Queensland Competition Authority

Technical appendices

# Regulated retail electricity prices in regional Queensland 2022–23

**February 2022**

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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.

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- Appendix B: Stakeholder submissions and references
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- Appendix D: Cost pass-through approach
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# APPENDIX A: MINISTER'S DELEGATION

Queensland Government

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

Our Ref: MN07763-2021

1 William Street
Brisbane Queensland
GPO Box 2457 Brisbane
Queensland 4001 Australia
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16 DEC 2021

Professor Flavio Menezes
Chair
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001
By email: carola.hofmann@qca.org.au

Dear Professor ~~Menezes~~ Flavio

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 2022-23.

The Queensland Government is committed to delivering affordable electricity for households and businesses which is fundamental to driving economic recovery in regional Queensland, especially given the ongoing COVID-19 pandemic.

I note the State-wide rollout and integration of electric vehicles (EVs) into Queensland will be an area of key focus in the upcoming 10-year Energy Plan and the Zero Emissions Vehicle Strategy. Pricing, infrastructure, network impacts and access to EVs will be considered as part of these strategies.

Charging is set to introduce new load onto the system and EV users will make decisions that will impact the electricity network in new ways. Uptake of EVs is growing quickly and Queensland wants to encourage this uptake in a sustainable way that limits adverse impacts on the system.

There is much uncertainty around technology costs, consumer preferences and the ability to positively manage the impacts of EVs on the system. Electricity tariffs are being deployed worldwide seeking to encourage the shift of load from peak periods to those of low demand. In Queensland, with the impressive uptake of solar power systems at both household and utility scale, demand is now consistently low during daylight hours. Modelling by the Australian Energy Market Operator suggests that if left unchecked this may present challenges to the reliability of our electricity network over the medium term.

With the introduction of Tariff 12B from 1 January 2021, regional Queensland is setting the pace in encouraging greater use of our abundant renewable energy. This new 'solar-soaker' tariff flips the old way of thinking about electricity prices with the cheapest rate of just 16.13 cents per kilowatt-hour (c/kWh) being available from 9:00am to 4:00pm. I am advised Tariff 12B has a cheap daytime off-peak network component of 4.24 c/kWh, however the energy cost component is flat across all time periods and does not reflect actual underlying energy cost structures that vary across the day. While this tariff will be reviewed under this delegation in a standard manner, I will also look to a new time-of-use tariff with improved price signals and I intend to provide a separate delegation in early 2022.

The Department of Energy and Public Works (the department) is already working with the QCA and other stakeholders on a new direction for tariffs that would inform and reflect this new approach. Vehicle to grid capability is also expected to further change how EVs and batteries interact with the network with two-way flows of electricity becoming more common. These represent valuable consumer-owned sources of flexible demand and supply.

As part of the price determination process, I would greatly appreciate QCA considering how tariffs could be structured to better guide customer behaviour. This will be critical in encouraging the charging of EVs in periods of low network demand and high renewable energy generation. It is important to manage costs to customers and minimise the need for new electricity infrastructure to cope with the switch from petroleum fuels to electricity as Queensland's EV fleet grows. The QCA may include commentaries about the need for new retail tariffs with different structures to those currently available and also incentives for customers to respond to stronger pricing signals within tariffs. This advice will inform a separate delegation for new tariffs suitable for EV customers which I intend to issue to the QCA in early 2022.

The 10-year Energy Plan and the Zero Emissions Vehicle Strategy will assist in setting direction for key stakeholders through to 2030. The department will work closely with its electricity distributors to ensure the right mix of network tariffs are in place, building the platforms from which regulated retail tariffs will be developed for regional Queensland, and market driven retail products developed for South East Queensland (SEQ).

Realising a future that benefits all electricity users hinges on providing effective motivations, rewards and incentives for customers to move their electricity consumption. Solar-soaker and time-of-use tariffs are critical policy levers that can be used to support integrating a range of technologies like EVs, batteries, solar power and home energy management systems into Queensland's electricity network.

The enclosed delegation and terms of reference for 2022-23 are generally consistent with the approaches of previous delegations. The Queensland Government's Uniform Tariff Policy (UTP) as described in the delegation continues to capture the need for consideration of the Default Market Offer (DMO) by QCA in its determination. Given the DMO process is currently under review at the national level, I consider it appropriate that QCA conduct its usual process to determine all the associated costs that contribute to notified prices under the Queensland Government's long standing UTP. For small customers, this also means considering all costs and benefits associated with standing offers in SEQ.

Customers and stakeholders in regional Queensland have a long-standing preference for simplicity and choice with regards to electricity pricing. However, it is important that the Tariff Schedule reflect and provide appropriate and meaningful tariff options for customers, relative to their tariff class. As such, I ask QCA to consider reviewing the existing tariff offers with a view to rationalising them as it considers appropriate as part its 2022-23 price setting process.

QCA should consider if individual tariffs are meeting customer needs, and balance competing factors including the impact extinguishing a tariff would have on customers and their options, along with other matters QCA considers relevant. Consistent with application of UTP, this should be informed by the price structures commonly available in the deregulated SEQ electricity market and with a view to future needs for a variety of tariffs to be available as customer preferences, needs and technologies change.

I consider it necessary to retain at a minimum the existing flat-rate and controlled load tariffs for both residential and small business customers, and careful consideration should be given to retaining any tariffs compatible with the future wide-spread uptake of EVs and other technologies. In the event any tariff is to be extinguished, QCA should consider setting a suitable phase-out period that affords affected customers reasonable time to assess their remaining tariff options and to choose the most suitable ongoing standard tariff for their circumstances.

Another important policy consideration relates to the equitable pricing of metering services for customers. Consistent with the 2021-22 financial year, I ask QCA to consider and set the charges that apply to the provision of advanced digital metering services.

Public consultation has long formed a vital part of QCA's process for determining retail electricity prices. The terms of reference set out the consultation needs and requires QCA to publish its draft determination in February 2022 and its final determination by 31 May 2022.

To ensure regional customers continue to benefit from the electricity cost protection provided by UTP, and the benefits of owing our own assets, the department will be available to consult with QCA on the 2022-23 price determination and Tariff Schedule.

If you have any questions, [redacted] Executive Director, Energy Division, Department of Energy and Public Works, can be contacted on [redacted] or by email [redacted]

Yours sincerely

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

Encl: Section 90AA Delegation and Terms of Reference

DELEGATION TO QCA

DEPARTMENT OF ENERGY AND PUBLIC WORKS

***Electricity Act 1994***

**ELECTRICITY (MINISTERIAL) DELEGATION (NO. 1) 2021**
**to the Queensland Competition Authority (QCA)**

**Preliminary matters**

1. The preliminary matters form part of this delegation.

2. ***QCA*** means the Queensland Competition Authority established under the *Queensland Competition Authority Act 1997*.

3. Section 89A of the *Electricity Act 1994* (the Act) relevantly provides:
   ***price determination*** see section 90(1).
   ***pricing entity*** means—
   (a) the Minister; or
   (b) QCA, if the Minister delegates a function of the Minister under section 90(1) to QCA.

4. Section 90(1) of the Act provides:
   *The Minister must, for each tariff year, decide (a* ***price determination****) the prices, or the methodology for fixing the prices, that a retailer may charge its standard contract customers for all or any of the following—*
   *(a) customer retail services;*
   *(b) charges or fees relating to customer retail services;*
   *Examples—*
   *•charges or fees for late or dishonoured payments*
   *•credit card surcharges for payments for the services*
   *(c) other goods and services prescribed under a regulation.*

5. Section 90(5) provides:
   In making a price determination, the pricing entity—
   (a) must have regard to all of the following—
   (i) the actual costs of making, producing or supplying the goods or services;
   (ii) the effect of the price determination on competition in the Queensland retail electricity market;
   (iii) if QCA is the pricing entity—any matter the pricing entity is required by delegation to consider; and
   (b) may have regard to any other matter the pricing entity considers relevant.

6. Section 90AA(1) of the Act provides that the Minister may delegate to the QCA all or any of the Minister's functions under section 90(1) of the Act.

7. Section 90AA(2) of the Act provides that delegation to the QCA may state the terms of reference of the price determination.

8. Section 90AA(3) of the Act provides what the terms of reference may specify and how the terms of reference may apply.

9. The terms of reference provided for in sections 90AA(2) and (3) of the Act are contained in the Schedule to this delegation and comprise the matters under section 90(5)(a)(iii) of the Act that the QCA as the pricing entity is required by delegation to consider.

**Powers delegated**

10. Subject to the conditions of this delegation, I delegate all of the Minister's functions under section 90(1) of the Act to the QCA for the tariff year 1 July 2022 to 30 June 2023.

**Conditions of delegation**

11. The delegated functions of the Minister must only be exercised for the purpose of deciding the prices, or the methodology for fixing the prices that a retail entity may charge its Standard Contract Customers in Queensland, other than Standard Contract Customers in the Energex distribution area.

12. In exercising the delegated functions under section 89A, the QCA, as the pricing entity, must have regard to all of the matters set out in section 90(5)(a) of the Act, which includes the terms of reference in the Schedule to this delegation.

13. In exercising the delegated functions, the QCA must have regard to all relevant statutory provisions, whether referred to in this delegation or not.

**Revocation**

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

15. 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 2022–23 tariff year under section 90AB of the Act.

**Note to delegation**

16. Statutory references are to be construed as including all statutory provisions consolidating, amending or replacing the statute referred to and all regulations, rules, by-laws, local laws, proclamations, orders, prescribed forms and other authorities pursuant thereto.

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

**Signed:**

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

**Dated:** 16/12/2021

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 2022 to 30 June 2023.

***Policies, principles and other matters the QCA must consider when working out the notified prices and making the price determination (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 common price structures, regardless of their geographic location;

   (b) Reviewing existing available tariffs with a view to rationalising and extinguishing any tariffs no longer considered appropriate, including the introduction of suitable transition arrangements for any impacted customers, if required;

   (c) 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 generally treated as a pass-through and R (energy and retail cost) is determined by the QCA;

   (d) When determining the N components for each regulated retail tariff, where retained:

      (i) For residential and small business customer Tariffs 11 and 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 d(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;

(iv) For tariffs 62A, 65A, 66A and all large customer tariffs – 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';

(e) For all retained 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;

(f) Setting small customer advanced digital metering service charges at the Energex rate for standard Type 6 small customer metering services;

(g) 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;

(h) 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.

***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 2022–23 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 February 2022.

15. The QCA must publish the final price determination on regulated retail electricity tariffs for the 2022–23 tariff year and have the retail tariffs gazetted no later than 31 May 2022.

(SCHEDULE ENDS)

# APPENDIX B: STAKEHOLDER SUBMISSIONS AND REFERENCES

## Stakeholder submissions

We received 7 submissions on the interim consultation paper, available on our website.[1]

| **Stakeholder** | **Submission number** | **Date received** |
|---|---|---|
| Bundaberg Regional Irrigators Group (BRIG) | 1 | 19 January 2022 |
| Canegrowers | 2 | 19 January 2022 |
| Cotton Australia | 3 | 19 January 2022 |
| Ergon Energy and Energex Limited | 4 | 19 January 2022 |
| Ergon Energy Queensland (EER) | 5 | 19 January 2022 |
| Pioneer Valley Water Co-operative Ltd | 6 | 19 January 2022 |
| Queensland Farmers' Federation (QFF) | 7 | 19 January 2022 |

## References

ACIL Allen, *2020–21 regulated electricity price review: Updating retail costs*, final report, prepared for the QCA, May 2021.

—— *Estimated Energy Costs*, draft report, prepared for the QCA, February 2022.

Australian Competition and Consumer Commission (ACCC), *Inquiry into the National Electricity Market—November 2021 report*, November 2021.

Australian Energy Market Commission (AEMC), *Review of the regulatory framework for metering services*, directions paper, September 2021.

Australian Energy Market Operator (AEMO), *2021–22 AEMO Budget and Fees*, 2021.

—— *2021 Electricity Statement of Opportunities*, August 2021.

Australian Energy Regulator (AER), *Statement of Expectations of energy businesses: Protecting consumers and the market during COVID-19*, 9 April 2020.

—— *Default market offer prices: Options paper on the methodology to be adopted for the 2022–23 determination (and subsequent years)*, October 2021.

Energex, *Energex TSS Explanatory Notes 2020–2025*, December 2019.

—— *Energex Tariff Structure Statement 2020–2025*, June 2020 (erratum August 2020).

Ergon Energy Network and Energex, *Network Electric Vehicles Tactical Plan: Summary,* October 2020.

Queensland Competition Authority (QCA), *Supplementary review: Regulated retail electricity prices for 2020–21*, final determination, October 2020.

—— *Regulated retail electricity prices for 2021–22: Regional Queensland*, final determination, June 2021.

[1] We received one confidential submission from Ergon Energy Queensland, which is not published on our website.

—— *Regulated retail electricity prices for 2021–22: Regional Queensland, Technical appendices*, final determination, June 2021.

—— *SEQ retail electricity market monitoring 2020–21*, December 2021.

Queensland Government, *Queensland Budget 2021–22, Budget Strategy and Outlook*, Budget Paper no. 2, June 2021.

The University of Melbourne, *Electric Vehicle Uptake and Charging: A consumer-focused review*, April 2021.

# APPENDIX C: ENERGY COST APPROACH

This appendix provides further detail on why we consider ACIL Allen's (ACIL's) estimates are appropriate. It includes estimates for each of the three energy cost components (as noted in section 4.2.1). It covers some of the more complex methods and assessments used in estimating energy costs. ACIL's draft report, including the information we relied on to prepare this technical appendix, is available on our website.[2]

## Wholesale energy costs

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) to meet the electricity requirements (demand) of its customers. The NEM is a volatile market where spot prices are settled every 5 minutes and currently can range from –$1,000 to $15,100 per megawatt hour (MWh).[3]

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

- 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 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 approximate the timing and amount of electricity 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 how much electricity was consumed at a particular point in time.

However, when retailers acquire electricity from the NEM, they pay the Australian Energy Market Operator (AEMO) for electricity based on spot prices and electricity demand that both fluctuate every 5 minutes. To address this settlement issue for customers on accumulation meters, AEMO uses the regional NSLP to estimate daily average spot prices[5] derived from the NSLPs. Currently, most customers in Queensland are on accumulation meters.

[2] ACIL Allen, *Estimated Energy Costs*, draft report prepared for the QCA, February 2022.

[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, by purchasing financial derivatives, retailers can 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.

[5] This average price is estimated by taking the average of daily spot prices weighted by the electricity demand recorded under the NSLPs. In other words, spot prices with higher demand contribute more to the average price.

## Summary of analysis and findings

Consistent with previous years, ACIL 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 NEM. More specifically, this involves:

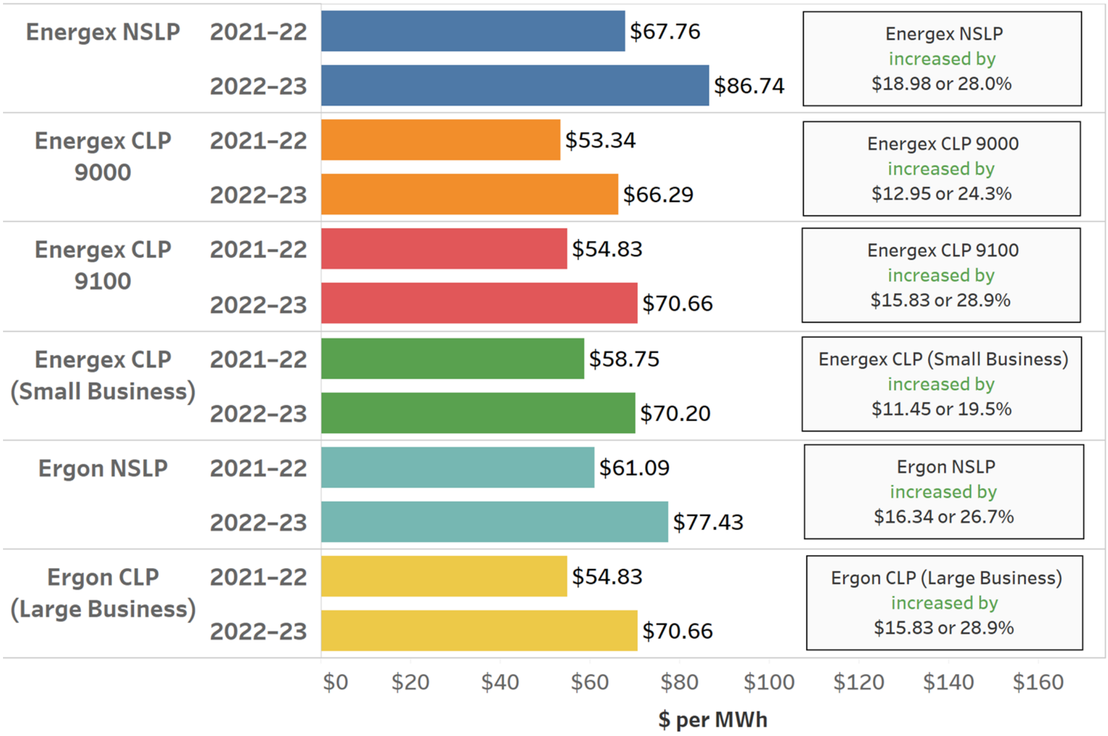
- simulating the expected spot prices that a retailer faces, considering temperature-related demand profiles, generation supply and costs, as well as power station availability; and then
- estimating wholesale energy costs for a retailer that hedges spot price risk through the purchase of ASX Energy futures[6].

Compared with last year's estimates, ACIL estimated an increase in wholesale energy costs for all customers in 2022–23, whose prices are settled on the NSLPs and CLPs identified above (Figure 1). This primarily reflects a substantial increase in the trade-weighted ASX contract prices[7] for base, peak and cap contracts.

The increase in ASX contract prices is likely driven by:

- a slowdown of renewable energy generators coming online (compared to recent years) and the continued unavailability of the Callide C power plant (unit 4)—both of which contribute to a tighter supply–demand balance in Queensland
- higher gas and coal prices
- uncertainties associated with the effects of 5-minute settlement.

**Figure 1 Wholesale energy costs by demand profiles (draft estimates)**




[6] 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/.

[7] Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for each of the four quarters of 2022–23.

## Demand considerations

To estimate wholesale energy costs, ACIL used its stochastic demand model to develop 51 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 2020–21, historical demand profiles from 2018–19 to 2020–21 and the expected uptake of rooftop solar photovoltaic (PV)
- AEMO's latest demand forecast for 2022–23, including energy forecasts of AEMO's central scenario and the seasonal peak demands with a 10% probability of exceedance (POE)[8], 50% POE and 90% POE.[9]

The weather-influenced system-wide hourly demand (i.e. the demand satisfied by scheduled and semi-scheduled generation[10]) 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's Market Management System (MMS) and Market Settlement and Transfer Solutions (MSATS). However, for the newly introduced tariffs with limited historical profiles (i.e. the load control tariffs for small and large business customers), ACIL used the relevant representative demand profiles that we recently developed using data from Energy Queensland.

The demand profile for the small business load control tariff was derived using Energy Queensland'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 the reports for our October 2020 price determination. [11]

### Demand profiles and historical energy cost levels

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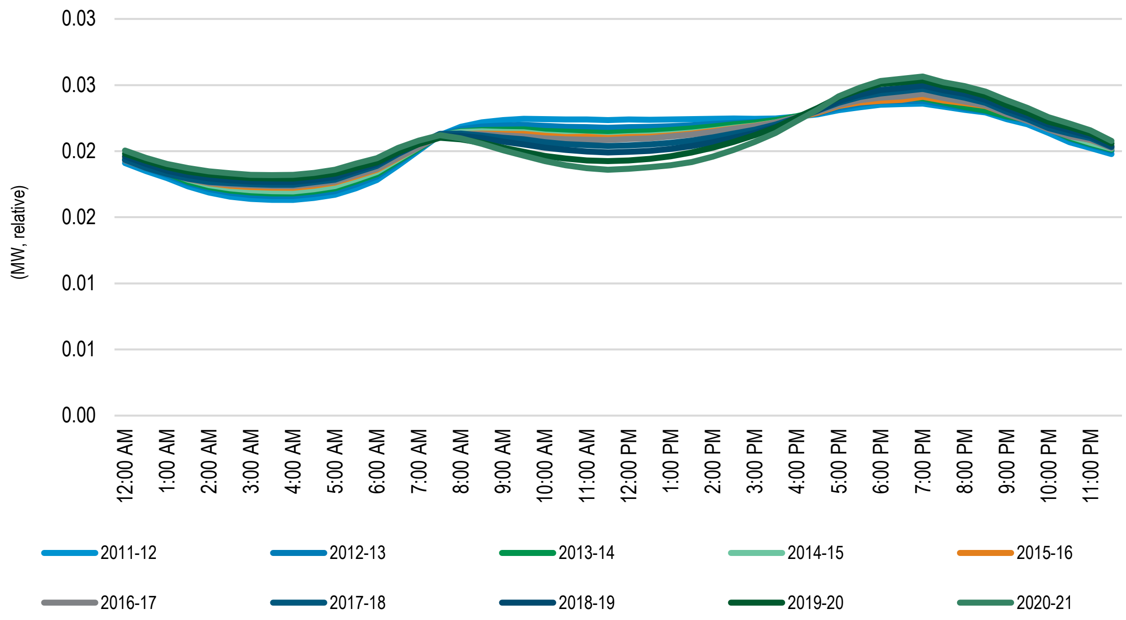
[8] POE is the probability of whether an electricity demand forecast will be met or exceeded. For example, a demand level with a 10% POE implies that there is a 10% probability of the forecast being met or exceeded. The 10% POE forecast is mathematically expected to be met or exceeded once in 10 years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

[9] AEMO, *2021 Electricity Statement of Opportunities*, August 2021.

[10] 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.

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

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

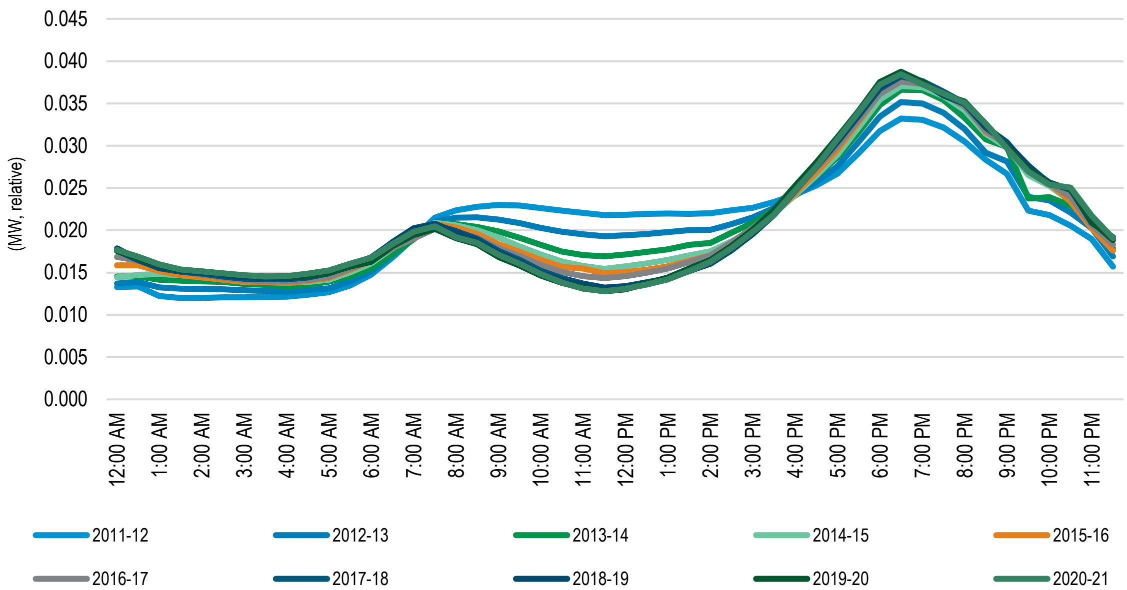



*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation of the load, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, draft report, prepared for the QCA, February 2022.*

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.

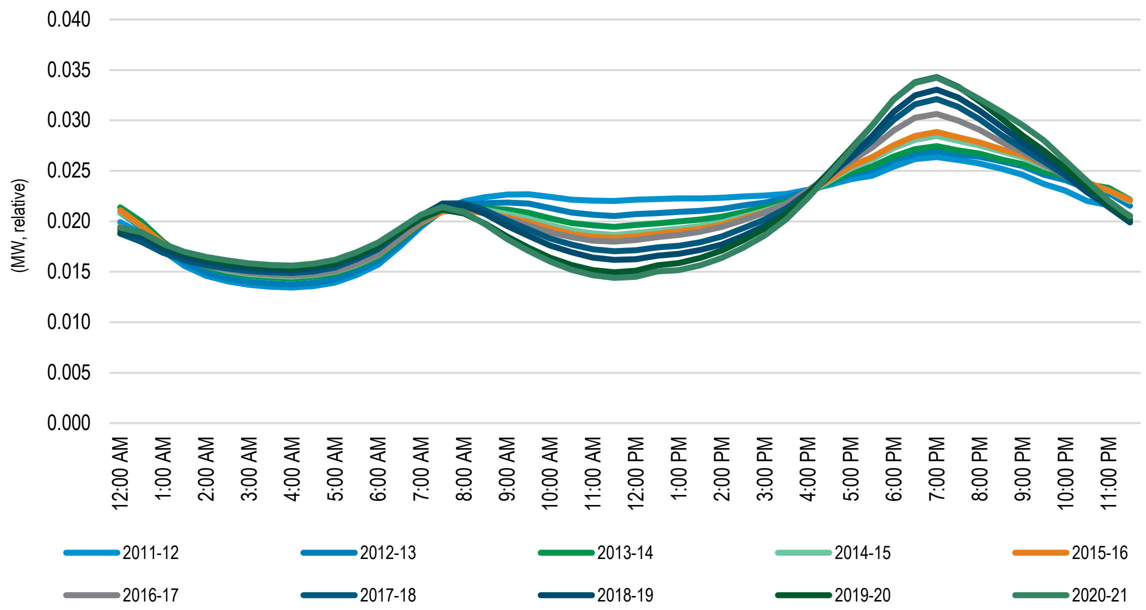
**Figure 3 Energex NSLP**




*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, draft report, prepared for the QCA, February 2022.*

**Figure 4 Ergon NSLP**

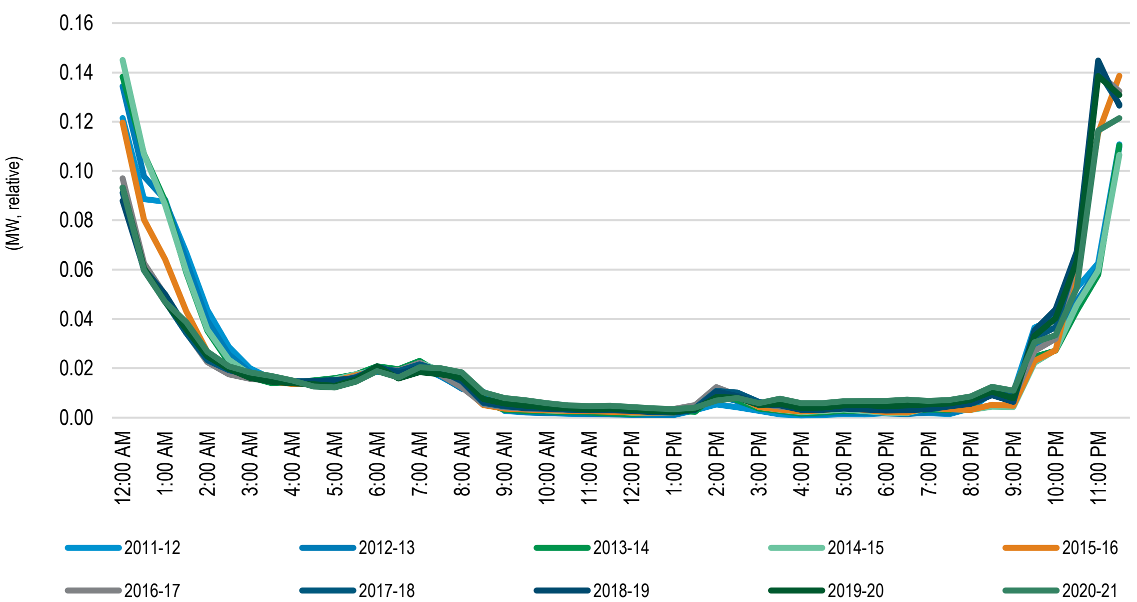



*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, draft report, prepared for the QCA, February 2022.*

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.

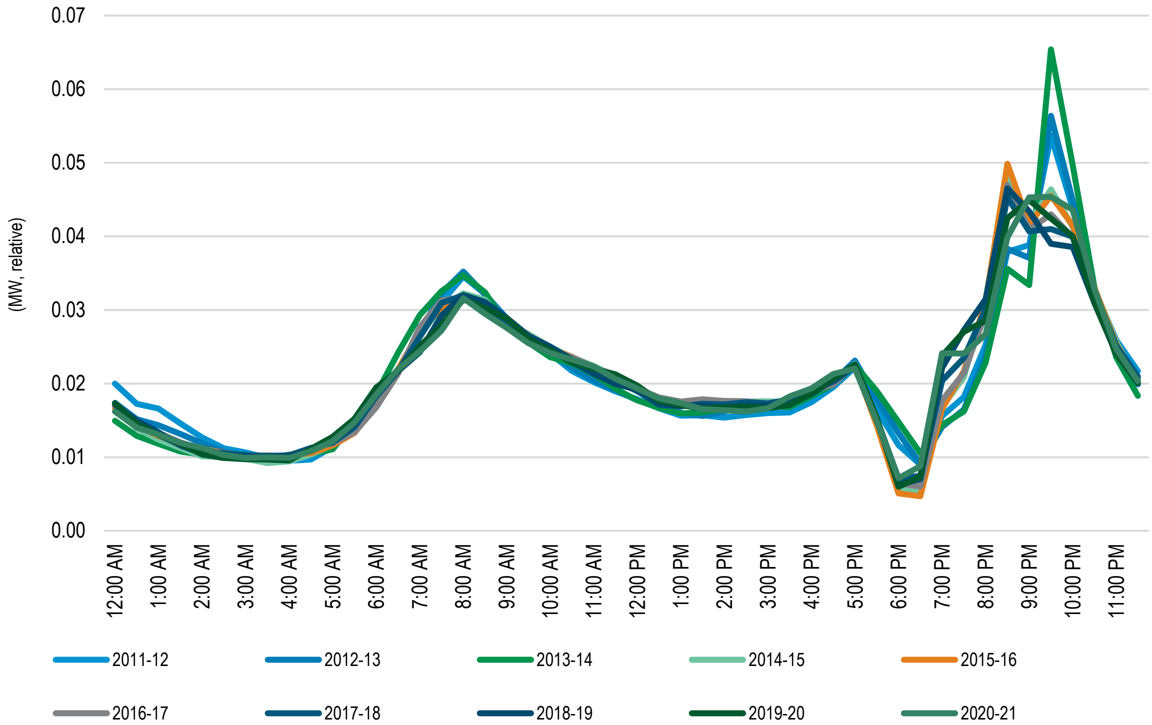
**Figure 5 Energex CLP 9000 (retail tariff 31)**




*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, draft report, prepared for the QCA, February 2022.*

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

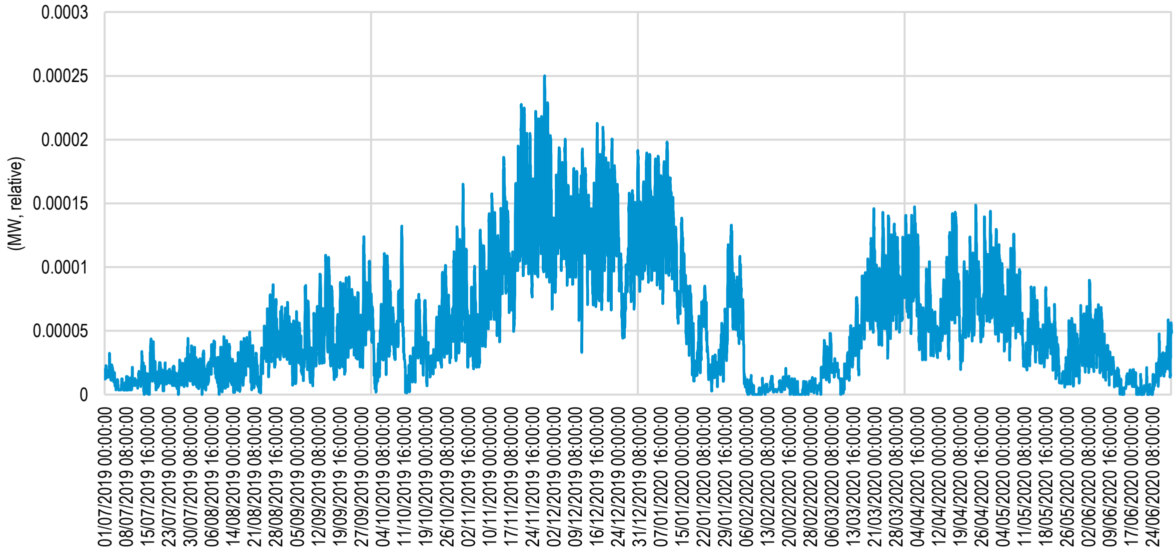



*Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.*

*Source: ACIL Allen, Estimated Energy Costs, draft report prepared for the QCA, February 2022.*

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).

**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's analysis of data from Energy Queensland's agricultural tariff trial.*

## Supply considerations

To simulate expected spot prices, ACIL has developed several datasets that reflect the supply dynamics within the NEM. These include:

- thermal power plant availability—ACIL used its stochastic outage model to develop 11 hourly power station availability simulations. The outage simulation is designed to reflect the probability of various planned and forced outages of generators and the effect they would have on spot prices
- renewable energy resource—using its renewable energy resource model, ACIL estimated a set of traces that reflects the availability and quality of renewable resources/generation (such as wind and solar) in different regions across the NEM by taking into account weather and geographical conditions.
- These traces are consistent with the weather conditions for the demand profiles from 2018–19 to 2020–21. 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
- generation information—ACIL maintains a reference case projection of the NEM, which incorporates generator-related data such as costs and technological characteristics of generators, contract cover and portfolio ownership structure. It updates the reference case each quarter in response to the latest supply changes announced in terms of new investments, retirements, fuel costs and generator availability.
- ACIL incorporates 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 deem these plants to be committed projects.
- ACIL's forecast of the generation supply and costs within the NEM also closely aligns with AEMO's latest Integrated System Plan (ISP) and Electricity Statement of Opportunities (ESOO).[12] To achieve this, ACIL would routinely compare its detailed assumptions with AEMO's ISP and ESOO findings, including the technical parameters of generators, fuel prices and interconnector expansions. Any deviation in assumptions was investigated, and AEMO's findings were adopted if the deviation could not be justified. However, to date, ACIL's assumptions were closely aligned with AEMO's findings.

## Spot price simulation

ACIL applied its proprietary electricity model (PowerMark) to generate 561 simulations of 8,760 hourly wholesale electricity spot prices for 2022–23. PowerMark dynamically simulates the behaviour of generators in the NEM by allowing each portfolio of generators to optimise its bids to maximise profit, considering the stochastic demand profiles, thermal power plant availability, renewable energy resource traces and generation information.

This dynamic bidding algorithm allows PowerMark to account for changes in generators' bidding behaviour that are caused by evolving market conditions, such as the recent influx of renewable generation and changes in underlying costs.

ACIL advised that its wholesale spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX futures) for 2022–23. More details are available in chapters 2 and 4 of ACIL's draft report.

[12] The ISP and ESOO contain extensive technical data that inform the decision-making of interested parties as they assess opportunities in the NEM.

## Hedged energy costs—hedging methodology and contract prices

To simulate the wholesale energy costs incurred by a retailer that hedges spot price risk, ACIL developed a hedging methodology based on the standard ASX energy base, peak and cap futures contracts.

ACIL used its hedge model to test a substantial number of strategies to derive a hedging strategy (and contract volume) with the lowest cost and variance, considering the latest simulated demand profiles, spot prices and trade-weighted contract prices. Specifically, ACIL evaluated multiple strategies by varying the mix of base, peak and cap contracts for each quarter and analysing the resulting distribution of wholesale energy costs for each strategy.

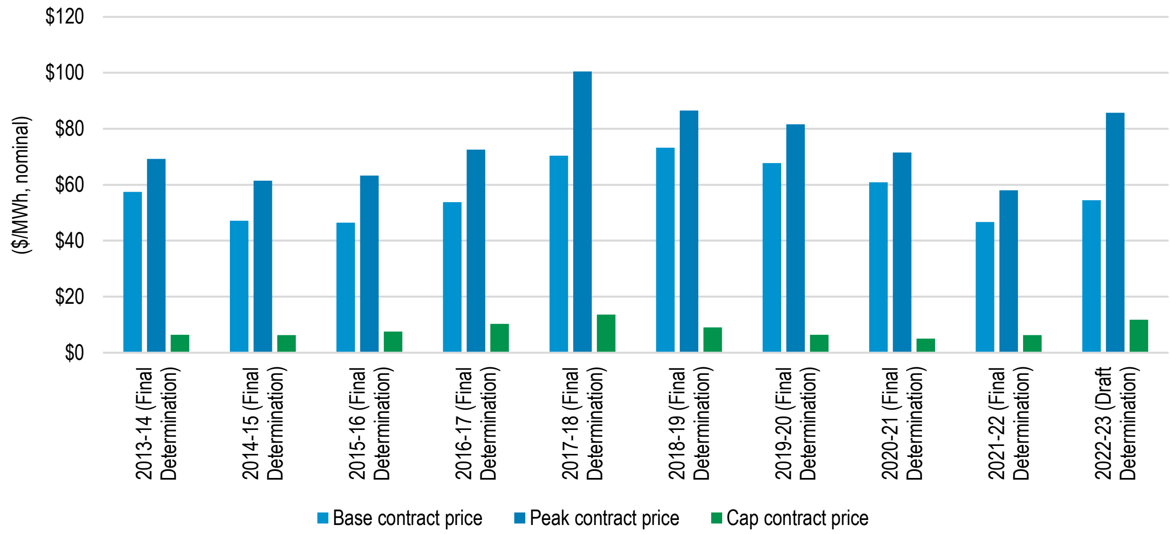
Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of quarterly base, peak and cap contracts for 2022–23. To calculate the trade-weighted contract prices, ACIL used the Queensland contract prices and volume of contracts traded until 21 January 2022 inclusive. Trading of ASX contracts tends to commence a number of years before the relevant financial year. For example, trading for 2022–23 ASX base contracts commenced as early as late 2018. This is a reflection of how market participants (such as retailers) purchase ASX contracts in advance to lock in their costs and manage spot price risk.

For the final determination, actual ASX Energy futures data until April 2022 will be used to estimate contract prices. More details on ACIL's approach are available in chapter 4 of its draft report.

As shown in Figure 8, compared to last year's prices, contract prices for 2022–23, on an annualised and trade-weighted basis, have to date:

- increased by about $7.30/MWh for base contracts
- increased by about $28.50/MWh for peak contracts
- increased by about $6.20/MWh for cap contracts.

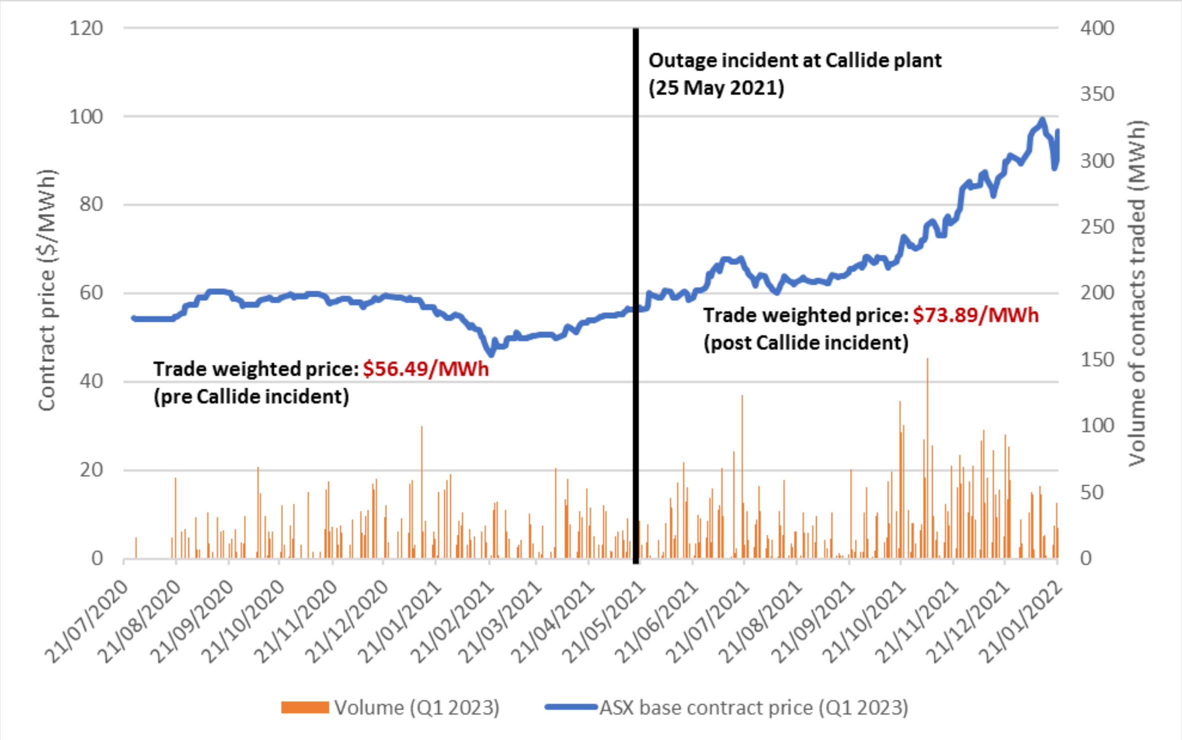
**Figure 8 Annualised quarterly electricity futures contract prices ($/MWh)**




*Source: ACIL Allen, Estimated Energy Costs, draft report, prepared for the QCA, February 2022.*

This reflects market participants expecting an increase in spot prices, likely due to a slowdown of renewable energy generators coming online (compared to recent years), the continued unavailability of the Callide C power plant (unit 4), a tighter supply–demand balance in Queensland, and higher gas and coal prices. Following the incident at Callide in May 2021, ASX base contract prices increased substantially as it became apparent that the unit would not return to service for quite some time (as demonstrated in Figure 9). Coal and gas prices also increased noticeably in recent months—further increasing the market's expectations of a prolonged increase in spot prices for 2022–23.

**Figure 9 Queensland ASX base contract 2022–23 (summer quarter—Q1 2023)**




*Source: ASX Energy and QCA analysis.*

Moreover, ASX cap contract prices have also increased substantially in 2022–23 compared to last year (Table 1). This likely reflects:

- market participants' expectations of higher spot price volatility and gas prices
- uncertainties faced by cap contract providers around the ability of their peaking plant[13] to cover price spikes in the NEM under 5-minute settlement.

Holding other things constant, an increase of $1/MWh in cap contract price can increase the wholesale energy cost estimate for the NSLP by around $3/MWh due to the 'peaky' shape of the NSLP.

**Table 1 Queensland trade-weighted ASX cap contract prices (2021–22 and 2022–23)**

| *Cap contract* | *2021–2022 ($/MWh)* | *2022–2023 ($/MWh)* | *Change (%)* |
|---|---|---|---|
| ***Q3*** | 2.18 | 5.89 | 170 |
| ***Q4*** | 5.73 | 9.33 | 63 |
| ***Q1*** | 13.99 | 25.57 | 83 |
| ***Q2*** | 3.30 | 6.61 | 100 |

*Source: ACIL Allen and ASX Energy.*

[13] Peaking plants, such as open-cycle gas turbine plants, usually have higher operating costs but very fast start-up and shut-down times compared with coal-fired generators. These plants also can change outputs rapidly.

ACIL applied the hedging methodology (together with the simulated spot prices) to derive 561 annual hedged energy costs for a given demand profile. The 95th percentile of the distribution of hedged costs was used as the final estimate of the wholesale energy costs.

### Our analysis—wholesale energy costs

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

We consider ACIL'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, this 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 publicly available.

For the newly introduced tariffs with limited 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 uptake of these new tariffs is not yet widespread among customers, there is insufficient data to refine the demand profiles developed previously.

In developing its forecasts of demand profiles and generation supply/costs, ACIL 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, and 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 note that ACIL's approach has generated a distribution of spot prices for 2022–23 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's spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX futures) for 2022–23. 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 tested a substantial number of strategies to derive a strategy with the lowest cost and variance, taking into account the latest simulated demand profiles, spot prices and contract prices. 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.

Further, ACIL's approach also reflects how retailers, in practice, would build up a portfolio of financial derivatives in advance to minimise volatility in contract prices. To manage spot price risk, retailers generally purchase ASX contracts over a period ahead of the relevant financial year—to lock in the price (i.e. contract price) for an amount of electricity that they would pay for in the future. Contract prices fluctuate due to the actual and anticipated changes in the supply–demand balance within the NEM and futures markets at a particular point in time.

Consequently, past contract prices—reflecting the market's expectations of future spot prices at an earlier time—may have a significant impact on the wholesale energy costs incurred by retailers over a period if the market's expectations change noticeably. This is because retailers would have locked in their future electricity prices in advance, based on the contract prices at that time.

To account for this effect, ACIL's approach has estimated trade-weighted contract prices by using all available trade data for a given product (i.e. back to the first trade recorded by ASX Energy) rather than pre-specifying a particular pattern in the build-up of a portfolio of financial derivatives.

To estimate wholesale energy costs, ACIL took the 95th percentile of the distribution of 561 annual hedged energy costs for a given demand profile. We consider this is a conservative estimate, given that the 95th estimate is at the upper end of ACIL's projected hedged cost outcomes, which is less likely to underestimate the wholesale energy costs that prudent retailers face in the NEM.

### Spot price forecasting

Ergon Energy Retail (EER) noted that spot price outcomes in 2021 (average spot price of $88.74) were higher than the $40/MWh to $70MWh that ACIL had forecast. It suggested that this discrepancy is primarily due to the unforeseeable outage at the Callide power station.[14]

We consider ACIL's methodology for estimating spot prices is reasonable. Accurate forecasting is challenging due to unforeseeable events, uncertainties and information constraints. Consequently, we would expect differences between forecast and actual outcomes. This is particularly relevant for spot prices, given the estimation of spot prices is also dependent on a number of forecasts—for instance, peak demand, weather, and plant availability.

If ACIL's methodology consistently over- or under-estimated spot prices, we would need to consider the drivers of such outcomes. However, this is not the case, as median spot price forecasts have been both higher and lower than the actual spot price outcomes in the past few years.

To address potential unforeseeable events, ACIL has:

- updated its analysis using the latest available data, including the peak demand and supply projections from AEMO, and market participants' formal announcements on generation availability/operation
- attempted to capture the additional potential volatility by undertaking a large number of simulations to account for variations in demand, thermal plant availability, renewable energy resource and spot price outcomes.

Further, our market hedging approach uses ASX contract data, which are forward-looking and reflect market participants' expectations of future spot prices. On this basis, we are satisfied ACIL's methodology addresses unforeseeable events to the greatest extent practical using the latest available information.

Regardless, the incidence of higher than anticipated spot price outcomes does not necessarily mean that a prudent retailer will face higher actual wholesale energy costs. This is because a prudent retailer will use a variety of hedging instruments to limit its exposure to volatility in the spot market. It is notable that within ACIL's hedged cost distribution, hedged costs towards the bottom of the distribution are generally associated with high spot price projections. This is likely due to the contracts-for-differences payments that

[14] EER, sub. 5, p. 9.

arise from trading in ASX contracts coupled with a relatively conservative hedging strategy. These payments would reduce the total cost of hedging.

### Incidence of negative spot prices

EER raised the topic of the increasing incidence of negative spot prices:

> There is a continued steep increase in the occurrences of negative spot price events in Queensland driven by the sustained uptake of rooftop solar in the Queensland as per the table below. This trend also correlates with the decline in black coal generation…
>
> During 2021, almost 6% of prices were below $0, compared to less than 1% in 2015, noting that in 2021, Ergon Energy Retail saw several half-hours of around -$1,000/MWh, while the lowest price in 2015 was around -$160/MWh.[15]

Consistent with EER's view, we consider that the continued uptake of rooftop solar PV and development of utility scale solar PV will likely increase the number of negative spot prices during daylight hours.

However, this phenomenon is not something new. In our previous determinations, there were occasions when the simulated spot prices were below their corresponding trade-weighted contract prices (that a retailer locks in). In this situation, retailers will be compensated for this negative price difference through ACIL's hedge model as costs that retailers incurred while pursuing a hedging strategy using financial derivatives.

In its latest analysis for 2022–23, ACIL estimated that the percentage of spot price outcomes less than or equal to zero ranged between 11 and 15 per cent (across 561 simulations), compared with 6 per cent in 2021. On this basis, we are satisfied that ACIL's methodology adequately addresses EER's concerns and captures the impacts of negative spot price outcomes during daylight hours.

### Availability of cap contracts

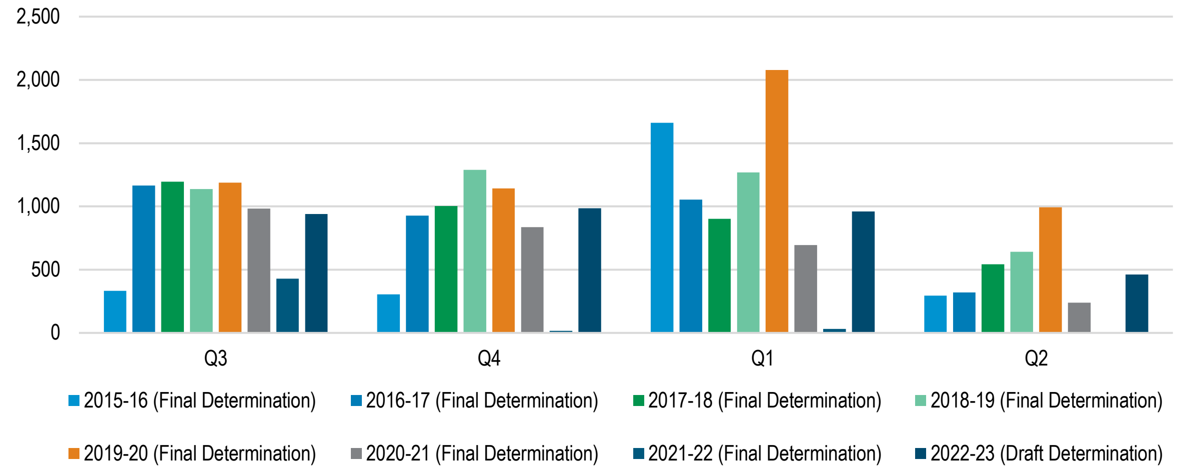
EER highlighted the low level of open interest[16] in cap contracts traded on ASX Energy:

> There is low interest in quarterly caps as published by the ASX in Queensland due to the inherent risk to sellers in offering this product when spot prices are volatile. While this does not include over the counter (OTC) interest, ACIL Allen should not assume that retailers can hedge the majority of their exposure in the visible and liquid cap market.[17]

However, except for 2021–22, the cumulative trade volume for cap contracts (to date for 2022–23) is on par with, or tracking close to, the trade volumes in previous years (Figure 10). In 2021–22, trade volume was lower due to the transition to 5-minute settlement. On this basis, we are satisfied that the markets for cap contracts are reasonably liquid.

[15] EER, sub. 5, p. 10.
[16] Open interest refers to the number of outstanding contracts that have not been closed (or are still active).
[17] EER, sub. 5, p. 10.

**Figure 10 Cumulative trade volumes—Queensland ASX quarterly cap contracts**




*Source: ACIL Allen and ASX Energy.*

### Conclusion

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

### 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 2022 and 2023.[18]

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 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 estimated that the LRET cost for 2022–23 will be $4.53/MWh for all retail tariffs—an increase of $0.24/MWh compared to the 2021–22 determination. This increase is due to higher LGC forward prices.

ACIL'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 2022–23. 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[19] provided by TFS Australia (an energy brokerage company). ACIL estimated the expected LGC prices by using the trade-weighted average (rather than the simple average) of LGC forward prices for 2022 and 2023. This approach assumes that retailers build up their LGC coverage over a period of time to meet their obligations under the LRET scheme.

ACIL estimated the expected LGC prices to be $26.54/MWh for 2022 and $22.36/MWh for 2023. LGC forward prices have increased since they were last estimated for the 2021–22 determination.

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 retailers will face to meet their obligations under the LRET scheme.

We consider this approach is appropriate, as it provides a reasonable representation of the LGC costs that retailers are likely to incur.

[18] *Renewable Energy (Electricity) Act 2000* (Cth), s. 40. For more information, see http://www.cleanenergyregulator.gov.au.

[19] 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.

#### Renewable power percentage

The RPP values dictate the number of LGCs that a retailer needs to purchase and surrender to the CER. To estimate the RPP, ACIL used the mandated LRET targets, the cumulative adjustment[20] (published by the CER) and its estimates of electricity acquisitions for 2022 and 2023.

The RPP value was estimated by dividing the LRET target by the electricity acquisitions of liable entities. The estimated RPPs are 18.54 per cent for both 2022 and 2023. We consider ACIL's approach to estimating the RPP to be appropriate for the draft determination, as it aligns with the CER's expectations and therefore reflects 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 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 2022–23 is estimated to be \$8.71/MWh for all retail tariffs—a decrease of \$2.81/MWh compared to the 2021–22 determination. This is driven by an expected decrease in the STPs and therefore the number of STCs that retailers are required to purchase.

We consider that ACIL'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 house processes. Such an approach is likely to produce a reliable estimate of the SRES costs to be incurred by retailers in 2022–23.

#### 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 (per MWh of electricity generated by eligible renewable systems).

We consider that ACIL'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

The STP values dictate the number of STCs that a retailer needs to purchase and surrender to the CER. To estimate the STPs for the draft determination, ACIL updated the CER's published non-binding STPs. These STPs were updated using the CER's STP modelling reports, in which the projected rates of uptake of small-scale renewable energy systems for 2022 and 2023 are similar to recently observed rates.[21] However, the

[20] This is a mechanism used by the CER to ensure that liable entities surrender only the number of LGCs needed to meet the legislated renewable energy targets.

[21] Clean Energy Regulator, *Small-scale technology percentage modelling reports*, CER website, Australian Government, accessed 31 January 2022.

decline in the deeming period for SRES would reduce the number of STCs that can be created for an eligible system, therefore resulting in lower STPs.[22] The estimated STPs are 22.4 per cent for 2022 and 21.15 per cent for 2023. For the final determination, updated STPs (published by the CER) would be used to estimate the SRES costs.

We consider this approach to be appropriate for the draft determination, as a more recent forecast captures 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 2022–23 DMO draft 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, the funding of Energy Consumers Australia, the 5-minute settlement compliance and distributed energy resource (DER) integration program. ACIL estimated the NEM fees using the budget and projected fees in AEMO's report.[23]

ACIL estimated that for 2022–23, NEM fees will be $0.67/MWh, an increase of $0.18/MWh, compared to the 2021–22 determination. This reflects an increase in costs related to operating the NEM, full retail contestability, the 5-minute settlement compliance and the DER integration program.

We consider ACIL'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 2022–23.

### 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 estimated the ancillary services charges using the region-specific average ancillary service payments[24] observed over the preceding 52 weeks. For 2022–23, ancillary services charges were estimated to be $1.26/MWh, an increase of $0.85/MWh, compared to the 2021–22 determination. This increase is driven by higher costs for FCAS in Queensland. Higher FCAS costs have occurred on days when outages related to

[22] The CER adopted the deeming approach as a more efficient method for determining the number of STCs that an eligible small-scale renewable system can create upfront without the administrative burden of measuring the output of each individual system. Under this approach, the number of STCs that can be created by an eligible system is calculated based on the system location, size, installation date and deeming period. Since the SRES is scheduled to end in 2030, the deeming period for eligible systems installed after 2021 would decrease by one year, every year until 2030. This will reduce the number of certificates that can be created for an eligible system.

[23] AEMO, *2021–22 AEMO Budget and Fees*, June 2021.

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

upgrades of the Queensland to New South Wales interconnector (QNI) required significantly increased local supply of FCAS.

We consider ACIL'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 (also known as AEMO and hedge prudential costs). ACIL estimated these prudential 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 were estimated to increase compared with last year, largely driven by higher contract prices and higher expected price volatility in the NEM. ACIL estimated the 2022–23 prudential costs to be $2.11/MWh for the Energex NSLP (and CLPs) and $1.73/MWh for the Ergon NSLP.

We consider that ACIL's approach to estimating prudential costs is appropriate, as it aligns 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 2022–23.

### 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.

When estimating the AEMO prudential costs, ACIL 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 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 estimated the 2022–23 AEMO prudential costs to be $0.55/MWh for the Energex NSLP (and CLPs) and $0.42/MWh for the Ergon NSLP. More details on ACIL's approach are available in chapter 4 of its draft report.

We consider ACIL'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 additional benefits in doing so. On this basis, we consider that ACIL'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. ACIL estimated the hedged prudential costs considering:

- the costs of funding the margins—noting that the funds lodged as margins with the ASX receive a money market return that 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 NSLPs.

An additional margin may apply when contract prices move in an unfavourable manner for the buyer or seller of ASX contracts. However, ACIL 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 estimated the 2022–23 hedge prudential costs to be $1.56/MWh for the Energex NSLP (and CLPs) and $1.31/MWh for the Ergon NSLP. More details on ACIL's approach are available in chapter 4 of its draft report.

We consider ACIL's approach to estimating the hedge prudential costs to be appropriate, as it aligns 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 2022–23.

### Reliability and Emergency Reserve Trader scheme

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

ACIL 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)[25], there is currently insufficient data to do so.

Therefore, as with the ancillary services, ACIL proposed to forecast the RERT costs using the costs published by AEMO for the preceding 12-month period. On 25 May 2021, AEMO activated the RERT to assist with power system management following the major incident at the Callide power station. AEMO reported the costs of this activation to be $452,881. By dividing this activation cost with the total energy requirements in Queensland, the RERT cost was estimated to be $0.01/MWh.

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[25] 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.

We consider ACIL's methodology is appropriate, given the highly uncertain nature of the RERT costs—the RERT scheme is only called upon by AEMO under extreme circumstances. AEMO uses the RERT scheme as a safety net if a critical shortfall in reserves is forecast. 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) was implemented on 1 July 2019. The 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 or potential closures of thermal power plants.

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 2022–23, the RRO has not been triggered 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.

## Summary of other energy costs

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

**Figure 11 Other energy costs—LRET and SRES (draft estimates)**

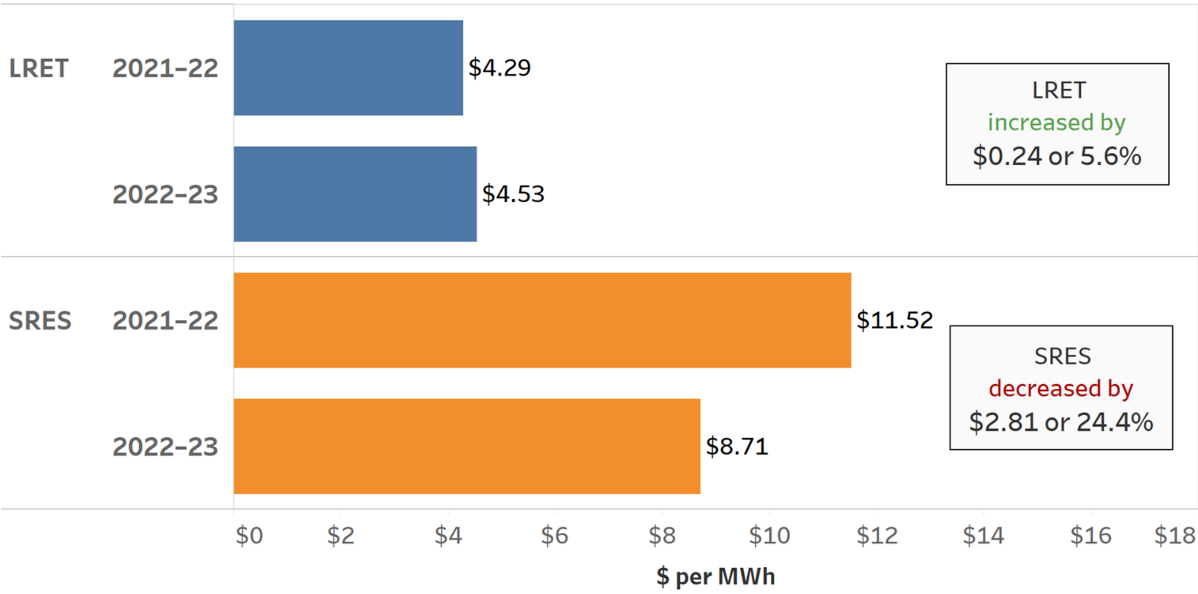


**Figure 12 Other energy costs (draft estimates)**

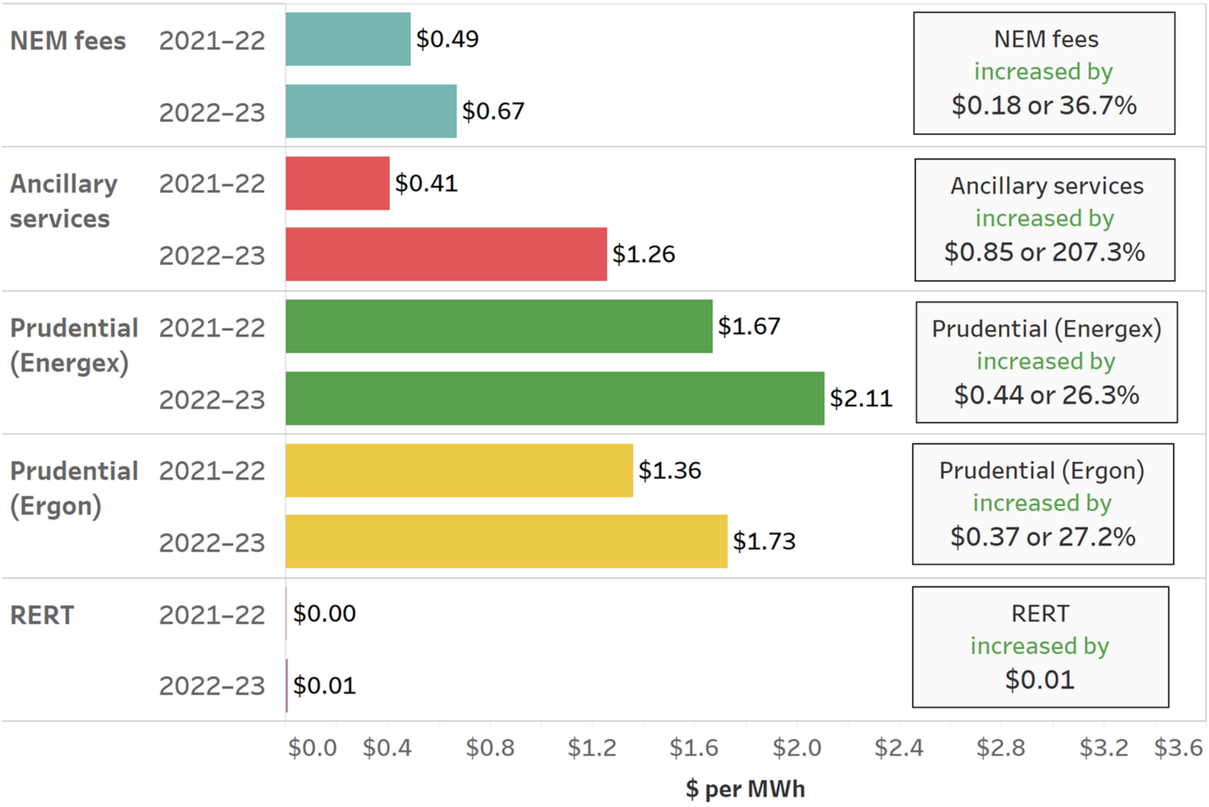
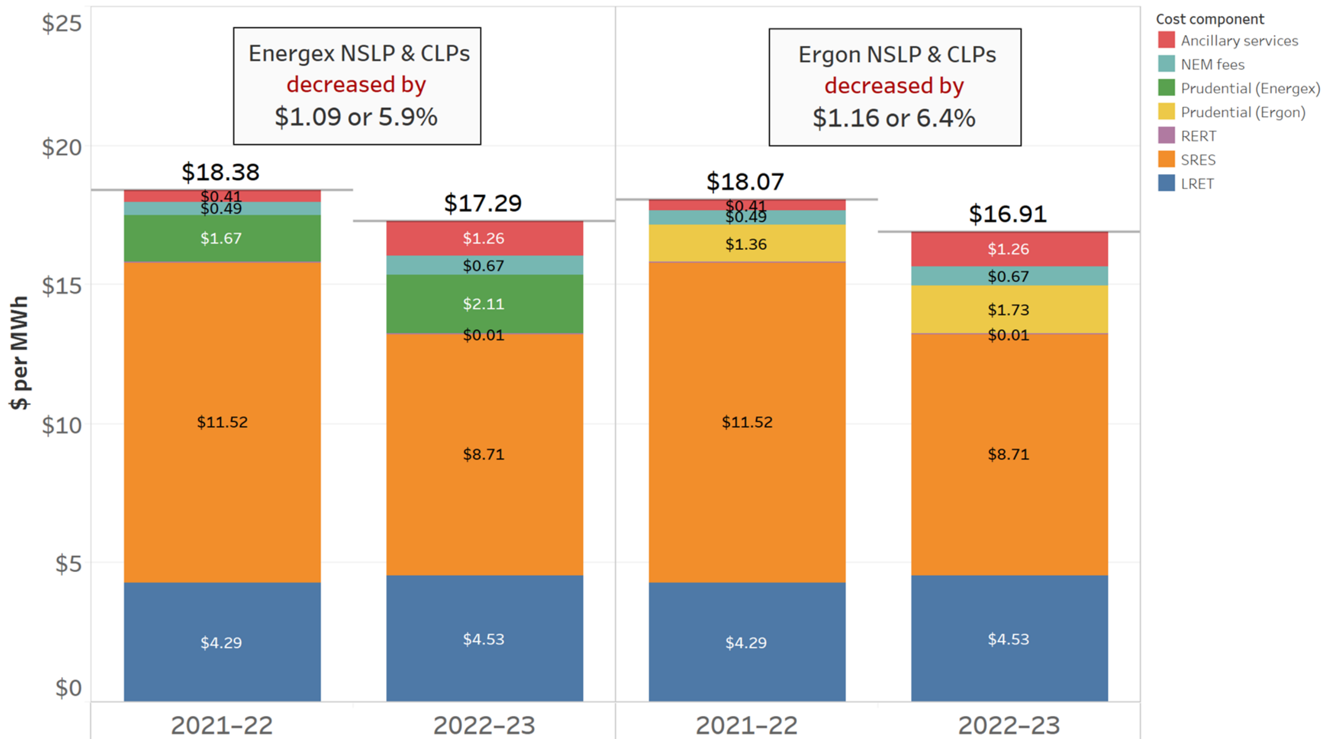



**Figure 13 Total other energy costs (draft estimates)**



## 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 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, using the loss factors and energy consumed at each of the transmission node identities (TNI) provided by AEMO
- the distribution loss factor published by AEMO.

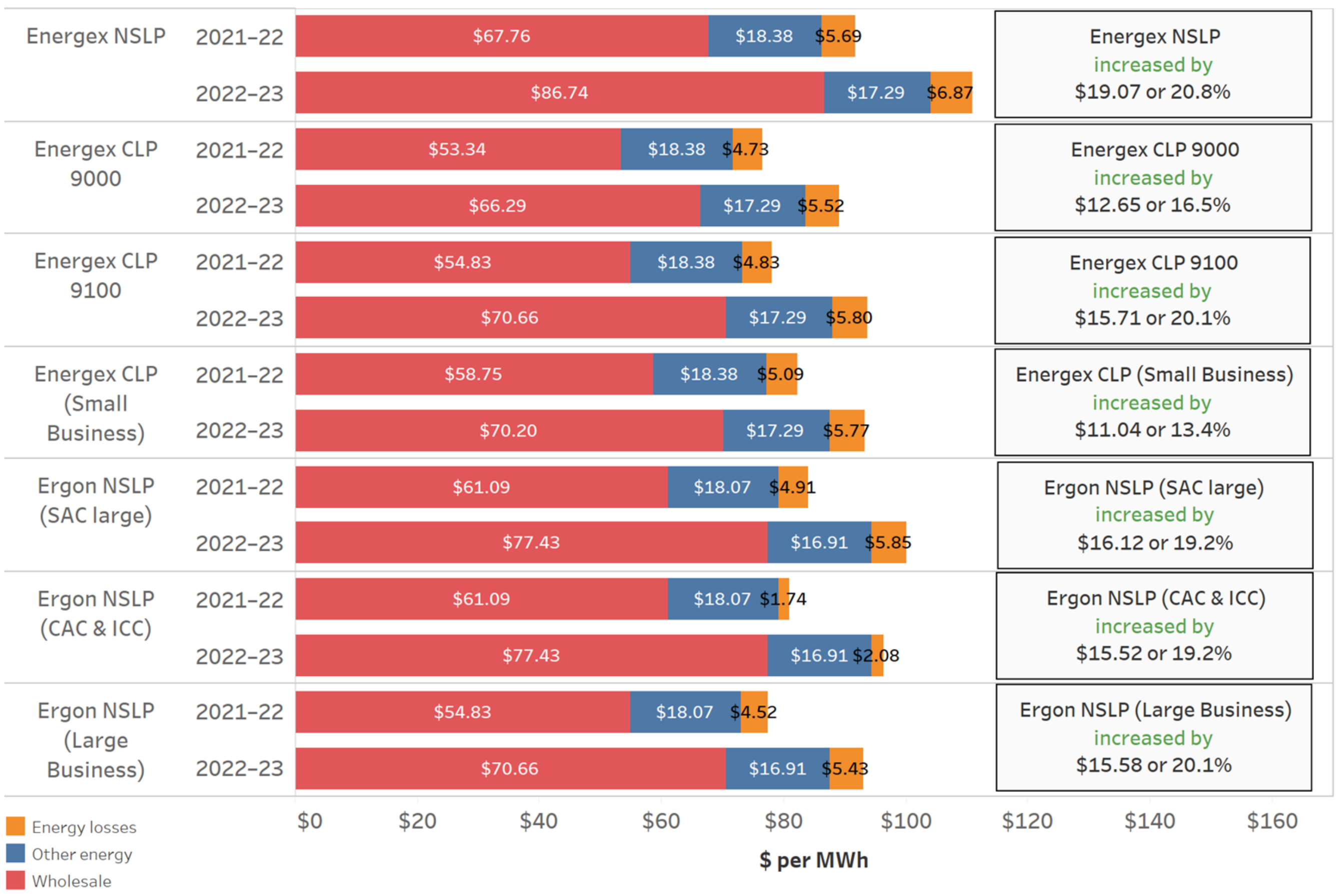
The calculated losses in ACIL's draft report are based on AEMO's 2021–22 published loss factors, as the final loss factors for 2022–23 have not yet been published. ACIL will update the loss factors in its final report, using AEMO's 2022–23 loss factors.

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

## Total energy cost allowances for 2022–23

The chart below summarises the changes in total energy cost allowances for 2022–23.

**Figure 14 Changes in total energy cost allowances (draft estimates)**




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

# APPENDIX D: 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 draft notified prices (discussed in section 5.2).

The approach we used involves the following two steps:

- estimate the under- or over-recovery of SRES costs in 2021–22, and then
- calculate SRES costs to be passed through in the 2022–23 notified prices.

## Estimate the under- or over-recovery of SRES costs in 2021–22

First, we calculated the actual cost of SRES compliance during 2021–22, based on:

- the Clean Energy Regulator's (CER's) final small-scale technology percentage (STP) for 2021
- ACIL 's updated STP for 2022, which reflects the CER's most recent expected uptake in small-scale renewable energy systems.

We then compared the actual cost of SRES compliance to the SRES allowance in the 2021–22 notified prices, which revealed an over-recovery of $1.28/MWh (0.1280 c/kWh) (see Table 2 ).

**Table 2 SRES over-recovery, 2021–22**

| | *Period* | *STP* | | *Clearing house price ($/MWh)[a]* | *SRES cost ($/MWh)* | *Average SRES cost ($/MWh)* |
|---|---|---|---|---|---|---|
| | | *Final (%)* | *Non-binding (%)* | | | |
| 2021–22 final determination allowance | 1 Jul–31 Dec 2021 | 28.80 | – | 40.00 | 11.520 | 11.520 |
| | 1 Jan–30 Jun 2022 | – | 28.80 | 40.00 | 11.520 | |
| 2021–22 actual cost | 1 Jul–31 Dec 2021 | 28.80 | – | 40.00 | 11.520 | 10.240 |
| | 1 Jan–30 Jun 2022 | 22.40[b] | – | 40.00 | 8.960 | |
| Over-recovery in 2021–22 (before adjusting for energy losses, the time value of money, variable retail cost allocators and standing offer adjustment/headroom) | | | | | | 1.28 |

*a Determined by the Clean Energy Regulator.*

*b The CER is expected to determine its final 2022 STP in March 2022, which we will incorporate for our final determination.*

*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 2022–23 notified prices

We adjusted the over-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 2021–22 determination
- the time value of money (to restore the real value of the over-recovered amounts), by applying a nominal weighted-average cost of capital of 7.22 per cent[26]

[26] Based on our latest internal analysis.

- the variable retail cost allocators and standing offer adjustment (consistent with the manner in which these allowances were applied as part of the 2021–22 determination).

Once adjusted, the resulting pass-through amount is included in the draft notified prices (see Table 3).

**Table 3 SRES pass-through amounts**

| | | |
|---|---|---|
| Energex NSLP and controlled load profiles (CLPs)—residential and load control[27] tariffs | | |
| A | SRES over-recovery in 2021–22 (c/kWh) | –0.1280 |
| B | Energy losses in 2021–22 (total loss factor) | 1.066 |
| C | Discount rate (time value of money) | 7.22% |
| D | Over-recovery before the application of standing offer adjustment and variable retail cost allowance (2022–23 c/kWh) | –0.1463 |
| E | Variable retail cost allowance (residential) in 2021–22 (%) | 7.25% |
| F | Standing offer adjustment in 2021–22 (%) | 3.6% |
| G | SRES cost pass-through for 2022–23 (c/kWh) | –0.1626 |
| Energex NSLP and CLPs—small business, load control[28] and unmetered supply tariffs | | |
| A | SRES over-recovery in 2021–22 (c/kWh) | –0.1280 |
| B | Energy losses in 2021–22 (total loss factor) | 1.066 |
| C | Discount rate (time value of money) | 7.22% |
| D | Over-recovery before the application of standing offer adjustment and variable retail cost allowance (2022–23 c/kWh) | –0.1463 |
| E | Variable retail cost allowance (small business) in 2021–22 (%) | 18.70% |
| F | Standing offer adjustment in 2021–22 (%) | 3.6% |
| G | SRES cost pass-through for 2022–23 (c/kWh) | –0.1799 |
| Ergon NSLP and CLPs—large business, load control[29] and street lighting tariffs | | |
| A | SRES over-recovery in 2021–22 (c/kWh) | –0.1280 |
| B | Energy losses in 2021–22 (total loss factor) | 1.062 |
| C | Discount rate (time value of money) | 7.22% |
| D | Over-recovery before the application of headroom and variable retail cost allowance (2022–23 c/kWh) | –0.1458 |
| E | Variable retail cost allowance (large business) in 2021–22 (%) | 6.0445% |
| F | Headroom allowance in 2021–22 (%) | 0.0 |
| G | SRES cost pass-through for 2022–23 (c/kWh) | –0.1546 |
| Ergon Energy NSLP—very large business tariffs | | |
| A | SRES over-recovery in 2021–22 (c/kWh) | –0.1280 |
| B | Energy losses in 2021–22 (total loss factor) | 1.022 |

[27] Tariffs 31 and 33.
[28] Tariff 34.
[29] Tariffs 60A and 60B.

| | | |
|---|---|---|
| C | Discount rate (time value of money) | 7.22% |
| D | Over-recovery before the application of headroom and variable retail cost allowance (2022–23 c/kWh) | –0.1403 |
| E | Variable retail cost allowance (very large business) in 2021–22 (%) | 6.0445% |
| F | Headroom allowance in 2021–22 (%) | 0.0 |
| G | SRES cost pass-through for 2022–23 (c/kWh) | –0.1488 |

*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 E: 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, Ergon Retail has provided the latest actual usage data, gathered from its customer base of over 700,000 electricity customers in regional Queensland.

**Table 4 Median usage data used to determine customer impacts**

| *Retail tariff* | *Usage (kWh per year)* | *Demand (kW per month)* | *Demand threshold (kW per month)* |
|---|---|---|---|
| T11 | 4,296 | | |
| T31 | 1,674 | | |
| T33 | 1,549 | | |
| T20 | 6,580 | | |
| T44 | 139,334 | 46 | 30 |
| T45 | 645,297 | 178 | 120 |
| T46 | 1,403,325 | 465 | 400 |

# APPENDIX F: BUILD-UP OF DRAFT NOTIFIED PRICES

### Table 5 Draft notified prices—residential customers (excl. GST)

| *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 | 52.200 | 7.709 | | | | |
| | Energy | | 11.090 | | | | |
| | Fixed retail | 35.018 | | | | | |
| | Variable retail | | 1.363 | | | | |
| | Standing offer adjustment | 3.227 | 0.746 | | | | |
| | SRES cost pass-through | | –0.1626 | | | | |
| | **Total** | **90.445** | **20.745** | | | | |
| Tariff 12B—residential time-of-use | Network | 51.500 | 3.070 | 3.942 | 14.422 | | |
| | Energy | | 11.090 | 11.090 | 11.090 | | |
| | Fixed retail | 35.018 | | | | | |
| | Variable retail | | 1.027 | 1.090 | 1.850 | | |
| | Standing offer adjustment | 3.201 | 0.562 | 0.596 | 1.012 | | |
| | SRES cost pass-through | | –0.1626 | –0.1626 | –0.1626 | | |
| | **Total** | **89.719** | **15.585** | **16.555** | **28.211** | | |
| Tariff 14A—residential time-of-use demand | Network | 51.500 | 3.984 | | | 3.407 | |
| | Energy | | 11.090 | | | | |
| | Fixed retail | 35.018 | | | | | |
| | Variable retail | | 1.093 | | | 0.247 | |
| | Standing offer adjustment | 3.201 | 0.598 | | | 0.135 | |
| | SRES cost pass-through | | –0.1626 | | | | |
| | Total | **89.719** | **16.602** | | | **3.789** | |
| Tariff 14B—residential time-of-use demand | Network | 49.900 | 2.515 | | | 6.883 | |
| | Energy | | 11.090 | | | | |
| | Fixed retail | 35.018 | | | | | |
| | Variable retail | | 0.986 | | | 0.499 | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Standing offer adjustment | 3.142 | 0.540 | | | 0.273 | |
| | SRES cost pass-through | | –0.1626 | | | | |
| | **Total** | **88.060** | **14.968** | | | **7.655** | |
| Tariff 31—night rate (super economy) | Network | | 3.476 | | | | |
| | Energy | | 8.910 | | | | |
| | Fixed retail | | | | | | |
| | Variable retail | | 0.898 | | | | |
| | Standing offer adjustment | | 0.491 | | | | |
| | SRES cost pass-through | | –0.1626 | | | | |
| | **Total** | | **13.613** | | | | |
| Tariff 33—controlled (supply economy) | Network | | 4.476 | | | | |
| | Energy | | 9.375 | | | | |
| | Fixed retail | | | | | | |
| | Variable retail | | 1.004 | | | | |
| | Standing offer adjustment | | 0.550 | | | | |
| | SRES cost pass-through | | –0.1626 | | | | |
| | **Total** | | **15.243** | | | | |
| ***Tariffs proposed to be made obsolete from 1 July 2022*** | | | | | | | |
| Tariff 12A—residential (time-of-use) | Network | 33.431 | 5.233 | | 36.777 | | |
| | Energy | | 11.090 | | 11.090 | | |
| | Fixed retail | 35.018 | | | | | |
| | Variable retail | | 1.183 | | 3.470 | | |
| | Standing offer adjustment | 2.533 | 0.648 | | 1.899 | | |
| | SRES cost pass-through | | –0.1626 | | –0.1626 | | |
| | **Total** | **70.982** | **17.991** | | **53.074** | | |
| Tariff 14—residential (seasonal time-of-use demand) | Network | 6.805 | 2.195 | | | 6.348 | 44.205 |
| | Energy | | 11.090 | | | | |
| | Fixed retail | 35.018 | | | | | |
| | Variable retail | | 0.963 | | | 0.460 | 3.205 |
| | Standing offer adjustment | 1.547 | 0.527 | | | 0.252 | 1.754 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | SRES cost pass-through | | –0.1626 | | | | |
| | **Total** | **43.371** | **14.613** | | | **7.061** | **49.164** |

***a*** *Charged per metering point.*
*Note: Totals may not add due to rounding.*

### Table 6 Draft notified prices—small business and unmetered supply customers (excl. GST)

| ***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 | 69.600 | 8.353 | | | |
| | Energy | | 11.090 | | | |
| | Fixed retail | 48.963 | | | | |
| | Variable retail | | 3.636 | | | |
| | Standing offer adjustment | 4.387 | 0.854 | | | |
| | SRES cost pass-through | | –0.1799 | | | |
| | **Total** | **122.950** | **23.752** | | | |
| Tariff 24A—business (time-of-use demand) | Network | 68.900 | 5.457 | | 3.253 | |
| | Energy | | 11.090 | | | |
| | Fixed retail | 48.963 | | | | |
| | Variable retail | | 3.094 | | 0.608 | |
| | Standing offer adjustment | 4.361 | 0.727 | | 0.143 | |
| | SRES cost pass-through | | –0.1799 | | | |
| | **Total** | **122.224** | **20.188** | | **4.004** | |
| Tariff 24B—business (time-of-use demand) | Network | 67.000 | 5.135 | | 8.122 | |
| | Energy | | 11.090 | | | |
| | Fixed retail | 48.963 | | | | |
| | Variable retail | | 3.034 | | 1.519 | |
| | Standing offer adjustment | 4.291 | 0.713 | | 0.357 | |
| | SRES cost pass-through | | –0.1799 | | | |
| | **Total** | **120.253** | **19.791** | | **9.998** | |
| | Network | 59.000 | 4.870 | | | |

| ***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 34—business (interruptible supply) | Energy | | 9.326 | | | |
| | Fixed retail | 48.963 | | | | |
| | Variable retail | | 2.655 | | | |
| | Standing offer adjustment | 3.995 | 0.623 | | | |
| | SRES cost pass-through | | –0.1799 | | | |
| | **Total** | **111.957** | **17.295** | | | |
| Tariff 91—unmetered | Network | | 5.983 | | | |
| | Energy | | 11.090 | | | |
| | Fixed retail | | | | | |
| | Variable retail | | 3.193 | | | |
| | Standing offer adjustment | | 0.750 | | | |
| | SRES cost pass-through | | –0.1799 | | | |
| | **Total** | | **20.835** | | | |
| ***Tariffs proposed to be made obsolete from 1 July 2022*** | | | | | | |
| Tariff 22A—business (seasonal time-of-use) | Network | 58.779 | 7.352 | 34.955 | | |
| | Energy | | 11.090 | 11.090 | | |
| | Fixed retail | 48.963 | | | | |
| | Variable retail | | 3.449 | 8.610 | | |
| | Standing offer adjustment | 3.986 | 0.810 | 2.022 | | |
| | SRES cost pass-through | | –0.1799 | –0.1799 | | |
| | **Total** | **111.728** | **22.520** | **56.498** | | |
| Tariff 24—business (seasonal time-of-use demand) | Network | 7.371 | 2.857 | | 6.041 | 60.115 |
| | Energy | | 11.090 | | | |
| | Fixed retail | 48.963 | | | | |
| | Variable retail | | 2.608 | | 1.130 | 11.241 |
| | Standing offer adjustment | 2.084 | 0.613 | | 0.265 | 2.640 |
| | SRES cost pass-through | | –0.1799 | | | |
| | **Total** | **58.418** | **16.987** | | **7.436** | **73.996** |

| *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 41—business low voltage (demand) | Network | 533.700 | 1.204 | | 15.253 | |
| | Energy | | 11.090 | | | |
| | Fixed retail | 48.963 | | | | |
| | Variable retail | | 2.299 | | 2.852 | |
| | Standing offer adjustment | 21.559 | 0.540 | | 0.670 | |
| | SRES cost pass-through | | –0.1799 | | | |
| | **Total** | **604.221** | **14.952** | | **18.775** | |

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

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

## Table 7 Draft notified prices—small business customers (excl. GST)

| *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 22B—small business time-of-use inclining band | Network | 68.900 | 97.500 | 126.000 | 154.600 | 183.100 | 3.108 | 7.594 | 15.892 |
| | Energy | | | | | | 11.090 | 11.090 | 11.090 |
| | Fixed retail | 48.963 | 48.963 | 48.963 | 48.963 | 48.963 | | | |
| | Variable retail | | | | | | 2.655 | 3.494 | 5.046 |
| | Standing offer adjustment | 4.361 | 5.419 | 6.474 | 7.532 | 8.586 | 0.624 | 0.821 | 1.185 |
| | SRES cost pass-through | | | | | | –0.1799 | –0.1799 | –0.1799 |
| | **Total** | **122.224** | **151.882** | **181.436** | **211.095** | **240.649** | **17.296** | **22.818** | **33.032** |
| ***Tariffs proposed to be extinguished from 1 July 2022*** | | | | | | | | | |
| Tariff 20A—small business inclining-band | Network | 68.200 | 96.300 | 124.500 | 152.700 | 180.900 | 8.365 | | |
| | Energy | | | | | | 11.090 | | |
| | Fixed retail | 48.963 | 48.963 | 48.963 | 48.963 | 48.963 | | | |
| | Variable retail | | | | | | 3.638 | | |
| | Standing offer adjustment | 4.335 | 5.375 | 6.418 | 7.462 | 8.505 | 0.854 | | |
| | SRES cost pass-through | | | | | | –0.1799 | | |
| | **Total** | **121.498** | **150.638** | **179.881** | **209.124** | **238.368** | **23.767** | | |

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

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

**Table 8 Draft 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 | 3754.000 | 2.707 | | 22.681 | | 20.413 | |
| | Energy | | 10.019 | | | | | |
| | Fixed retail | 398.510 | | | | | | |
| | Variable retail | | 0.769 | | 1.371 | | 1.234 | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | –0.1546 | | | | | |
| | **Total** | **4152.510** | **13.341** | | **24.052** | | **21.647** | |
| Tariff 45—over 100 MWh medium (demand) | Network | 12407.100 | 2.707 | | 20.851 | | 18.766 | |
| | Energy | | 10.019 | | | | | |
| | Fixed retail | 1095.991 | | | | | | |
| | Variable retail | | 0.769 | | 1.260 | | 1.134 | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | –0.1546 | | | | | |
| | **Total** | **13503.091** | **13.341** | | **22.111** | | **19.900** | |
| Tariff 46—over 100 MWh large (demand) | Network | 32419.300 | 2.707 | | 17.087 | | 15.378 | |
| | Energy | | 10.019 | | | | | |
| | Fixed retail | 2788.022 | | | | | | |
| | Variable retail | | 0.769 | | 1.033 | | 0.930 | |
| | 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 | | –0.1546 | | | | | |
| | **Total** | **35207.322** | **13.341** | | **18.120** | | **16.308** | |
| Tariff 50A—large business time-of-use demand | Network | 17074.800 | 2.945 | | | | 13.400 | 2.680 |
| | Energy | | 10.019 | | | | | |
| | Fixed retail | 358.891 | | | | | | |
| | Variable retail | | 0.784 | | | | 0.810 | 0.162 |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | –0.1546 | | | | | |
| | **Total** | **17433.691** | **13.593** | | | | **14.210** | **2.842** |
| Tariff 60A—large business flat-rate interruptible supply (primary) | Network | 3754.000 | 11.452 | | | | | |
| | Energy | | 9.300 | | | | | |
| | Fixed retail | 398.510 | | | | | | |
| | Variable retail | | 1.254 | | | | | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | –0.1546 | | | | | |
| | **Total** | **4152.510** | **21.852** | | | | | |
| Tariff 60B—large business flat-rate interruptible supply (secondary) | Network | | 11.452 | | | | | |
| | Energy | | 9.300 | | | | | |
| | Fixed retail | | | | | | | |
| | Variable retail | | 1.254 | | | | | |

| 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 | | –0.1546 | | | | | |
| | **Total** | | **21.852** | | | | | |
| Tariff 71—street lighting | Network | | 15.461 | | | | | |
| | Energy | | 10.019 | | | | | |
| | Fixed retail | | | | | | | |
| | Variable retail | | 1.540 | | | | | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | –0.1546 | | | | | |
| | **Total** | | **26.865** | | | | | |
| ***Tariffs proposed to be made obsolete from 1 July 2022*** | | | | | | | | |
| Tariff 50—over 100 MWh seasonal time-of-use (demand) | Network | 3138.500 | 5.605 | 1.147 | 10.222 | 67.062 | | |
| | Energy | | 10.019 | 10.019 | | | | |
| | Fixed retail | 358.891 | | | | | | |
| | Variable retail | | 0.944 | 0.675 | 0.618 | 4.054 | | |
| | Headroom | | | | | | | |
| | SRES cost pass-through | | –0.1546 | –0.1546 | | | | |
| | **Total** | **3497.391** | **16.414** | **11.686** | **10.840** | **71.116** | | |

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

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

**Table 9 Draft 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 | 22281.700 | 1.734 | 6.343 | 3.438 | 3.162 |
| | Energy | | 9.642 | | | |
| | Fixed retail | 2759.839 | | | | |
| | Variable retail | | 0.688 | 0.383 | 0.208 | 0.191 |
| | Headroom | | | | | |
| | SRES cost pass-through | | –0.1488 | | | |
| | **Total** | **25041.539** | **11.914** | **6.726** | **3.646** | **3.353** |
| Tariff 51B—high voltage (CAC 33 kV) | Network | 15357.700 | 1.734 | 6.343 | 4.198 | 3.275 |
| | Energy | | 9.642 | | | |
| | Fixed retail | 2759.839 | | | | |
| | Variable retail | | 0.688 | 0.383 | 0.254 | 0.198 |
| | Headroom | | | | | |
| | SRES cost pass-through | | –0.1488 | | | |
| | **Total** | **18117.539** | **11.914** | **6.726** | **4.452** | **3.473** |
| Tariff 51C—high voltage (CAC 22/11kV Bus) | Network | 14158.400 | 1.734 | 6.343 | 4.841 | 3.971 |
| | Energy | | 9.642 | | | |
| | Fixed retail | 2759.839 | | | | |
| | Variable retail | | 0.688 | 0.383 | 0.293 | 0.240 |
| | Headroom | | | | | |

| ***Retail tariff*** | ***Tariff component*** | ***Fixed***[a] | ***Usage*** | ***Connection unit*** | ***Capacity*** | ***Demand*** |
|---|---|---|---|---|---|---|
| | | ***c/day*** | ***c/kWh*** | ***$/day/unit*** | ***$/kVA of AD/mth*** | ***$/kVA/mth*** |
| | SRES cost pass-through | | –0.1488 | | | |
| | **Total** | **16918.239** | **11.914** | **6.726** | **5.134** | **4.211** |
| Tariff 51D—high voltage (CAC 22/11kV Line) | Network | 13473.000 | 1.734 | 6.343 | 9.378 | 8.010 |
| | Energy | | 9.642 | | | |
| | Fixed retail | 2759.839 | | | | |
| | Variable retail | | 0.688 | 0.383 | 0.567 | 0.484 |
| | Headroom | | | | | |
| | SRES cost pass-through | | –0.1488 | | | |
| | **Total** | **16232.839** | **11.914** | **6.726** | **9.945** | **8.494** |
| Tariff 53—high voltage (ICC) | Network | 22281.700 | 1.734 | | 3.438 | 3.162 |
| | Energy | | 9.642 | | | |
| | Fixed retail | 2569.121 | | | | |
| | Variable retail | | 0.688 | | 0.208 | 0.191 |
| | Headroom | | | | | |
| | SRES cost pass-through | | –0.1488 | | | |
| | **Total** | **24850.821** | **11.914** | | **3.646** | **3.353** |
| ICC site-specific—high voltage | Energy | | 9.642 | | | |
| | Fixed retail | 2569.121 | | | | |
| | Variable retail | | 0.688 | | 0.208 | 0.191 |
| | Headroom | | | | | |
| | SRES cost pass-through | | –0.1488 | | | |

| Retail tariff | Tariff component | Fixed[a] | Usage | Connection unit | Capacity | Demand |
|---|---|---|---|---|---|---|
| | | c/day | c/kWh | $/day/unit | $/kVA of AD/mth | $/kVA/mth |
| | **Total** | **2569.121** | **10.180** | | **0.208** | **0.191** |

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

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

**Table 10 Draft 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 | 10646.000 | 1.539 | 0.954 | 6.343 | 5.947 | 12.302 |
| | Energy | | 9.642 | 9.642 | | | |
| | Fixed retail | 2759.839 | | | | | |
| | Variable retail | | 0.676 | 0.640 | 0.383 | 0.359 | 0.744 |
| | Headroom | | | | | | |
| | SRES cost pass-through | | –0.1488 | –0.1488 | | | |
| | **Total** | **13405.839** | **11.708** | **11.087** | **6.726** | **6.306** | **13.046** |
| Tariff 52B—high voltage (CAC STOUD 22/11kV Bus) | Network | 10646.000 | 1.539 | 0.954 | 6.343 | 4.204 | 43.992 |
| | Energy | | 9.642 | 9.642 | | | |
| | Fixed retail | 2759.839 | | | | | |
| | Variable retail | | 0.676 | 0.640 | 0.383 | 0.254 | 2.659 |
| | Headroom | | | | | | |
| | SRES cost pass-through | | –0.1488 | –0.1488 | | | |
| | **Total** | **13405.839** | **11.708** | **11.087** | **6.726** | **4.458** | **46.651** |
| Tariff 52C—high voltage (CAC STOUD 22/11kV Line) | Network | 10646.000 | 1.539 | 0.954 | 6.343 | 7.690 | 67.912 |
| | Energy | | 9.642 | 9.642 | | | |
| | Fixed retail | 2759.839 | | | | | |
| | Variable retail | | 0.676 | 0.640 | 0.383 | 0.465 | 4.105 |
| | Headroom | | | | | | |

| ***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*** |
| | SRES cost pass-through | | –0.1488 | –0.1488 | | | |
| | **Total** | **13405.839** | **11.708** | **11.087** | **6.726** | **8.155** | **72.017** |

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

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

## Table 11 Draft 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 | 3754.000 | 2.707 | 11.102 |
| | Energy | | 10.019 | 10.019 |
| | Fixed retail | 398.510 | | |
| | Variable retail | | 0.769 | 1.277 |
| | Headroom | | | |
| | SRES cost pass-through | | –0.1546 | –0.1546 |
| | **Total** | **4152.510** | **13.341** | **22.243** |

***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 12 Draft 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 | 57.300 | 39.308 | 31.293 | 5.744 | | |
| | Energy | | 10.019 | 10.019 | 10.019 | | |
| | Fixed retail | 49.406 | | | | | |
| | Variable retail | | 9.224 | 7.725 | 2.948 | | |
| | Headroom | | | | | | |
| | SRES cost pass-through | | –0.1546 | –0.1546 | –0.1546 | | |
| | **Total** | **106.706** | **58.396** | **48.883** | **18.556** | | |
| Tariff 65A—time-of-use tariff[c] | Network | 57.000 | 28.675 | | 10.126 | | |
| | Energy | | 10.019 | | 10.019 | | |
| | Fixed retail | 49.406 | | | | | |
| | Variable retail | | 7.236 | | 3.767 | | |
| | Headroom | | | | | | |
| | SRES cost pass-through | | –0.1546 | | –0.1546 | | |
| | **Total** | **106.406** | **45.775** | | **23.757** | | |
| Tariff 66A—dual-rate demand tariff | Network | 175.100 | | | 8.984 | 3.469 | 10.474 |
| | Energy | | | | 10.019 | | |
| | Fixed retail | 49.406 | | | | | |
| | Variable retail | | | | 3.554 | 0.649 | 1.959 |
| | 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 | | | | –0.1546 | | |
| | **Total** | **224.506** | | | **22.402** | **4.118** | **12.433** |

***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 G: DRAFT 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~~ June 2021~~0~~.

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~~16 December~~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 2022~~1~~, 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~~11th~~ day of MMMM~~June~~ 2022~~1~~.

**~~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 the 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.

***Tariff~~s 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~~ is~~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 | 20.745 | c/kWh |
| | | Daily supply charge | 90.445 | c |
| ~~12A~~ | ~~Residential seasonal time-of-use primary tariff~~ | ~~Usage – Peak (Summer 3pm–9:30pm)~~ | | ~~c/kWh~~ |
| | | ~~Usage – All other times~~ | | ~~c/kWh~~ |
| | | ~~Daily supply charge~~ | | ~~c~~ |
| 12B | Residential time-of-use primary tariff | Usage: | | |
| | | Peak (4pm – 9pm) | 28.211 | c/kWh |
| | | Day (9am – 4pm) | 15.585 | c/kWh |
| | | Night (all other times) | 16.555 | c/kWh |
| | | Daily supply charge | 89.719 | c |
| ~~14~~ | ~~Residential seasonal time-of-use monthly demand primary tariff.~~ | ~~Chargeable demand – Peak~~ | | ~~$/kW~~ |
| | ~~*Peak daily demand* is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm during Summer.~~ | ~~Chargeable Demand – Off peak~~ | | ~~$/kW~~ |
| | ~~*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.~~ | ~~Usage~~ | | ~~c/kWh~~ |
| | ~~*Peak chargeable demand* is the average of the four highest peak daily demands in the month.~~ | ~~Daily supply charge~~ | | ~~c~~ |
| | ~~*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) | 3.789 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 16.602 | c/kWh |
| | | Daily supply charge | 89.719 | c |

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| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 14B | Residential time-of-use monthly demand primary tariff. | Demand:<br>Peak (4pm – 9pm) | 7.655 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 14.968 | c/kWh |
| | | Daily supply charge | 88.060 | c |
| 20 | Small business flat-rate primary tariff. | Usage | 23.752 | c/kWh |
| | | Daily supply charge | 122.950 | c |
| ~~20A~~ | ~~Small business inclining-band primary tariff.~~ | ~~Usage~~ | | ~~c/kWh~~ |
| | | ~~Daily supply charge:~~<br>~~Band 1~~ | | ~~c~~ |
| | | ~~Band 2~~ | | ~~c~~ |
| | | ~~Band 3~~ | | ~~c~~ |
| | | ~~Band 4~~ | | ~~c~~ |
| | | ~~Band 5~~ | | ~~c~~ |
| ~~22A~~ | ~~Small business seasonal time-of-use primary tariff.~~ | ~~Usage – Peak (Summer 10am–8pm weekdays)~~ | | ~~c/kWh~~ |
| | | ~~Usage – All other times~~ | | ~~c/kWh~~ |
| | | ~~Daily supply charge~~ | | ~~c~~ |
| 22B | Small business time-of-use inclining-band primary tariff. | Usage:<br>Peak (4pm – 9pm weekdays) | 33.032 | c/kWh |
| | | Day (9am – 4pm) | 17.296 | c/kWh |
| | | Night (all other times) | 22.818 | c/kWh |
| | | Daily supply charge:<br>Band 1 | 122.224 | c |
| | | Band 2 | 151.882 | c |
| | | Band 3 | 181.436 | c |
| | | Band 4 | 211.095 | c |
| | | Band 5 | 240.649 | c |

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| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| ~~24~~ | ~~Small business seasonal time-of-use monthly demand primary tariff.~~ | ~~Chargeable demand – Peak~~ | | ~~$/kW~~ |
| | ~~*Peak daily demand* is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm during Summer.~~ | ~~Chargeable Demand – Off peak~~ | | ~~$/kW~~ |
| | | ~~Usage~~ | | ~~c/kWh~~ |
| | ~~*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.~~ | ~~Daily supply charge~~ | | ~~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.~~ | | | |
| 24A | Small business time-of-use monthly demand primary tariff. | Demand:<br>Peak (4pm – 9pm weekdays) | 4.004 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 20.188 | c/kWh |
| | | Daily supply charge | 122.224 | c |
| 24B | Small business time-of-use monthly demand primary tariff. | Demand:<br>Peak (4pm – 9pm weekdays) | 9.998 | $/kW |
| | | All other times | 0.0 | $/kW |
| | | Usage | 19.791 | c/kWh |
| | | Daily supply charge | 120.253 | c |
| 31 | Small customer flat-rate secondary tariff with interruptible supply. | Usage | 13.613 | c/kWh |
| 33 | Small customer flat-rate secondary tariff with interruptible supply. | Usage | 15.243 | c/kWh |
| 34 | Small business flat-rate primary tariff with interruptible supply. | Usage | 17.295 | c/kWh |
| | | Daily supply charge | 111.957 | c |
| ~~41~~ | ~~Small business monthly demand primary tariff.~~ | ~~Demand~~ | | ~~$/kW~~ |
| | | ~~Usage~~ | | ~~c/kWh~~ |
| | | ~~Daily supply charge~~ | | ~~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 | 13.341 | c/kWh |
| | | all remaining usage | 22.243 | c/kWh |
| | | Daily supply charge | 4152.510 | c |
| 44 | Large business monthly demand primary tariff | Chargeable demand; or | 24.052 | $/kW |
| | Demand threshold 30 kW / 35 kVA. | Chargeable demand | 21.647 | $/kVA |
| | | Usage | 13.341 | c/kWh |
| | | Daily supply charge | 4152.510 | c |
| 45 | Large business monthly demand primary tariff | Chargeable demand; or | 22.111 | $/kW |
| | Demand threshold 120 kW / 135 kVA. | Chargeable demand | 19.900 | $/kVA |
| | | Usage | 13.341 | c/kWh |
| | | Daily supply charge | 13503.091 | c |
| 46 | Large business monthly demand primary tariff | Chargeable demand; or | 18.120 | $/kW |
| | Demand threshold 400 kW / 450 kVA. | Chargeable demand | 16.308 | $/kVA |
| | | Usage | 13.341 | c/kWh |
| | | Daily supply charge | 35207.322 | c |
| ~~50~~ | ~~Large business seasonal time-of-use monthly demand primary tariff.~~ | ~~Peak chargeable demand~~ | | ~~$/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~~ | | ~~$/kW~~ |
| | ~~Off-peak is all times in non-summer months for determining chargeable demand and usage.~~ | ~~Peak usage~~ | | ~~c/kWh~~ |
| | ~~Peak demand threshold 20 kW.~~ | ~~Off-peak usage~~ | | ~~c/kWh~~ |
| | ~~Off-peak demand threshold 40 kW.~~ | ~~Daily supply charge~~ | | ~~c~~ |
| 50A | Large business time-of-use monthly demand primary tariff. | Demand: | | |
| | | Peak (4pm – 9pm weekdays) | 14.210 | $/kVA |
| | | Excess | 2.842 | $/kVA |
| | | Usage | 13.593 | c/kWh |
| | | Daily supply charge | 17433.691 | 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 | 3.353 | $/kVA |
| | | Capacity | 3.646 | $/kVA |
| | | Usage | 11.914 | c/kWh |
| | | Daily connection charge | 6.726 | $/unit |
| | | Daily supply charge | 25041.539 | c |
| 51B | Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 33kV. | Demand | 3.473 | $/kVA |
| | | Capacity | 4.452 | $/kVA |
| | | Usage | 11.914 | c/kWh |
| | | Daily connection charge | 6.726 | $/unit |
| | | Daily supply charge | 18117.539 | 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 | 4.211 | $/kVA |
| | | Capacity | 5.134 | $/kVA |
| | | Usage | 11.914 | c/kWh |
| | | Daily connection charge | 6.726 | $/unit |
| | | Daily supply charge | 16918.239 | 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 | 8.494 | $/kVA |
| | | Capacity | 9.945 | $/kVA |
| | | Usage | 11.914 | c/kWh |
| | | Daily connection charge | 6.726 | $/unit |
| | | Daily supply charge | 16232.839 | 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. | Chargeable demand | 13.046 | $/kVA |
| | Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. | Chargeable capacity | 6.306 | $/kVA |
| | Chargeable capacity excludes all demands occurring during the chargeable demand periods. | Usage – Summer | 11.087 | c/kWh |
| | | Usage – All other times | 11.708 | c/kWh |
| | | Daily connection charge | 6.726 | $/unit |
| | | Daily supply charge | 13405.839 | c |

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| 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 | 46.651 | $/kVA |
| | | Chargeable capacity | 4.458 | $/kVA |
| | | Usage – Summer | 11.087 | c/kWh |
| | | Usage – All other times | 11.708 | c/kWh |
| | | Daily connection charge | 6.726 | $/unit |
| | | Daily supply charge | 13405.839 | 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 | 72.017 | $/kVA |
| | | Chargeable capacity | 8.155 | $/kVA |
| | | Usage – Summer | 11.087 | c/kWh |
| | | Usage – All other times | 11.708 | c/kWh |
| | | Daily connection charge | 6.726 | $/unit |
| | | Daily supply charge | 13405.839 | c |
| 53 | Large business high-voltage monthly primary tariff only for customers classified as ICC. | Demand | 3.353 | $/kVA |
| | | Capacity | 3.646 | $/kVA |
| | | Usage | 11.914 | c/kWh |
| | | Daily supply charge | 24850.821 | 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 | 0.191 | $/kVA |
| | | Capacity | 0.208 | $/kVA |
| | | Usage | 10.180 | c/kWh |
| | | Daily supply charge | 2569.121 | c |
| 60A | Large business flat-rate primary tariff with interruptible supply. | Usage | 21.852 | c/kWh |
| | | Daily supply charge | 4152.510 | c |
| 60B | Large business flat-rate secondary tariff with interruptible supply. | Usage | 21.852 | c/kWh |

**Unmetered supply tariffs**

| Tariff | Description | Charge type | Rate | Unit |
|---|---|---|---|---|
| 71 | Business flat-rate primary tariff for street lighting. | Usage | 26.865 | c/kWh |
| 91 | Business flat-rate primary tariff. | Usage | 20.835 | 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 |
|---|---|---|---|---|
| 12A | Obsolete residential seasonal time-of-use primary tariff<br><br>Scheduled phase-out date: 30 June 2023 | Usage – Peak (Summer 3pm-9:30pm) | 53.074 | c/kWh |
| | | Usage – All other times | 17.991 | c/kWh |
| | | Daily supply charge | 70.982 | c |
| 14 | Obsolete residential seasonal time-of-use monthly demand primary tariff.<br><br>*Peak daily demand* is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm during Summer.<br><br>*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.<br><br>*Peak chargeable demand* is the average of the four highest peak daily demands in the month.<br><br>*Off-peak chargeable demand* is the greater of the average of the four highest off-peak daily demands in the month, or 3kW.<br><br>Scheduled phase-out date: 30 June 2023 | Chargeable demand – Peak | 49.164 | $/kW |
| | | Chargeable Demand – Off peak | 7.061 | $/kW |
| | | Usage | 14.613 | c/kWh |
| | | Daily supply charge | 43.371 | c |
| 22A | Obsolete small business seasonal time-of-use primary tariff.<br><br>Scheduled phase-out date: 30 June 2023 | Usage – Peak (Summer 10am–8pm weekdays) | 56.498 | c/kWh |
| | | Usage – All other times | 22.520 | c/kWh |
| | | Daily supply charge | 111.728 | c |

| Tariff | Description | Charge type | *Rate* | Unit |
|---|---|---|---|---|
| 24 | Obsolete 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.<br>Scheduled phase-out date: 30 June 2023 | Chargeable demand – Peak | 73.996 | $/kW |
| | | Chargeable Demand – Off peak | 7.436 | $/kW |
| | | Usage | 16.987 | c/kWh |
| | | Daily supply charge | 58.418 | c |
| 41 | Obsolete small business monthly demand primary tariff.<br>Scheduled phase-out date: 30 June 2023 | Demand | 18.775 | $/kW |
| | | Usage | 14.952 | c/kWh |
| | | Daily supply charge | 604.221 | c |
| 50 | Obsolete large business seasonal time-of-use monthly demand primary tariff.<br>Peak is Summer, being 10:00am to 8:00pm on Summer weekdays for determining chargeable demand, and all day each day for usage.<br>Off-peak is all times in non-summer months for determining chargeable demand and usage.<br>Peak demand threshold 20 kW.<br>Off peak demand threshold 40 kW.<br>Scheduled phase-out date: 30 June 2023 | Peak chargeable demand | 71.116 | $/kW |
| | | Off-peak chargeable demand | 10.840 | $/kW |
| | | Peak usage | 11.686 | c/kWh |
| | | Off-peak usage | 16.414 | c/kWh |
| | | Daily supply charge | 3497.391 | c |
| ~~47~~ | ~~Obsolete large business high voltage monthly demand primary tariff.~~<br>~~Demand threshold 400 kW~~<br>~~Scheduled phase-out date: 1 July 2022~~ | ~~Chargeable demand~~ | | ~~$/kW~~ |
| | | ~~Usage~~ | | ~~c/kWh~~ |
| | | ~~Daily supply charge~~ | | ~~c~~ |
| ~~48~~ | ~~Obsolete large business high voltage monthly demand primary tariff only~~ | ~~Chargeable demand~~ | | ~~$/kW~~ |
| | | ~~Usage~~ | | ~~c/kWh~~ |
| | | ~~Daily supply charge~~ | | ~~c~~ |

| Tariff | Description | Charge type | *Rate* | Unit |
|---|---|---|---|---|
| | ~~for customers classified as CAC or ICC.~~<br>~~Demand threshold 400 kW~~<br>~~Scheduled phase-out date: 1 July 2022~~ | | | |
| 62A | Limited-access obsolete small business time-of-use declining-block primary tariff.<br>Scheduled phase-out date: To be confirmed | Usage – 7am to 9pm weekdays: | | |
| | | first 10,000 kWh/month | 58.396 | c/kWh |
| | | remaining | 48.883 | c/kWh |
| | | Usage – all other times | 18.556 | c/kWh |
| | | Daily supply charge | 106.706 | c |
| 65A | Limited-access obsolete small business time-of-use primary tariff.<br>Scheduled phase-out date: To be confirmed | Usage – Peak (daily pricing period) | 45.775 | c/kWh |
| | | Usage – all other times | 23.757 | c/kWh |
| | | Daily supply charge | 106.406 | c |
| 66A | Limited-access obsolete small business fixed dual-rate demand primary tariff.<br>Scheduled phase-out date: To be confirmed | Fixed charge (monthly) – first 7.5kW | 4.118 | $/kW |
| | | Fixed charge (monthly) – remaining kW | 12.433 | $/kW |
| | | Usage | 22.402 | c/kWh |
| | | Daily supply charge | 224.506 | 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 | 207.603 | c |
| Standard asset customer (annual consumption greater than 750MWh) | Daily metering charge | 249.175 | c |
| Connection asset customer | Daily metering charge | 429.569 | c |
| Individually calculated customer | Daily metering charge | 400.498 | c |

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

| Description | Charge type | Rate | Unit |
|---|---|---|---|
| Primary tariff | Daily capital charge | 7.320 | c |
| | Daily non-capital charge | 3.430 | c |
| Secondary tariff~~*~~ (per tariff) | Daily capital charge | 2.115 | c |
| | Daily non-capital charge | 1.018 | 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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