offer adjustment | 4.163 | 0.643 | | 0.333 | |
| | SRES cost pass-through | | 0.1777 | | | |
| | **Total** | **119.789** | **18.670** | | **9.580** | |
| Tariff 34—business (interruptible supply) | Network | 59.700 | 5.199 | | | |
| | Energy | | 8.222 | | | |
| | Fixed retail | 47.426 | | | | |
| | Variable retail | | 2.510 | | | |
| | Standing offer adjustment | 3.857 | 0.574 | | | |
| | SRES cost pass-through | | 0.1777 | | | |
| | **Total** | **110.983** | **16.682** | | | |
| Tariff 41—business low voltage (demand) | Network | 556.400 | 1.804 | | 14.922 | |
| | Energy | | 9.183 | | | |
| | Fixed retail | 47.426 | | | | |
| | Variable retail | | 2.054 | | 2.790 | |
| | Standing offer adjustment | 21.738 | 0.469 | | 0.638 | |

| ***Retail tariff*** | ***Tariff component*** | ***Fixed[a]*** | ***Usage*** | | ***Demand*** | |
|---|---|---|---|---|---|---|
| | | | ***Off-peak/flat*** | ***Peak*** | ***Off-peak/flat*** | ***Peak*** |
| | | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***$/kW/mth*** | ***$/kW/mth*** |
| | SRES cost pass-through | | 0.1777 | | | |
| | **Total** | **625.564** | **13.688** | | **18.350** | |
| Tariff 91—unmetered | Network | | 6.459 | | | |
| | Energy | | 9.183 | | | |
| | Fixed retail | | | | | |
| | Variable retail | | 2.925 | | | |
| | Standing offer adjustment | | 0.668 | | | |
| | SRES cost pass-through | | 0.1777 | | | |
| | **Total** | | **19.413** | | | |

***a*** *Charged per metering point.*

*Note: Totals may not add up precisely due to rounding.*

## Table 8 Notified prices—small business customers (GST excl.)

| ***Retail tariff*** | ***Tariff component*** | ***Fixed band[a]*** | | | | | ***Usage*** | | |
|---|---|---|---|---|---|---|---|---|---|
| | | ***Band 1*** | ***Band 2*** | ***Band 3*** | ***Band 4*** | ***Band 5*** | ***Off-peak/flat*** | ***Shoulder*** | ***Peak*** |
| | | ***c/day*** | ***c/day*** | ***c/day*** | ***c/day*** | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***c/kWh*** |
| Tariff 20A—small business inclining-band | Network | 69.400 | 97.700 | 126.100 | 154.500 | 182.900 | 9.011 | | |
| | Energy | | | | | | 9.183 | | |
| | Fixed retail | 47.426 | 47.426 | 47.426 | 47.426 | 47.426 | | | |
| | Variable retail | | | | | | 3.402 | | |
| | Standing offer adjustment | 4.206 | 5.225 | 6.247 | 7.269 | 8.292 | 0.777 | | |
| | SRES cost pass-through | | | | | | 0.1777 | | |
| | **Total** | **121.032** | **150.351** | **179.773** | **209.196** | **238.618** | **22.551** | | |
| Tariff 22B—small business time-of-use inclining band | Network | 69.400 | 97.700 | 126.100 | 154.500 | 182.900 | 5.861 | 8.284 | 15.701 |
| | Energy | | | | | | 9.183 | 9.183 | 9.183 |
| | Fixed retail | 47.426 | 47.426 | 47.426 | 47.426 | 47.426 | | | |
| | Variable retail | | | | | | 2.813 | 3.266 | 4.653 |
| | Standing offer adjustment | 4.206 | 5.225 | 6.247 | 7.269 | 8.292 | 0.643 | 0.746 | 1.063 |
| | SRES cost pass-through | | | | | | 0.1777 | 0.1777 | 0.1777 |
| | **Total** | **121.032** | **150.351** | **179.773** | **209.196** | **238.618** | **18.677** | **21.657** | **30.778** |

***a*** *Charged per metering point.*

*Note: Totals may not add up precisely due to rounding.*

## Table 9 Notified prices—large business and street lighting customers (GST excl.)

| *Retail tariff* | *Tariff component* | *Fixed*[a] | *Usage* | | *Demand* | | | *Excess Demand* |
|---|---|---|---|---|---|---|---|---|
| | | | *Off-peak/flat* | *Peak* | *Off-peak/flat* | *Peak* | *Flat* | |
| | | *c/day* | *c/kWh* | *c/kWh* | *$/kW/mth* | *$/kW/mth* | *$/kVA/mth* | *$/kVA/mth* |
| Tariff 44—over 100 MWh small (demand) | Network | 3662.700 | 1.685 | | 24.565 | | 22.108 | |
| | Energy | | 8.407 | | | | | |
| | Fixed retail | 385.984 | | | | | | |
| | Variable retail | | 0.610 | | 1.485 | | 1.336 | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | 0.1581 | | | | | |
| | **Total** | **4048.684** | **10.860** | | **26.050** | | **23.444** | |
| Tariff 45—over 100 MWh medium (demand) | Network | 12070.800 | 1.685 | | 19.921 | | 17.929 | |
| | Energy | | 8.407 | | | | | |
| | Fixed retail | 1061.511 | | | | | | |
| | Variable retail | | 0.610 | | 1.204 | | 1.084 | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | 0.1581 | | | | | |
| | **Total** | **13132.311** | **10.860** | | **21.125** | | **19.013** | |
| Tariff 46—over 100 MWh large (demand) | Network | 31522.900 | 1.685 | | 16.333 | | 14.699 | |
| | Energy | | 8.407 | | | | | |
| | Fixed retail | 2700.282 | | | | | | |
| | Variable retail | | 0.610 | | 0.987 | | 0.888 | |
| | Headroom | | | | | | | |

| *Retail tariff* | *Tariff component* | *Fixed*[a] | *Usage* | | *Demand* | | | *Excess Demand* |
|---|---|---|---|---|---|---|---|---|
| | | | *Off-peak/flat* | *Peak* | *Off-peak/flat* | *Peak* | *Flat* | |
| | | *c/day* | *c/kWh* | *c/kWh* | *$/kW/mth* | *$/kW/mth* | *$/kVA/mth* | *$/kVA/mth* |
| | SRES cost pass-through | | 0.1581 | | | | | |
| | **Total** | **34223.182** | **10.860** | | **17.320** | | **15.587** | |
| Tariff 50—over 100 MWh seasonal time-of-use (demand) | Network | 3066.200 | 3.564 | 1.337 | 9.950 | 64.197 | | |
| | Energy | | 8.407 | 8.407 | | | | |
| | Fixed retail | 347.613 | | | | | | |
| | Variable retail | | 0.724 | 0.589 | 0.601 | 3.880 | | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | 0.1581 | 0.1581 | | | | |
| | **Total** | **3413.813** | **12.852** | **10.491** | **10.551** | **68.077** | | |
| Tariff 50A—large business time-of-use demand | Network | 15469.300 | 2.091 | | | | 12.808 | 2.562 |
| | Energy | | 8.407 | | | | | |
| | Fixed retail | 347.613 | | | | | | |
| | Variable retail | | 0.635 | | | | 0.774 | 0.155 |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | 0.1581 | | | | | |
| | **Total** | **15816.913** | **11.290** | | | | **13.582** | **2.717** |
| Tariff 60A—large business flat-rate interruptible supply (primary) | Network | 3662.700 | 9.516 | | | | | |
| | Energy | | 7.742 | | | | | |
| | Fixed retail | 385.984 | | | | | | |
| | Variable retail | | 1.043 | | | | | |

| ***Retail tariff*** | ***Tariff component*** | ***Fixed[a]*** | ***Usage*** | | ***Demand*** | | | ***Excess Demand*** |
|---|---|---|---|---|---|---|---|---|
| | | | ***Off-peak/flat*** | ***Peak*** | ***Off-peak/flat*** | ***Peak*** | ***Flat*** | |
| | | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***$/kW/mth*** | ***$/kW/mth*** | ***$/kVA/mth*** | ***$/kVA/mth*** |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | 0.1581 | | | | | |
| | **Total** | **4048.684** | **18.459** | | | | | |
| Tariff 60B—large business flat-rate interruptible supply (secondary) | Network | | 9.516 | | | | | |
| | Energy | | 7.742 | | | | | |
| | Fixed retail | | | | | | | |
| | Variable retail | | 1.043 | | | | | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | 0.1581 | | | | | |
| | **Total** | | **18.459** | | | | | |
| Tariff 71—street lighting | Network | | 13.859 | | | | | |
| | Energy | | 8.407 | | | | | |
| | Fixed retail | | | | | | | |
| | Variable retail | | 1.346 | | | | | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | 0.1581 | | | | | |
| | **Total** | | **23.770** | | | | | |

***a*** *Charged per metering point.*

*Note: Totals may not add up precisely due to rounding.*

## Table 10 Notified prices—very large business customers (GST excl.)

| *Retail tariff* | *Tariff component* | *Fixed*[a] | *Usage* | *Connection unit* | *Capacity* | *Demand* |
|---|---|---|---|---|---|---|
| | | *c/day* | *c/kWh* | *$/day/unit* | *$/kVA of AD/mth* | *$/kVA/mth* |
| Tariff 51A—high voltage (CAC 66 kV) | Network | 22833.800 | 1.449 | 5.527 | 3.284 | 3.014 |
| | Energy | | 8.090 | | | |
| | Fixed retail | 2672.986 | | | | |
| | Variable retail | | 0.577 | 0.334 | 0.199 | 0.182 |
| | Headroom | | | | | |
| | SRES cost pass-through | | 0.1491 | | | |
| | **Total** | **25506.786** | **10.265** | **5.861** | **3.483** | **3.196** |
| Tariff 51B—high voltage (CAC 33 kV) | Network | 16303.200 | 1.449 | 5.527 | 4.001 | 3.122 |
| | Energy | | 8.090 | | | |
| | Fixed retail | 2672.986 | | | | |
| | Variable retail | | 0.577 | 0.334 | 0.242 | 0.189 |
| | Headroom | | | | | |
| | SRES cost pass-through | | 0.1491 | | | |
| | **Total** | **18976.186** | **10.265** | **5.861** | **4.243** | **3.311** |
| Tariff 51C—high voltage (CAC 22/11kV Bus) | Network | 15172.000 | 1.449 | 5.527 | 4.606 | 3.786 |
| | Energy | | 8.090 | | | |
| | Fixed retail | 2672.986 | | | | |
| | Variable retail | | 0.577 | 0.334 | 0.278 | 0.229 |
| | Headroom | | | | | |
| | SRES cost pass-through | | 0.1491 | | | |

| *Retail tariff* | *Tariff component* | *Fixed[a]* | *Usage* | *Connection unit* | *Capacity* | *Demand* |
|---|---|---|---|---|---|---|
| | | *c/day* | *c/kWh* | *$/day/unit* | *$/kVA of AD/mth* | *$/kVA/mth* |
| | **Total** | **17844.986** | **10.265** | **5.861** | **4.884** | **4.015** |
| Tariff 51D— high voltage (CAC 22/11kV Line) | Network | 14525.600 | 1.449 | 5.527 | 8.886 | 7.636 |
| | Energy | | 8.090 | | | |
| | Fixed retail | 2672.986 | | | | |
| | Variable retail | | 0.577 | 0.334 | 0.537 | 0.462 |
| | Headroom | | | | | |
| | SRES cost pass-through | | 0.1491 | | | |
| | **Total** | **17198.586** | **10.265** | **5.861** | **9.423** | **8.098** |
| Tariff 53—high voltage (ICC) | Network | 22833.800 | 1.449 | | 3.284 | 3.014 |
| | Energy | | 8.090 | | | |
| | Fixed retail | 2488.271 | | | | |
| | Variable retail | | 0.577 | | 0.199 | 0.182 |
| | Headroom | | | | | |
| | SRES cost pass-through | | 0.1491 | | | |
| | **Total** | **25322.071** | **10.265** | | **3.483** | **3.196** |
| ICC site-specific—high voltage | Energy | | 8.090 | | | |
| | Fixed retail | 2488.271 | | | | |
| | Variable retail | | 0.577 | | 0.199 | 0.182 |
| | Headroom | | | | | |
| | SRES cost pass-through | | 0.1491 | | | |
| | **Total** | **2488.271** | **8.816** | | **0.199** | **0.182** |

***a*** *Charged per metering point.*

*Note: Totals may not add up precisely due to rounding.*

**Table 11 Notified prices—very large business customers (GST excl.)**

| *Retail tariff* | *Tariff component* | *Fixed*[a] | *Usage* | | *Connection unit* | *Capacity* | *Demand* |
|---|---|---|---|---|---|---|---|
| | | | *Off-peak* | *Peak* | | | |
| | | *c/day* | *c/kWh* | *c/kWh* | *$/day/unit* | *$/kVA of AD/mth* | *$/kVA/mth* |
| Tariff 52A—high voltage (CAC STOUD 33-66kV) | Network | 11859.200 | 1.381 | 1.055 | 5.527 | 5.650 | 11.728 |
| | Energy | | 8.090 | 8.090 | | | |
| | Fixed retail | 2672.986 | | | | | |
| | Variable retail | | 0.572 | 0.553 | 0.334 | 0.342 | 0.709 |
| | Headroom | | | | | | |
| | SRES cost pass-through | | 0.1491 | 0.1491 | | | |
| | **Total** | **14532.186** | **10.193** | **9.847** | **5.861** | **5.992** | **12.437** |
| Tariff 52B—high voltage (CAC STOUD 22/11kV Bus) | Network | 11859.200 | 1.381 | 1.055 | 5.527 | 4.006 | 44.225 |
| | Energy | | 8.090 | 8.090 | | | |
| | Fixed retail | 2672.986 | | | | | |
| | Variable retail | | 0.572 | 0.553 | 0.334 | 0.242 | 2.673 |
| | Headroom | | | | | | |
| | SRES cost pass-through | | 0.1491 | 0.1491 | | | |
| | **Total** | **14532.186** | **10.193** | **9.847** | **5.861** | **4.248** | **46.898** |
| Tariff 52C—high voltage (CAC STOUD 22/11kV Line) | Network | 11859.200 | 1.381 | 1.055 | 5.527 | 7.294 | 72.184 |
| | Energy | | 8.090 | 8.090 | | | |
| | Fixed retail | 2672.986 | | | | | |
| | Variable retail | | 0.572 | 0.553 | 0.334 | 0.441 | 4.363 |

| ***Retail tariff*** | ***Tariff component*** | ***Fixed[a]*** | ***Usage*** | | ***Connection unit*** | ***Capacity*** | ***Demand*** |
|---|---|---|---|---|---|---|---|
| | | | ***Off-peak*** | ***Peak*** | | | |
| | | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***$/day/unit*** | ***$/kVA of AD/mth*** | ***$/kVA/mth*** |
| | Headroom | | | | | | |
| | SRES cost pass-through | | 0.1491 | 0.1491 | | | |
| | **Total** | **14532.186** | **10.193** | **9.847** | **5.861** | **7.735** | **76.547** |

***a*** *Charged per metering point.*

*Note: Totals may not add up precisely due to rounding.*

## Table 12 Notified prices—large business customers (GST excl.)

| ***Retail tariff*** | ***Tariff component*** | ***Fixed[a]*** | ***Usage[b]*** | |
|---|---|---|---|---|
| | | | ***Below threshold*** | ***Above threshold*** |
| | | ***c/day*** | ***c/kWh*** | ***c/kWh*** |
| Tariff 43—Business customer (over 100 MWh) | Network | 3662.700 | 1.685 | 9.159 |
| | Energy | | 8.407 | 8.407 |
| | Fixed retail | 385.984 | | |
| | Variable retail | | 0.610 | 1.062 |
| | Headroom | | | |
| | SRES cost pass-through | | | |
| | **Total** | **4048.684** | **10.702** | **18.628** |

***a*** *Charged per metering point.*

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

*Note: Totals may not add up precisely due to rounding.*

## Table 13 Limited-access obsolete tariffs—small business customers (GST excl.)

| *Retail tariff* | *Tariff component* | *Fixed[a]* | *Usage* | | | *Capacity* | |
|---|---|---|---|---|---|---|---|
| | | | *Block 1/ Peak* | *Block 2* | *Off-peak/flat* | *Up to 7.5kW* | *Over 7.5kW* |
| | | *c/day* | *c/kWh* | *c/kWh* | *c/kWh* | *$/kW* | *$/kW* |
| Tariff 62A—time-of-use declining block tariff[b] | Network | 55.600 | 36.212 | 28.925 | 5.699 | | |
| | Energy | | 8.407 | 8.407 | 8.407 | | |
| | Fixed retail | 47.870 | | | | | |
| | Variable retail | | 8.344 | 6.981 | 2.638 | | |
| | Headroom | | | | | | |
| | SRES cost pass-through | | | | | | |
| | **Total** | **103.470** | **52.963** | **44.313** | **16.744** | | |
| Tariff 65A—time-of-use tariff[c] | Network | 55.400 | 26.545 | | 9.683 | | |
| | Energy | | 8.407 | | 8.407 | | |
| | Fixed retail | 47.870 | | | | | |
| | Variable retail | | 6.536 | | 3.383 | | |
| | Headroom | | | | | | |
| | SRES cost pass-through | | | | | | |
| | **Total** | **103.270** | **41.488** | | **21.473** | | |
| Tariff 66A—dual-rate demand tariff | Network | 162.800 | | | 8.645 | 3.154 | 9.522 |
| | Energy | | | | 8.407 | | |
| | Fixed retail | 47.870 | | | | | |
| | Variable retail | | | | 3.189 | 0.590 | 1.781 |
| | Headroom | | | | | | |

| ***Retail tariff*** | ***Tariff component*** | ***Fixed[a]*** | ***Usage*** | | | ***Capacity*** | |
|---|---|---|---|---|---|---|---|
| | | | ***Block 1/ Peak*** | ***Block 2*** | ***Off-peak/flat*** | ***Up to 7.5kW*** | ***Over 7.5kW*** |
| | | ***c/day*** | ***c/kWh*** | ***c/kWh*** | ***c/kWh*** | ***$/kW*** | ***$/kW*** |
| | SRES cost pass-through | | | | | | |
| | **Total** | **210.670** | | | **20.240** | **3.744** | **11.303** |

***a*** *Charged per metering point.*

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

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

*Note: Totals may not add up precisely due to rounding.*

# APPENDIX I: GAZETTE NOTICE

## Queensland Government Gazette

***Electricity Act 1994***

**RETAIL ELECTRICITY PRICES FOR STANDARD CONTRACT CUSTOMERS**

This Gazette notice replaces the Retail Electricity Prices for Standard Contract Customers notice dated 11 December 2020.

The notified prices are the prices decided under section 90(1) of the *Electricity Act 1994* (the Electricity Act).

A retailer must charge its Standard Contract Customers, as defined in the Electricity Act, the notified prices subject to the provisions of sections 91, 91A and 91AA of the Electricity Act and section 22A, Division 12A of Part 2 of the *National Energy Retail Law (Queensland)* (the NERL (Qld)).

Pursuant to the Certificate of Delegation from the Minister for Energy, Renewables and Hydrogen (dated 8 January 2021) and sections 90 and 90AB of the Electricity Act, I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2021, the notified prices are the applicable prices set out in the attached Tariff Schedule.

As required by section 90AB(4) of the Electricity Act, the notified prices are exclusive of the goods and services tax ('GST') payable under the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) (the GST Act).

Dated this DD day of MMMM 2021.

**Flavio Menezes, Chair**
**Queensland Competition Authority**

1

**TARIFF SCHEDULE**

**Part 1 — Application**

***A) APPLICATION OF THIS SCHEDULE – GENERAL***

This Tariff Schedule applies to all Standard Contract Customers in Queensland other than those in the Energex distribution area.

Definitions of customers and their types are those set out in the *Electricity Act 1994 (Queensland)* (the Electricity Act) and the *National Energy Retail Law (Queensland)* (the NERL (Qld)). Unless otherwise defined, the terminology used in this Tariff Schedule is intended to be consistent with the energy laws.

***B) APPLICATION OF TARIFFS***

**General**
Any reference to a tariff is a reference to a retail tariff in the Tariff Schedule unless otherwise explicitly stated in the Tariff Schedule.

Distribution entities may have specific eligibility criteria in addition to retail tariff eligibility requirements set out in the Tariff Schedule, e.g. the types of loads and how they are connected to interruptible supply tariffs. Retailers will advise customers of any applicable distribution entity requirements upon tariff assignment or customer request. However, retailers must not pass through to customers the default network tariff assignment criteria.

Additional customer descriptions:

- A *Connection Asset Customer (CAC)* is a large business customer whose installed capacity generally exceeds 1000 kVA and is connected to the distribution network at a minimum nominal voltage of 11 kV, but not exceeding a nominal voltage of 66 kV as classified by the distribution entity.
- An *Individually Calculated Customer (ICC)* is a large business customer whose installed capacity generally exceeds 10 MVA and is connected to the distribution network at a minimum nominal voltage of 33 kV, but not exceeding a nominal voltage of 132 kV as classified by the distribution entity. A customer taking supply at these voltages, but with installed capacity less than 10 MVA, may request to be classified as an ICC if it satisfies specific criteria set out in the distribution entity's approved Tariff Structure Statement.

CAC or ICC customers can only access tariffs where specifically stated in the tariff description.

*Emergency* is as defined in the *National Energy Retail Rules* as applied in Queensland.

The *QECMM (Queensland Electricity Connection and Metering Manual)* as required in the *Metrology Procedure: Part A, National Electricity Market*, or similar document setting out the minimum requirements for connection of supply to customer premises as intended by the QECMM.

*MI* means the unique identification number applicable to the point at which a premises is connected to a distribution entity's network. For premises connected to the National Electricity Market this is the National Metering Identifier (NMI), and for other premises is the unique identifier allocated by the distribution entity.

An *MI exclusive* tariff cannot be used in conjunction with any other continuous supply primary tariff at that MI. All large customer tariffs are MI exclusive tariffs unless otherwise stated.

A retailer must assign the applicable *default tariff* to a small customer in the event the small customer does not nominate a tariff when they become a Standard Contract Customer of the retailer except where any existing metering configuration at the MI is for a primary interruptible supply tariff, in which case the small customer must expressly nominate a suitable primary tariff. Such assignment does not alter a small customer's ability to access other tariffs in the event the small customer requests assignment to another tariff.

The default tariff is:

- For residential customers–Tariff 11
- For small business customers–Tariff 20.

A *primary* tariff is the tariff that reflects the principal purpose of use of electricity at the premises or the majority of the load, and is capable of existing by itself against a MI.

Small business customers can access primary residential tariffs providing the nature of all use on the tariff is consistent with the tariff requirements (refer below for *concessional application* of primary residential tariffs), and is in conjunction with a primary business tariff (Tariff 20, 20A, 22A, 22B, 24, 24A, 24B, 34, 41, 62A, 65A or 66A) at the same MI.

Primary residential tariffs are also applicable to electricity used in separately metered common sections of residential premises consisting of more than one living unit, but cannot be used in conjunction with another primary residential tariff at the same MI.

A *secondary* tariff is any tariff that is not a primary tariff, and can be accessed only when it is in conjunction with a primary tariff at the same MI.

A *seasonal* tariff is any tariff for which charges vary depending on the month the charge applies. Seasonal tariffs can also include time-of-use based charges.

A *time-of-use* tariff is any tariff for which charges vary depending on the time of day.

Any reference in this Tariff Schedule to a time is a reference to Australian Eastern Standard Time.

*Weekdays* mean Monday to Friday including public holidays.

*Summer* is the months of December to February inclusive.

A *daily supply charge* is a fixed amount charged to cover the costs of maintaining electricity supply to a premises, including the costs associated with the provision of equipment (excluding metering and associated services) and general administration. Retailers may use different terms for this charge, for example: Service Charge, Service Fee, Service to Property Charge etc.

*A connection charge* reflects the value of the customer's dedicated connection assets and whether these assets were paid for upfront by the customer. The number of connection units allocated to an MI is as advised by the distribution entity.

*Demand* is the average rate of use of electricity over a 30-minute period as recorded in kilowatts (kW) on the associated metering, or as recorded or calculated in kilovolt-amperes (kVA) using data recorded on the associated metering.

No adjustment to import demand is made for export to the distribution network.

*Maximum demand* is highest demand during the charging period of the particular tariff as identified by the tariff description. Unless otherwise stated, the maximum demand is the value on which demand charges are based.

For large customer tariffs in Part 2 listing charge parameter options in both kW and kVA, the applicable charging parameter is to be kVA except for:

- MI with type 6 metering – kW;
- MI where type 6 metering is replaced with type 1 to 4 metering due to fault, age, distributor initiated customer reclassification, or other action not initiated by the customer – kW or kVA at the customer's choice until the first anniversary of the type 6 meter replacement, and kVA from that time;
- MI with type 1 to 4 metering and the tariff assigned to that MI changes from an obsolete tariff to a standard tariff – kW or kVA at the customer's choice until the first anniversary of the tariff change, and kVA from that time.

Once a retailer applies the kVA demand charging parameter to an MI, a kW demand charging parameter can no longer be applied to the MI unless otherwise permitted by energy law.

A *demand threshold* is the demand value below which demand charges for a tariff do not apply for billing purposes. Where a demand threshold applies, the chargeable demand is the greater of the maximum demand less the demand threshold, or zero.

*Authorised demand* is the maximum demand permitted to be imported from, or exported to the network, and is specific to each MI. The value is generally established by agreement between the customer and distribution entity.

*Excess demand* for the billing period is the greater of the maximum demand outside the peak demand window minus the maximum demand during the peak demand window, or zero.

*Capacity* is a demand-based measure of the network supply capability reserved for a customer. Unless otherwise stated, the capacity charge is the greater of the authorised demand, or actual maximum demand.

*Bus* customers are those taking supply via direct connection to the distribution entity's zone substation or similar as advised by the distribution entity.

*Line* customers are those taking supply via direct connection to the distribution entity's high voltage electrical wires, cabling, or similar as advised by the distribution entity.

**Continuous supply standard tariffs**

***Tariff 11***

This tariff shall not apply in conjunction with any other primary residential tariff.

***Tariff 20***

This tariff shall not apply in conjunction with any other primary business tariff.

***Tariffs 20A and 22B***

The applicable daily supply charge for each customer's bill is determined by multiplying the customer's total average daily usage for all meter registers at the MI for the billing period by the number of days in the calendar year. Average daily usage is calculated on a pro rating basis having regard to the number of days in the billing period that supply was connected as expressly allowed or permitted by energy law. The applicable daily supply charge for the billing period is that which corresponds with the applicable annual usage Bands:

- Band 1 – up to 20,000 kWh/y
- Band 2 – 20,000 up to 40,000 kWh/y
- Band 3 – 40,000 up to 60,000 kWh/y
- Band 4 – 60,000 up to 80,000 kWh/y
- Band 5 – 80,000 kWh/y and above

***Tariffs 14A and 24A***

Customers choosing these tariffs should be aware that the underlying network tariffs may be subject to larger annual price changes compared to other network tariffs as distribution entities move them toward the network prices that underpin Tariffs 14B and 24B respectively. It is likely the network tariffs will then be extinguished. This process will likely impact future prices and access to Tariffs 14A and 24A.

***Tariff 43***

This tariff is only available to large business customers with basic metering (type 6) where that metering is not capable of measuring electricity usage under an alternative applicable standard tariff.

**Interruptible supply standard tariffs**

***General***

The retailer will arrange the provision of load control equipment on a similar basis to provision of the required revenue metering.

Where a customer's aggregate load that is connected to an interruptible supply tariff exceeds 20 amperes per phase, additional load control equipment must be installed in accordance with the QECMM. Such equipment must be installed at the customer's expense.

***Availability of supply***

***Tariff 31***

Supply will be available for a minimum of 8 hours per day for customers connected to the Ergon Energy network, and 5 hours per day for customers connected to the Essential Energy network, but may be reduced in an emergency. Times when supply is available is subject to variation at the absolute discretion of the distribution entity. In general, this supply will be between the hours of 10.00 pm and 7.00 am.

***Tariff 33***

Supply will be available for a minimum of 18 hours per day for customers connected to the Ergon Energy network, and 10 hours per day for customers connected to the Essential Energy network, but may be reduced in an emergency. Times when supply is available is subject to variation at the absolute discretion of the distribution entity.

***Tariffs 34, 60A and 60B***

These tariffs are not available to customers connected to the Essential Energy network within Queensland.

Supply will be available for a minimum of 18 hours per day for customers connected to the Ergon Energy network, but may be reduced in an emergency. Times when supply is available is subject to variation at the absolute discretion of the distribution entity.

***Changes to connected load***

Customers must notify their retailer of any change of more than 30 kW to the load connected to its interruptible supply tariff, including if the change is a reduction.

***Other access requirements***
***Tariff 33***
This tariff shall not apply in conjunction with Tariff 24.

Existing residential customers accessing this tariff as a primary tariff must transition to an applicable standard residential primary tariff by 1 July 2022.

***Tariffs 34 and 60A***
These tariffs shall not apply in conjunction with any other tariff.

***Tariffs 60A and 60B***
These tariffs are only available in areas where the distribution entity's standard load control signalling operates. Access to the tariffs may be subject to a network impact assessment by the distribution entity supporting customer access.

***Electrical equipment connected to secondary interruptible supply tariffs***
These tariffs are applicable where there is no provision to supply electrical equipment, or any specified part of electrical equipment, that is connected to a secondary interruptible supply tariff via another tariff (e.g. via a change-over switch to a continuous supply tariff), and electricity supply is:

(a) connected to electric vehicle supply equipment (residential customers only), or pool filtration or sanitation systems via a general purpose socket-outlet specifically labelled to indicate that it is connected to an interruptible supply tariff; or

(b) permanently connected to electric or heat pump storage water heaters, boost elements of solar water heaters, electric vehicle supply equipment, pool filtration or sanitation systems, pumping or irrigation equipment, battery energy storage systems, solar power systems, or other appliances (e.g. washing machines or dishwashers).

Where a part (e.g. a one-shot booster or circulating pump for a solar water heater) of electrical equipment connected to a secondary interruptible supply tariff is connected to another tariff, the part must be metered under and charged at the primary tariff of the premises concerned, or if more than one primary tariff exists, the tariff applicable to general power usage at the premises.

**Unmetered supply standard tariffs**
***Tariff 71***
*Street lighting customers* as defined in Queensland legislative instruments, are State or local government agencies for street lighting loads.

Street lights are deemed to illuminate the following types of roads:

- *Local government* controlled roads comprising land that is:
  (a) dedicated to public use as a road; or

  (b) developed for (or has as one of its main uses) the driving or riding of motor vehicles and is open to, or used by, the public; or

  (c) a footpath or bicycle path; or

  (d) a bridge, culvert, ford, tunnel or viaduct,

  and excludes State-controlled roads and public thoroughfare easements; and

- *State-controlled roads* declared as such under the *Transport Infrastructure Act 1994* (Qld).

All usage will be determined in accordance with the metrology procedure.

***Tariff 91***
This tariff is only available to customers with small loads other than street lights as set out in the distribution entity's Approved Unmetered Supply Devices list (or equivalent document), and applies where:

(a) the load pattern is predictable;

(b) for the purposes of settlements, the load pattern (including load and on/off time) can be reasonably calculated by a relevant method set out in the metrology procedure; and

(c) it would not be cost effective to meter the connection point taking into account:
   (i) the small magnitude of the load;

   (ii) the connection arrangements; and

   (iii) the geographical and physical location.

Charges are based on usage determined by the retailer.

Charges for installation, maintenance and removal of supply to an unmetered installation may apply in addition to the charge for electricity supplied. These charges are not regulated.

**Individually Calculated Customers**
As an alternative to Tariff 53 set out in Part 2 of this Schedule, Standard Contract Customers classed as ICC can choose to be supplied and billed by their retailer under the ICC site-specific tariff set out in Part 2 of this Schedule.

**Obsolete tariffs**
***Limited-access obsolete tariffs***
Small business customers can switch once to a *limited-access obsolete* tariff only if they have accessed the corresponding *discontinued* tariff as set out below at any time between 1 July 2017 and 30 June 2020:

| Discontinued Tariff | Limited-access obsolete tariff |
|---|---|
| Tariff 62 | Tariff 62A |
| Tariff 65 | Tariff 65A |
| Tariff 66 | Tariff 66A |

Any subsequent tariff change by the customer must be to an applicable standard tariff, and the customer can no longer access a limited-access obsolete tariff.

***Obsolete tariffs***
*Obsolete* tariffs can only be accessed by customers who are on the tariff at the date it becomes obsolete and continuously take supply under it.

The *scheduled phase-out date* is the date an obsolete tariff will be discontinued.

***Tariff 47***
Supply under this tariff will be at a standard high voltage, the level of which shall be prescribed by the distribution entity. Credits for high voltage supply are not applicable to this tariff.

***Tariff 65A***
The *daily pricing period* is a fixed 12-hour period as agreed between the retailer and the customer from the range 7.00am to 7.00pm; 7.30am to 7.30pm; or 8.00am to 8.00pm Monday to Sunday inclusive.

No alteration to the agreed daily pricing period is permitted until a period of twelve months has elapsed from the previous selection.

***Tariff 66A***

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The fixed charge is determined by the larger of the connected motor capacity used for irrigation pumping, or 7.5 kW.

Any customer taking supply under this tariff who requests a temporary disconnection will not be reconnected unless an amount equivalent to the fixed charge that would have otherwise applied corresponding to the period of disconnection, has been paid.

**Tariff changes**

***Discontinued or redesignated tariffs***

Customers supplied under tariffs which have been discontinued or redesignated (whether by number, letter or name) on the date of the tariff being discontinued or redesignated, and whom have not notified their retailer of their preferred applicable standard tariff, will be transferred to an applicable standard or limited-access obsolete tariff at the discretion of the retailer upon the tariff being discontinued or redesignated.

***Seasonal time-of-use tariffs***

Customers on seasonal time-of-use tariffs cannot change to another tariff less than one year from the application of the tariff to the customer's account unless expressly allowed or permitted by energy law.

**Prorating of charges on bills**

Where appropriate, charges on bills will be calculated on a pro rata basis having regard to the number of days in the billing cycle that supply was connected as expressly allowed or permitted by energy law. Retailers can advise customers of which charges on their bills are subject to prorating, and the methodology used.

**Supply voltage**

Tariffs can only be accessed by customers taking supply at *low voltage* as set out in the *Electricity Regulation 2006* unless specifically stated in the tariff description, or otherwise agreed with the retailer.

Until 30 June 2022, where supply is given and metered at high voltage and the tariff applied is not a designated high voltage tariff, after billing the energy and demand components of the tariff a credit will be allowed of:

- 5 percent of the calculated tariff charge where supply is given at voltages of 11kV to 33kV; or
- 8 percent of the calculated tariff charge where supply is given at voltages of 66kV and above,

provided that the calculated tariff charge after application of the credit is not less than the Minimum Payment or other minimum charge calculated by applying the provisions of the applied tariff.

**Metering**

***General***

*Revenue metering* is metering used for billing purposes. Appropriate revenue metering must be in place for each tariff at a MI, unless otherwise permitted by energy law. Meter wiring and equipment to house meters is the customer's responsibility and must be installed and maintained at the customer's expense.

All data used for billing purposes will be determined in accordance with the metrology procedure unless otherwise permitted by energy law. The use of data substitutes or estimates is permissible, where in accordance with energy law.

The *metrology procedure* is the metrology procedure as issued by the Australian Energy Market Operator, and as added to by the *Electricity Distribution Network Code (Queensland)*.

A *type 4A* meter is a type 4 advanced digital meter which has the remote communications functions disabled.

Charges for customer metering services regulated by the Australian Energy Regulator and levied by the distribution entity are not included in notified prices. These will be applied to customers with metering other than types 1 to 4, in addition to the applicable notified prices contained in this Tariff Schedule.

If a retailer has received an upfront payment for supply and installation of metering at an MI, while the metering remains installed the retailer shall not charge the customer the capital charge set out in Part 4 of this Schedule, unless:

- any replaced metering is type 5 or type 6; and
- replacement is completed on a customer initiated request; and
- the distribution entity as owner of the replaced meter continues to charge the retailer the capital charge for the replaced meter.

***Card-operated meter customers***

If a customer is an excluded customer (as defined in section 23 of the Electricity Act), the distribution entity may at its absolute discretion agree with the relevant local government authority on behalf of the customer, and the customer's retailer, that the electricity used by the customer is to be measured and charged by means of a card-operated meter.

If, immediately prior to 1 July 2007, electricity being used by a customer at premises is being measured and charged by means of a card-operated meter, the electricity used at the premises may continue to be measured or charged by means of a card-operated meter.

Residential customers with card-operated meters can access Tariff 11 as their primary tariff, and Tariffs 31 and 33 as secondary tariffs.

Small business customers with card-operated meters can access Tariff 20 as their primary tariff.

Charges will be those as set out in Part 2 for the particular tariff.

**Other retail fees and charges**

A retailer may charge its Standard Contract Customers the following:

(a) if, at a customer's request, the retailer provides historical billing data which is more than two years old:
   – a maximum of **$30**

(b) retailer's administration fee for a dishonoured payment:
   – a maximum of **$15**

(c) financial institution fee for a dishonoured payment:
   – a maximum of **the fee incurred by the retailer**

(d) in addition to the applicable tariff, an additional amount in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not that additional amount is calculated on the basis of the customer's electricity usage), but only if:
   (i) the customer voluntarily participates in such program or scheme;
   (ii) the additional amount is payable under the program or scheme; and

(iii) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

In the absence of a notified price, a retailer may charge a customer for the provision of distribution entity alternative control services at the prices regulated by the Australian Energy Regulator, or as otherwise modified by energy law, for those services on a cost pass through basis. These charges may be applied to a customer's bill in addition to the notified prices contained in this Tariff Schedule.

**Concessional application**
Tariff 11, Tariff 12A and Tariff 14 are also available to customers where they satisfy the additional criteria set out in any one of **1**, **2** or **3**, below:

**1.** Separately metered installations where all electricity used is in connection with the provision of a Meals-on-Wheels service, or for the preparation and serving of meals to the needy and for no other purpose.

**2.** Residential institutions:
(a) where the total installation, or that part supplied and separately metered, must be domestic residential (i.e. it must include the electricity usage of the cooking, eating, sleeping and bathing areas which are associated with the residential usage). Medical facilities, e.g. an infirmary, which are part of the complex may be included; and

(b) that are:
(i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and

(ii) a non-profit organisation that:
A. imposes no scheduled charge on the residents for the services or accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or

B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged Care Act 1997* or the *National Health Act 1953*.

**3.** Organisations providing support and crisis accommodation which:
(a) have a service agreement for homelessness funding administered by the State; and

(b) are a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible.

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**Part 2—Standard tariffs**

These tariffs are applicable subject to the matters set out in Part 1.

**Small customer tariffs**

| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 11 | Residential flat-rate primary tariff | Usage | 19.782 | c/kWh |
| | | Daily supply charge | 88.392 | c |
| 12A | Residential seasonal time-of-use primary tariff | Usage – Peak (Summer 3pm-9:30pm) | 51.260 | c/kWh |
| | | Usage – All other times | 16.461 | c/kWh |
| | | Daily supply charge | 69.967 | c |
| 12B | Residential time-of-use primary tariff | Usage: | | |
| | | Peak (4pm – 9pm) | 26.241 | c/kWh |
| | | Day (9am – 4pm) | 14.664 | c/kWh |
| | | Night (all other times) | 16.398 | c/kWh |
| | | Daily supply charge | 88.392 | c |
| 14 | Residential seasonal time-of-use monthly demand primary tariff. | Chargeable demand – Peak | 48.769 | $/kW |
| | *Peak daily demand* is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm during Summer. | Chargeable Demand – Off peak | 7.004 | $/kW |
| | | Usage | 13.079 | c/kWh |
| | *Off-peak daily demand* is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm during all other times. | Daily supply charge | 42.958 | c |
| | *Peak chargeable demand* is the average of the four highest peak daily demands in the month. | | | |
| | *Off-peak chargeable demand* is the greater of the average of the four highest off-peak daily demands in the month, or 3kW. | | | |
| 14A | Residential time-of-use monthly demand primary tariff. | Demand: | | |
| | | Peak (4pm – 9pm) | 2.563 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 16.807 | c/kWh |
| | | Daily supply charge | 87.252 | c |

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| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 14B | Residential time-of-use monthly demand primary tariff. | Demand: | | |
| | | Peak (4pm – 9pm) | 7.320 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 14.045 | c/kWh |
| | | Daily supply charge | 87.252 | c |
| 20 | Small business flat-rate primary tariff. | Usage | 22.551 | c/kWh |
| | | Daily supply charge | 121.032 | c |
| 20A | Small business inclining-band primary tariff. | Usage | 22.551 | c/kWh |
| | | Daily supply charge: | | |
| | | Band 1 | 121.032 | c |
| | | Band 2 | 150.351 | c |
| | | Band 3 | 179.773 | c |
| | | Band 4 | 209.196 | c |
| | | Band 5 | 238.618 | c |
| 22A | Small business seasonal time-of-use primary tariff. | Usage – Peak (Summer 10am–8pm weekdays) | 54.463 | c/kWh |
| | | Usage – All other times | 20.760 | c/kWh |
| | | Daily supply charge | 110.206 | c |
| 22B | Small business time-of-use inclining-band primary tariff. | Usage: | | |
| | | Peak (4pm – 9pm weekdays) | 30.778 | c/kWh |
| | | Day (9am – 4pm) | 18.677 | c/kWh |
| | | Night (all other times) | 21.657 | c/kWh |
| | | Daily supply charge: | | |
| | | Band 1 | 121.032 | c |
| | | Band 2 | 150.351 | c |
| | | Band 3 | 179.773 | c |
| | | Band 4 | 209.196 | c |
| | | Band 5 | 238.618 | c |

| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 24 | Small business seasonal time-of-use monthly demand primary tariff.<br>*Peak daily demand* is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm during Summer.<br>*Off-peak daily demand* is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm during all other times.<br>*Peak chargeable demand* is the average of the four highest peak daily demands in the month.<br>*Off-peak chargeable demand* is the greater of the average of the four highest off-peak daily demands in the month, or 3kW. | Chargeable demand – Peak | 73.402 | $/kW |
| | | Chargeable Demand – Off peak | 7.376 | $/kW |
| | | Usage | 15.260 | c/kWh |
| | | Daily supply charge | 57.590 | c |
| 24A | Small business time-of-use monthly demand primary tariff. | Demand:<br>Peak (4pm – 9pm weekdays) | 2.402 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 21.172 | c/kWh |
| | | Daily supply charge | 119.789 | c |
| 24B | Small business time-of-use monthly demand primary tariff. | Demand:<br>Peak (4pm – 9pm weekdays) | 9.580 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 18.670 | c/kWh |
| | | Daily supply charge | 119.789 | c |
| 31 | Small customer flat-rate secondary tariff with interruptible supply. | Usage | 13.026 | c/kWh |
| 33 | Small customer flat-rate secondary tariff with interruptible supply. | Usage | 14.313 | c/kWh |
| 34 | Small business flat-rate primary tariff with interruptible supply. | Usage | 16.682 | c/kWh |
| | | Daily supply charge | 110.983 | c |
| 41 | Small business monthly demand primary tariff. | Demand | 18.350 | $/kW |
| | | Usage | 13.688 | c/kWh |
| | | Daily supply charge | 625.564 | c |

**Large customer tariffs**

| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 43 | Large business inclining-block primary tariff | Usage: | | |
| | | up to 97,000 kWh per year | 10. 702 | c/kWh |
| | | all remaining usage | 18.628 | c/kWh |
| | | Daily supply charge | 4048.684 | c |
| 44 | Large business monthly demand primary tariff | Chargeable demand; or | 26.050 | $/kW |
| | Demand threshold 30 kW / 35 kVA. | Chargeable demand | 23.444 | $/kVA |
| | | Usage | 10.860 | c/kWh |
| | | Daily supply charge | 4048.684 | c |
| 45 | Large business monthly demand primary tariff | Chargeable demand; or | 21.125 | $/kW |
| | Demand threshold 120 kW / 135 kVA. | Chargeable demand | 19.013 | $/kVA |
| | | Usage | 10.860 | c/kWh |
| | | Daily supply charge | 13132.311 | c |
| 46 | Large business monthly demand primary tariff | Chargeable demand; or | 17.320 | $/kW |
| | Demand threshold 400 kW / 450 kVA. | Chargeable demand | 15.587 | $/kVA |
| | | Usage | 10.860 | c/kWh |
| | | Daily supply charge | 34223.182 | c |
| 50 | Large business seasonal time-of-use monthly demand primary tariff. | Peak chargeable demand | 68.077 | $/kW |
| | Peak is Summer, being 10:00am to 8:00pm on Summer weekdays for determining chargeable demand, and all day each day for usage. | Off-peak chargeable demand | 10.551 | $/kW |
| | | Peak usage | 10.491 | c/kWh |
| | Off-peak is all times in non-summer months for determining chargeable demand and usage. | Off-peak usage | 12.852 | c/kWh |
| | Peak demand threshold 20 kW. | Daily supply charge | 3413.813 | c |
| | Off peak demand threshold 40 kW. | | | |
| 50A | Large business time-of-use monthly demand primary tariff. | Demand: | | |
| | | Peak (4pm – 9pm weekdays) | 13.582 | $/kVA |
| | | Excess | 2.717 | $/kVA |
| | | Usage | 11.290 | c/kWh |
| | | Daily supply charge | 15816.913 | c |

| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 51A | Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 66kV. | Demand | 3.196 | $/kVA |
| | | Capacity | 3.483 | $/kVA |
| | | Usage | 10.265 | c/kWh |
| | | Daily connection charge | 5.861 | $/unit |
| | | Daily supply charge | 25506.786 | c |
| 51B | Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 33kV. | Demand | 3.311 | $/kVA |
| | | Capacity | 4.243 | $/kVA |
| | | Usage | 10.265 | c/kWh |
| | | Daily connection charge | 5.861 | $/unit |
| | | Daily supply charge | 18976.186 | c |
| 51C | Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV bus. | Demand | 4.015 | $/kVA |
| | | Capacity | 4.884 | $/kVA |
| | | Usage | 10.265 | c/kWh |
| | | Daily connection charge | 5.861 | $/unit |
| | | Daily supply charge | 17844.986 | c |
| 51D | Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV line. | Demand | 8.098 | $/kVA |
| | | Capacity | 9.423 | $/kVA |
| | | Usage | 10.265 | c/kWh |
| | | Daily connection charge | 5.861 | $/unit |
| | | Daily supply charge | 17198.586 | c |
| 52A | Large business high-voltage seasonal time-of-use monthly demand primary tariff only for customers classified as CAC and supplied at 33 or 66kV.<br>Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays.<br>Chargeable capacity excludes all demands occurring during the chargeable demand periods. | Chargeable demand | 12.437 | $/kVA |
| | | Chargeable capacity | 5.992 | $/kVA |
| | | Usage – Summer | 9.847 | c/kWh |
| | | Usage – All other times | 10.193 | c/kWh |
| | | Daily connection charge | 5.861 | $/unit |
| | | Daily supply charge | 14532.186 | c |

| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 52B | Large business high-voltage seasonal time-of-use monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV bus.<br>Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays.<br>Chargeable capacity excludes all demands occurring during the chargeable demand periods. | Chargeable demand | 46.898 | $/kVA |
| | | Chargeable capacity | 4.248 | $/kVA |
| | | Usage – Summer | 9.847 | c/kWh |
| | | Usage – All other times | 10.193 | c/kWh |
| | | Daily connection charge | 5.861 | $/unit |
| | | Daily supply charge | 14532.186 | c |
| 52C | Large business high-voltage seasonal time-of-use monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV line.<br>Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays.<br>Chargeable capacity excludes all demands occurring during the chargeable demand periods. | Chargeable demand | 76.547 | $/kVA |
| | | Chargeable capacity | 7.735 | $/kVA |
| | | Usage – Summer | 9.847 | c/kWh |
| | | Usage – All other times | 10.193 | c/kWh |
| | | Daily connection charge | 5.861 | $/unit |
| | | Daily supply charge | 14532.186 | c |
| 53 | Large business high-voltage monthly primary tariff only for customers classified as ICC. | Demand | 3.196 | $/kVA |
| | | Capacity | 3.483 | $/kVA |
| | | Usage | 10.265 | c/kWh |
| | | Daily supply charge | 25322.071 | c |
| ICC site-specific tariff | Large business high-voltage monthly primary tariff only for customers classified as ICC, where:<br>• the AER approved site-specific network charges are passed-through to customers and<br>• non-network components are chargeable as defined in Part 2 of this Schedule. | AER approved site-specific network charges | Network charges | - |
| | | Demand | 0.182 | $/kVA |
| | | Capacity | 0.199 | $/kVA |
| | | Usage | 8.816 | c/kWh |
| | | Daily supply charge | 2488.271 | c |
| 60A | Large business flat-rate primary tariff with interruptible supply. | Usage | 18.459 | c/kWh |
| | | Daily supply charge | 4048.684 | c |
| 60B | Large business flat-rate secondary tariff with interruptible supply. | Usage | 18.459 | c/kWh |

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**Unmetered supply tariffs**

| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 71 | Business flat-rate primary tariff for street lighting. | Usage | 23.770 | c/kWh |
| 91 | Business flat-rate primary tariff. | Usage | 19.413 | c/kWh |

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**Part 3—Obsolete tariffs**

These tariffs are applicable subject to the matters set out in Part 1.

| Tariff | Description | Charge type | *Rate* | Unit |
|---|---|---|---|---|
| 47 | Obsolete large business high voltage monthly demand primary tariff. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022 | Chargeable demand | 27.864 | $/kW |
| | | Usage | 12.446 | c/kWh |
| | | Daily supply charge | 44689.726 | c |
| 48 | Obsolete large business high voltage monthly demand primary tariff only for customers classified as CAC or ICC. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022 | Chargeable demand | 28.822 | $/kW |
| | | Usage | 12.874 | c/kWh |
| | | Daily supply charge | 46712.140 | c |
| 62A | Limited-access obsolete small business time-of-use declining-block primary tariff. Scheduled phase-out date: To be confirmed | Usage – 7am to 9pm weekdays: | | |
| | | first 10,000 kWh/month | 52.963 | c/kWh |
| | | remaining | 44.313 | c/kWh |
| | | Usage – all other times | 16.744 | c/kWh |
| | | Daily supply charge | 103.470 | c |
| 65A | Limited-access obsolete small business time-of-use primary tariff. Scheduled phase-out date: To be confirmed | Usage – Peak (daily pricing period) | 41.488 | c/kWh |
| | | Usage – all other times | 21.473 | c/kWh |
| | | Daily supply charge | 103.270 | c |
| 66A | Limited-access obsolete small business fixed dual-rate demand primary tariff. Scheduled phase-out date: To be confirmed | Fixed charge (monthly) – first 7.5kW | 3.744 | $/kW |
| | | Fixed charge (monthly) – remaining kW | 11.303 | $/kW |
| | | Usage | 20.240 | c/kWh |
| | | Daily supply charge | 210.670 | c |

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**Part 4—Metering service charges**

These charges are applicable subject to the matters set out in Part 1.

**Large customer—type 1, 2, 3, 4 (advanced digital) meters**

| Description | Charge type | Rate | Unit |
|---|---|---|---|
| Standard asset customer (annual consumption 750MWh or less) | Daily metering charge | 196.975 | c |
| Standard asset customer (annual consumption greater than 750MWh) | Daily metering charge | 233.770 | c |
| Connection asset customer | Daily metering charge | 429.862 | c |
| Individually calculated customer | Daily metering charge | 439.848 | c |

**Small customer—type 1, 2, 3, 4 (advanced digital) meters**

| Description | Charge type | Rate | Unit |
|---|---|---|---|
| Primary tariff | Daily capital charge | 7.106 | c |
| | Daily non-capital charge | 3.330 | c |
| Secondary tariff* (per tariff) | Daily capital charge | 2.053 | c |
| | Daily non-capital charge | 0.988 | c |

* Where Tariff 33 is accessed as a primary tariff, primary tariff charges apply.

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*End of Tariff Schedule*

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