Queensland Competition Authority

Technical appendices—Final determination

Regulated retail electricity prices for 2020–21

Regional Queensland

June 2020

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STRUCTURE OF TECHNICAL APPENDIX

This technical appendix provides supporting and other information relevant to setting prices and final notified prices (contained in the main report). It is designed to be read in conjunction with the main report (not as a substitute).

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APPENDIX A: MINISTER'S DELEGATION

Queensland Government

The Hon Dr Anthony Lynham MP
Minister for Natural Resources, Mines and Energy

Ref CTS 23694/19

10 DEC 2019

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Professor Flavio Menezes
Chair
Queensland Competition Authority
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Dear Professor Menezes

Pursuant to section 90AA of the Electricity Act 1994 (the Act), I have delegated to the Queensland Competition Authority (QCA) my functions under section 90(1) of the Act for the determination of regulated retail electricity prices in regional Queensland for 2020–21. I enclose a copy of the delegation, which includes the terms of reference of the price determination.

The government's uniform tariff policy (UTP) and costs to consumers are important considerations when setting regulated retail electricity prices in regional Queensland. The attached delegation and terms of reference for 2020–21 are generally consistent with the approaches in my delegation and terms of reference for 2019–20, however, there are some important additional considerations. Many of these are associated with managing potential adverse impacts on retail customers of the anticipated changes to network tariffs, including continued advancement of network tariff reform by Queensland's electricity distributors and the Australian Energy Regulator (AER) as well as the commencement of the new 2020-25 distribution regulatory control period.

Network tariff reform is critical to sending the right pricing signals to electricity retailers so that electricity networks are utilised more efficiently, generating savings that flow through to customers in the form of reduced network charges. However, in general, network tariff reform should not create perceptions of differential treatment amongst a class of retail customers based on their geographical location or the type of meter they have. It is important regional customers continue to access price structures that are similar to those accessed by the majority of similar South East Queensland customers, unless they specifically choose an alternate tariff. I am also seeking to ensure all current standard retail tariffs (standard tariffs) are retained in their current form, and where practicable, customers are provided new and additional choice of retail tariffs resulting from the national network tariff reform agenda.

In 2019, the AER set Default Market Offers (DMO) as maximum bill amounts at certain consumption levels in applicable distribution areas in the national electricity market. Under the UTP, the South East Queensland DMO represents the ceiling that should be set for an equivalent notified price. Further, the government notes that standard contracts provide additional value to customers compared to market contracts, for example, through additional protections contained in the terms and conditions of standard contracts.

In order to reflect the intent of the UTP when network tariffs are undergoing significant reform and to maintain existing standard tariff arrangements, I have provided clarity about the scope and application of the UTP. The QCA should also give consideration to including an adjustment in notified prices that appropriately reflects the additional value of the terms and conditions of standard retail contracts. In addition, I consider the standing offer adjustment made by the QCA in previous determinations appropriately reflects this additional value and as such, the QCA should consider including an adjustment of a similar magnitude in notified prices for 2020–21 while ensuring that notified prices do not exceed the equivalent South East Queensland DMO where set.

Under national Power of Choice reforms, all new and replacement meters must be advanced digital meters. Due to my concerns about the cost impact on small customers and the limited realisation of benefits being delivered to customers, on 5 April 2019, I asked the QCA for advice on the benefits of the digital meter roll out in Queensland. As the government remains concerned about the cost of digital meters for small customers and the slow progress toward benefit realisation by the electricity supply industry as identified by the QCA, this delegation again excludes the determination of notified prices for retail metering services for residential and small business customers. I intend to set these charges separately based on the responding advice the QCA provided to me on 13 September 2019.

The government is committed to customers in regional Queensland having more choice in electricity tariffs while maintaining the UTP. With this in mind, the government supports efforts by Ergon retail to develop new tariff structures in regional Queensland. In setting prices for 2020–21, I encourage the QCA to consult closely with retailers operating in regional Queensland, in particular regarding the continuation of existing standard tariffs. These consultations will also be key in the establishment of any new standard tariffs reflecting new network tariffs approved by the AER for the 2020–25 period.

You will note that the government has refined the definition of the UTP to clarify that it applies to the structure of retail tariffs, as well as the price level. This ensures customers are not treated differently because of where they live in Queensland.

Customers often do not nominate a tariff when they seek to establish an electricity account. To expedite account establishment in the interest of customers, Ergon retail generally assigns Tariff 11 for residential and Tariff 20 for small business customers as default tariffs when this occurs, reflecting current underlying network tariff assignment. However, it is likely that default network tariff assignment practices will change from 1 July 2020. Further clarification is provided to assist the QCA in its application of the UTP and maintain existing retail tariff assignment practices to avoid potential risks of adverse and unintended outcomes for customers in the first year of new network tariffs. The QCA should consider nominating Tariff 11 to be a default residential tariff and Tariff 20 a default small business tariff, to apply when a customer does not nominate a tariff when they seek to establish an electricity account. This default designation should not limit customers from selecting alternative tariffs they are eligible for if they choose to do so.

I note that timing of decisions made by the AER as part of its Queensland distribution determinations for the 2020–25 regulatory control period may present challenges to the QCA's usual regulated retail price determination timeframe. Some flexibility is provided in this delegation in terms of both timing and price setting methodology to manage this risk.

Recognising that some customers accessing obsolete legacy tariffs would face challenges adjusting to standard business tariffs, I extended the phase-out dates by one year to 1 July 2021. As these obsolete tariffs are not based on the actual costs of supplying electricity, the expiry date should be maintained and all customers on these tariffs will need to switch to a standard business tariff before 1 July 2021. I understand Ergon distribution is proposing to the AER new tariffs more suited to the needs of these customers, who will continue to be supported through the UTP.

Ergon distribution has also proposed to the AER to reassign some Connection Asset Customers (CAC) to Individually Calculated Customers (ICC) in 2020-21 when they have been identified as an outlier to their costs to serve. This has the potential to significantly lower the network charges for some of these customers. The government considers it important that any potential reduction in network charges be passed through to customers via notified prices. However, to ensure existing ICC customers are no worse off, the QCA should also maintain Tariff 53.

Public consultation is a vital part of the QCA's process for determining retail electricity prices. In this regard, the terms of reference requires that the draft determination should be issued in February 2020, but not later than the end of March 2020, with public consultation to follow, and a final determination should be delivered by 31 May 2020, but not later than 26 June 2020.

The government is committed to delivering lower electricity bills. My department will consult with the QCA on specific wording for the 2020–21 gazette, ensuring regional customers continue to benefit from the electricity cost protection provided by the UTP.

If you have any questions, [redacted] Executive Director, Consumer Strategy and Innovation, Department of Natural Resources, Mines and Energy will be pleased to assist you and can be contacted on telephone [redacted]

Yours sincerely

Dr Anthony Lynham MP
Minister for Natural Resources, Mines and Energy

Att

[redacted] **DELEGATION TO QCA**

DEPARTMENT OF NATURAL RESOURCES, MINES AND ENERGY

Electricity Act 1994

ELECTRICITY (MINISTERIAL – QCA) DELEGATION (NO. 1) 2019

Power to delegate

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

Powers delegated

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

3. The functions of the Minister specified in paragraph 2 above must only be exercised for the purpose of deciding the prices, or the methodology for fixing the prices, for the tariff year 1 July 2020 to 30 June 2021 that a retail entity may charge its Standard Contract Customers in Queensland, other than:
   (a) Standard Contract Customers in the Energex distribution area; and
   (b) notified prices for retail metering services for residential and small business customers.

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

Revocation

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

6. Unless earlier revoked in writing, this delegation ceases upon gazettal by the QCA of its final price determination on regulated retail electricity tariffs for the 2020–21 tariff year under section 90AB of the Act.

This delegation is made by **The Honourable Anthony Lynham MP**, Minister for Natural Resources, Mines and Energy:

Signed:

The Honourable Anthony Lynham MP
Minister for Natural Resources, Mines and Energy

Dated: 9/12/19

[redacted] 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 2020 to 30 June 2021.

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

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

   (a) On 1 July 2016, price regulation in the Energex distribution area was removed for small customers. This means that notified prices do not apply to customers in the Energex distribution area;

   (b) 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 pay for their electricity via similar price structures, regardless of their geographic location. However, as residential and small business customers paying notified prices are on standard retail contracts, the Government is of the view that the QCA must consider incorporating into notified prices, an appropriate value reflecting the more favourable terms and conditions of standard retail contracts compared to market contracts. Should the application of this value result in a bill that exceeds the equivalent Default Market Offer as set by the Australian Energy Regulator for southeast Queensland, that value should be discounted so that the resulting bill does not exceed the equivalent Default Market Offer;

   (c) Default tariffs – 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;

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

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

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

(ii) For all other residential and small business customer tariffs - basing the network cost component on the price level of the relevant Energex network charges to be levied by Energex, but utilising the relevant EECL tariff structures, in order to strengthen or enhance the underlying network price signals and encourage customers to switch to time-of-use and demand tariffs and reduce their energy consumption during peak times;

(iii) For large business customers who consume 100MWh or more per annum - basing the network cost component on the relevant EECL network charges to be levied by EECL;

(iv) For Individually Calculated Customers (ICC), consider a methodology that allows for the pass through of the customers' individual network charges;

(v) For all existing Standard tariffs as set out in Part 2 of the current Tariff Schedule – maintaining these tariffs including price structures and access criteria unless otherwise set out in this delegation, and for those that do not have a network tariff of similar price structure and access requirements in the tariff year, or existing applicable network tariff structures are altered or extinguished - basing the network cost component on the most suitable network tariff consistent with e(i), (ii) and (iii) above;

(vi) In the event of significant uncertainty of both the prices and price structures of network tariffs to apply during the tariff year, and the QCA determines that there is insufficient time for the determination of the N component as set out in (e)(i), (ii) and (iii) above, use of a price indexation methodology to determine the N component for all existing Standard tariffs as set out in Part 2 of the current Tariff Schedule;

(f) Transitional Arrangements – maintaining the current phase-out dates of obsolete tariffs (i.e. Tariffs 20 (large), 21, 22 (small and large), 37, 47, 48, 62, 65, and 66);

(g) 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;

(h) Continuing Ergon Energy Queensland Pty Ltd's EasyPay Reward 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 (except for pricing for ICC determined under 2.(e)(iv) above) 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.

[redacted] DELEGATION TO QCA

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 (except for pricing for ICC determined under 2.(e)(iv) above) to be presented as bundled prices appropriate to the retail tariff structure, and gazette the retail tariffs.

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 2020–21 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, and this should occur in February 2020, but not later than March 2020.

15. The QCA must publish the final price determination on regulated retail electricity tariffs for the 2020–21 tariff year, and it should have the retail tariffs gazetted by 31 May 2020, but not later than 26 June 2020.

(SCHEDULE ENDS)

APPENDIX B: SUBMISSIONS AND REFERENCES

Submissions

We received 21 submissions over the course of this review. These are available on our website.[1]

Stakeholder	*Abbreviated form*	*Sub number*	*Date received*
Australian Sugar Milling Council	ASMC	1	13 Jan 2020
Bundaberg Regional Irrigators Group	BRIG	10	13 May 2020
Canegrowers	Canegrowers	2 11	3 Feb 2020 15 May 2020
COTA Queensland	COTA	12	15 May 2020
Cotton Australia	Cotton Australia	3 13	13 Jan 2020 13 May 2020
Energy Queensland	EQ	4 14	13 Jan 2020 13 May 2020
Kalamia Cane Growers Organisation	Kalamia	5 15	13 Jan 2020 13 May 2020
Mainstream Aquaculture Queensland	Mainstream Aquaculture	16	13 May 2020
National Seniors Australia	NSA	6	13 Jan 2020
Pioneer Valley Water Co-operative	PV Water	17	5 May 2020
Queensland Council of Social Services	QCOSS	7 18	13 Jan 2020 12 May 2020
Queensland Consumers' Association	Queensland Consumers' Association	8 19	13 Jan 2020 13 May 2020
Queensland Electricity Users Network	QEUN	20	15 May 2020
Queensland Farmers' Federation	QFF	9 21	13 Jan 2020 13 May 2020

References

ACIL Allen Consulting (ACIL Allen), *Estimated Energy Costs 2020–21 Retail Tariffs*, draft report prepared for the QCA, February 2020.

——*Estimated Energy Costs 2020–21 Retail Tariffs*, final report prepared for the QCA, June 2020.

Australian Energy Market Commission (AEMC), *Advice on Best Practice Retail Price Regulation Methodology*, final report, September 2013.

Australian Energy Market Operator (AEMO), 2019–20 *Electricity Final Budget and Fees*, June 2019.

[1] We received two confidential submissions, which are not available on our website.

——*2019 Electricity Statement of Opportunities*, August 2019.

——*Draft 2020 Integrated System Plan*, December 2019.

Australian Energy Regulator (AER), *Powerlink Transmission Determination 2017–18 to 2021–22*, final decision, April 2017.

——*Energex Distribution Determination 2020 to 2025*, draft decision, October 2019.

——*Ergon Energy Distribution Determination 2020 to 2025*, draft decision, October 2019.

——*Default Market Offer Prices 2020–21*, draft determination, February 2020.

——*Default Market Offer Prices 2020–21,* final determination, April 2020.

——*Ergon Energy Distribution Determination 2020 to 2025—Overview,* final decision, June 2020.

——*Ergon Energy Distribution Determination 2020 to 2025—Amended Tariff Structure Statement*, final decision, June 2020.

——*Energex Distribution Determination 2020 to 2025—Overview*, final decision, June 2020.

Energex, *Tariff Structure Statement 2020–25*, June 2019.

——*Tariff Structure Statement—Explanatory Notes 2020–25*, June 2019.

——*Revised Tariff Structure Statement 2020–25*, December 2019.

——*Revised Tariff Structure Statement—Explanatory Notes 2020–25*, December 2019.

Ergon Energy, *Tariff Structure Statement 2020–25*, June 2019.

——*Tariff Structure Statement—Explanatory Notes 2020–25*, June 2019.

——*Revised Tariff Structure Statement 2020–25*, December 2019.

——*Revised Tariff Structure Statement—Explanatory Notes 2020–25*, December 2019.

——*Tariff Structure Statement 2020–25,* May 2020.

Queensland Government, *Queensland Budget 2019–20—Budget Strategy and Outlook: Budget Paper No. 2*, June 2019.

Reserve Bank of Australia (RBA) 2020, *Statement on Monetary Policy—May 2020*, May 2020.

Yarrow, G, *Report on the impact of maintaining price regulation*, Regulatory Policy Institute, Oxford, UK, January 2008.

APPENDIX C: NETWORK COST APPROACH (SMALL CUSTOMERS)

This appendix provides further detail on how network costs[2] are estimated for the non-flat-rate tariffs of small customers (i.e. tariffs 12A, 14, 22A and 24) under a price indexation approach—specifically an 'X-factor' approach.[3] This approach allows for the pass-through of changes in network costs (as determined by the AER).To apply this approach, the 2019–20 network costs are adjusted using the AER's nominal X-factors.

The AER determines five X-factors for the purposes of revenue smoothing—the X-factor for the first year is also known as P_0. These X-factors indicate the changes in allowable annual cost/revenue (in real terms) of the distribution and transmission businesses.

To convert the X-factors from real to nominal terms, we have used the AER's X-factors, the CPI and the $CPI\ minus\ X$ price formula:

- for distribution charges, we used the 2020–21 Energex[4] specific CPI of 1.9 per cent and X-factor of –14.9 per cent, resulting in a nominal X-factor of –13.0 per cent[5]
- for transmission charges, we used the 2020–21 Powerlink specific CPI of 2.45 per cent and X-factor of 0.15 per cent, resulting in a nominal X-factor of 2.3 per cent.[6]

If we were to apply an X-factor approach to estimate the network costs of flat-rate tariffs, we would simply apply the nominal X-factors to the relevant 2019–20 network tariff component (i.e. apply a 13 per cent reduction to distribution network charges, and a 2.3 per cent increase to transmissions charges).

However, the application of the X-factor approach to estimate network costs for non-flat-rate tariffs is more complex, because the composition of the 2019–20 network charges for these tariffs (in terms of distribution and transmission charges) is unknown. This is because we determined the 2019–20 network charges (in our 2019–20 determination) to make them consistent with the UTP. We did this by reducing the Ergon Distribution network charges to Energex levels, while maintaining the Ergon Distribution tariff structures.

Therefore, we used the composition of the relevant Ergon network tariff to calculate the proportion of distribution/transmission charges as a share of network charges. By using the relevant proportions, we broke down the 2019–20 network charges into distribution and transmission charges before applying the relevant X-factors to estimate the 2020–21 network costs.

The tables below illustrate how the X-factor approach was applied to estimate network costs for the residential time-of-use tariff (retail tariff 12A).

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[2] For the purposes of this report, 'network cost/price' is a general reference to distribution and transmission costs/prices, unless otherwise indicated.

[3] This is discussed in section 4.1 of the final determination.

[4] Our final decision is to base notified prices for small customers on the costs of supply in SEQ. This means that network costs for small customers are based on Energex's costs.

[5] These figures are provided in the AER's final decision. The reduction in Energex's revenue is mainly due to a lower return on capital and decrease in allowance for tax/revenue adjustments. See AER, *Energex Distribution Determination 2020 to 2025—Overview*, final decision, June 2020.

[6] The reduction in Powerlink's revenue is primarily driven by a lower return on capital. See AER, *Powerlink Transmission Determination 2017–18 to 2021–22,* final decision, April 2017.

Table 1 Breakdown of 2019–20 network costs (tariff 12A)

Charging parameter		***A***	***B***	***C***	***D***	***E***
		2019–20 Ergon network tariff		***2019–20 network costs***	***Breakdown of 2019–20 network costs***	
		Share of network charges				
		Distribution	***Transmission***		***Distribution***	***Transmission***
Fixed		92.6%	7.4%	37.258 c/day	34.498 c/day	2.760 c/day
Usage	Peak	97.5%	2.5%	41.467 c/kWh	40.443 c/kWh	1.024 c/kWh
	Off-peak	80.2%	19.8%	5.182 c/kWh	4.158 c/kWh	1.024 c/kWh

Note: Totals may not add up precisely due to rounding. For this calculation, the network costs are the sum of distribution and transmission costs. The relevant Ergon network tariff for retail tariff 12A is ERTOUT1. The distribution costs were estimated using the formula: $D = A \times C$, *while the transmission costs were estimated using the formula:* $E = B \times C$.

Source: Our analysis using data from Energy Queensland.

Table 2 Application of X-factor approach (tariff 12A)

Type	***A***	***B***	***C***	***D***	***E***	***F***	***G***
	2019–20			***AER's nominal X-factor***	***2020–21***		
	Fixed (c/day)	***Usage (c/kWh)***			***Fixed (c/day)***	***Usage (c/kWh)***	
		Peak	***Off-peak***			***Peak***	***Off-peak***
Distribution	34.498	40.443	4.158	–13.0%	30.013	35.185	3.617
Transmission	2.760	1.024	1.024	2.3%	2.823	1.047	1.047
Total network	37.258	41.467	5.182	–	32.837	36.232	4.665

Note: Totals may not add up precisely due to rounding. The 2020-21 fixed charges were estimated using the formula: $E = A \times (1 + D)$, *the peak usage charges were estimated using the formula:* $F = B \times (1 + D)$ *and the off-peak usage charges were estimated using the formula:* $G = C \times (1 + D)$ *For this calculation, the total network charges are the sum of distribution and transmission charges.*

Source: Our analysis using data from the AER and Energy Queensland.

APPENDIX D: JURISDICTIONAL SCHEME CHARGES

The jurisdictional scheme charges in the table below are included in the network component of notified prices. These charges are taken from Energex's and Ergon Energy's annual pricing proposal for 2020—21 submitted to the AER (26 May 2020).

Table 3 Jurisdictional scheme charges included in 2020–21 notified prices (GST exclusive)

Tariff class	***Retail tariff***	***Fixed (c/day)***	***Usage (c/kWh)***
Residential	11, 12A, 14	1.100	0.932
Small business	20, 22A, 14, 41	1.100	0.993
Controlled load	31, 33	-	0.812
Unmetered	91	-	0.659
Large business	44, 45, 46 ,50	52.100	0.064
Very large business	51A—51D, 52A–52C, 53	1065.700	0.051

Source: Energy Queensland.

EQ's advice to the QCA on Jurisdictional Scheme amounts (February 2020)

Energy Queensland

21 February 2020

Mr Charles Millsteed
Chief Executive Officer
Queensland Competition Authority
GPO Box 2257
Brisbane QLD 4001

Dear Mr Millsteed

Indicative Rates inclusive of Jurisdictional Scheme amounts: 2020-25

As you are aware, Energex and Ergon Energy did not include Jurisdictional Scheme amounts in the Revised Tariff Structure Statements submitted to the Australian Energy Regulator (AER) on 10 December 2019.

We have attached the Indicative Pricing Schedules for Energex and Ergon Energy Network which include Jurisdictional Scheme values where required. This is the information that Energex and Ergon Energy are preparing to include in their Annual Pricing Proposals, due to the AER in mid-May 2020 and which take effect from 1 July 2020. As that is the first opportunity for Energex and Ergon Energy to formally advise the AER of 2020-21 Jurisdictional Scheme rates, the attached Pricing Schedules are provided to the QCA noting that these may change.

Please note that an update of all input revenues (including Solar Bonus Scheme and Australian Energy Market Commission Levy) will be undertaken in the preparation of the Annual Pricing Proposals. This is likely to change the Jurisdictional Scheme rates included in the attached Indicative Pricing Schedules by a small amount.

Please contact me should you wish to discuss.

Yours sincerely

Karen Stafford
General Manager, Legal, Regulation and Pricing

APPENDIX E: ENERGY COST APPROACH

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

ACIL Allen's final report, including the information we relied on to prepare this technical appendix, is available on our website.[7]

Wholesale energy costs

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) to meet the demand of its customers. The NEM is a volatile market where spot prices are settled every half-hour and currently can range from –$1,000 to $14,700 per megawatt hour (MWh).[8]

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

- pursuing a hedging strategy by purchasing financial derivatives[9]—such as futures, swaps, caps and options
- entering long-term power purchase agreements with generators
- investing in their own electricity generators.

For the 2020–21 determination, we engaged ACIL Allen to assist with estimating wholesale energy costs for customers whose prices are settled on:

- the net system load profiles (NSLPs) in the Energex and Ergon distribution areas
- the controlled load profiles (CLPs) in the Energex distribution area.

The NSLP and CLP approximate how much electricity is consumed by customers on accumulation meters in a region, for each half-hour of the day. Unlike smart/interval meters, accumulation meters do not record when during the day electricity was consumed or how much was consumed at that time. To allow for half-hourly settlement within the NEM (with different spot prices and volume for each half hour), the Australian Energy Market Operator (AEMO) uses the NSLP to approximate the amount of electricity consumed by customers on accumulation meters in a region, for each half hour of the day.

At this stage, most customers in Queensland are on accumulation meters. There are currently two types of CLPs in the Energex distribution area—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.

We have also requested ACIL Allen to investigate the feasibility of estimating wholesale energy costs for the new controlled load network tariffs that Energy Queensland proposed in its 2020–25 Tariff Structure Statement.[10]

[7] ACIL Allen, *Estimated Energy Costs 2020–21 Retail Tariffs*, final report prepared for the QCA, June 2020.

[8] 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.

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

[10] Energex, *Revised Tariff Structure Statement 2020–25*, December 2019; Ergon Energy, *Revised Tariff Structure Statement 2020–25*, December 2019.

Summary of analysis and findings

Consistent with previous years, ACIL Allen has estimated wholesale energy costs using a market hedging approach. This approach is designed to simulate the NEM from a retailer's perspective. More specifically, it involves:

- simulating the expected spot prices that a retailer faces, considering temperature data, demand load profiles, generation supply/costs and power station availability,
- then estimating wholesale energy costs for a retailer that hedges spot price risk through the purchase of ASX Energy futures[11].

Compared to the estimates for the 2019–20 price determination, ACIL Allen estimated that wholesale energy costs for 2020–21 will:

- **decrease** for customers, whose prices are settled on the **Energex NSLP** and **Energex CLP 9100**. This decrease reflects a decline in the trade-weighted ASX contract prices[12] largely due to market expectations aligning with softening of spot prices—driven by the continued entry of large amount of renewable generation into the NEM and a reduction in domestic gas prices. The reduction in domestic gas prices is due to a slightly better global supply outlook, which has meant LNG exporters have made more supply available to the domestic market due to depressed international prices
- **decrease** for customers, whose prices are settled on the **Ergon NSLP**. Reductions in wholesale energy costs for the Ergon NSLP are less significant—compared with the Energex NSLP—due to the projected increase in the uptake of rooftop solar PV in the Ergon area, which reduces the electricity consumed from the grid during non-peak periods (i.e. daylight hours). Such a development puts upward pressure on the wholesale energy costs for the Ergon NSLP, because a greater proportion of the electricity from the grid is consumed during peak periods[13]
- **decrease marginally** for customers, whose prices are settled on the **Energex CLP 9000**. This small decrease is primarily driven by the load requirement and pattern of the Energex CLP 9000 (controlled by Energex).[14] About 65 per cent of the load requirements for the Energex CLP 9000 occurs between 10 pm and 2 am. ACIL Allen's modelling estimated that wholesale prices during these periods are not decreasing, given that the entry of substantial utility-scale solar generation is unlikely to put downward pressure on prices during these periods.

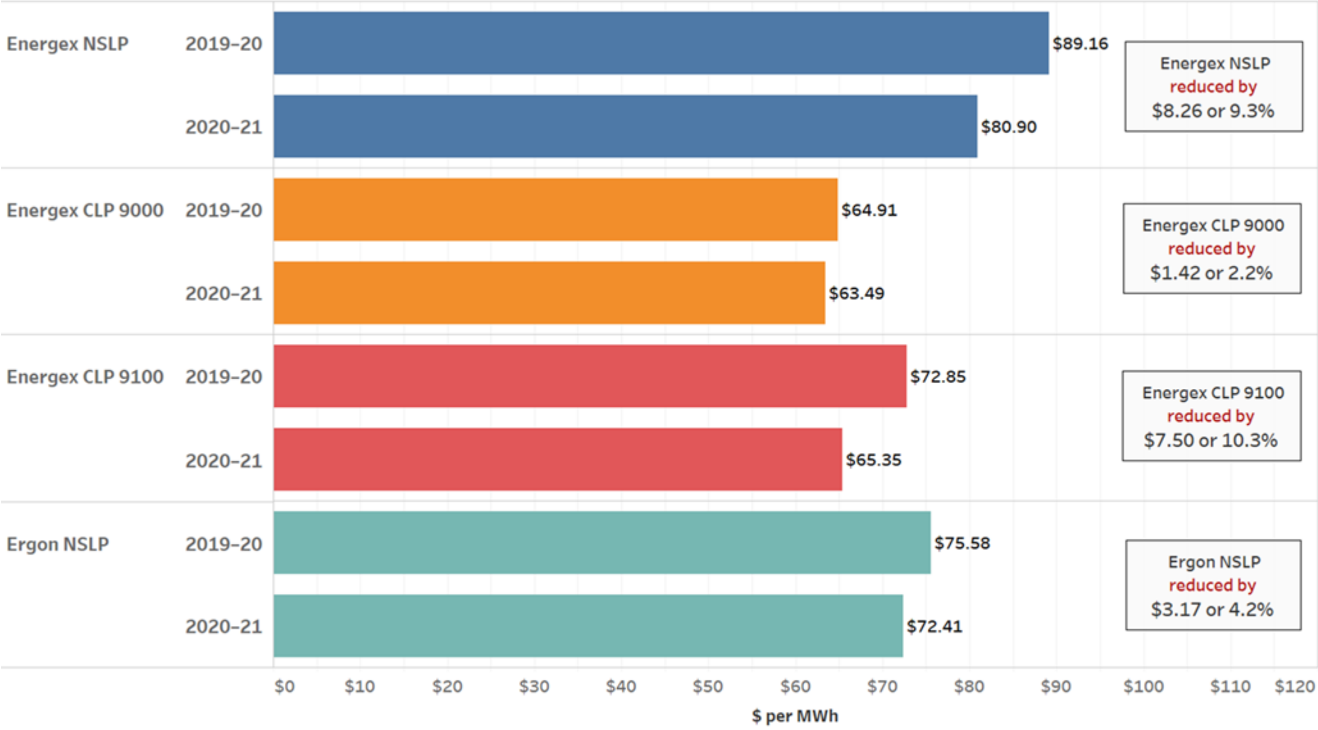
[11] ASX energy futures are exchange-traded energy financial derivatives, which allow retailers to reduce the spot price volatility risk when purchasing electricity from the NEM. For more information, see https://www.asxenergy.com.au/.

[12] Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for 2020–21.

[13] ACIL Allen projects a continued uptake of rooftop solar PV in the Energex area too. However, given the historically and comparatively stronger uptake of rooftop solar PV in the Energex area, the projected future uptake does not change the load shape of the NSLP as severely as that of the NSLP in the Ergon area.

[14] The load requirement and pattern of the Energex CLP 9000 are controlled by Energex through the management of its network tariff—NTC 9000 Super Economy. Under this network tariff, Energex ensures that the supply of electricity is available for a minimum of eight hours per day. Energex manages the load for this network tariff such that it maintains customer comfort, maximises utilisation and minimises peak demand on the Energex network.

Figure 1 Wholesale energy costs by settlement class



Source: Our analysis using data from ACIL Allen.

Spot prices—demand profiles and historical energy cost levels

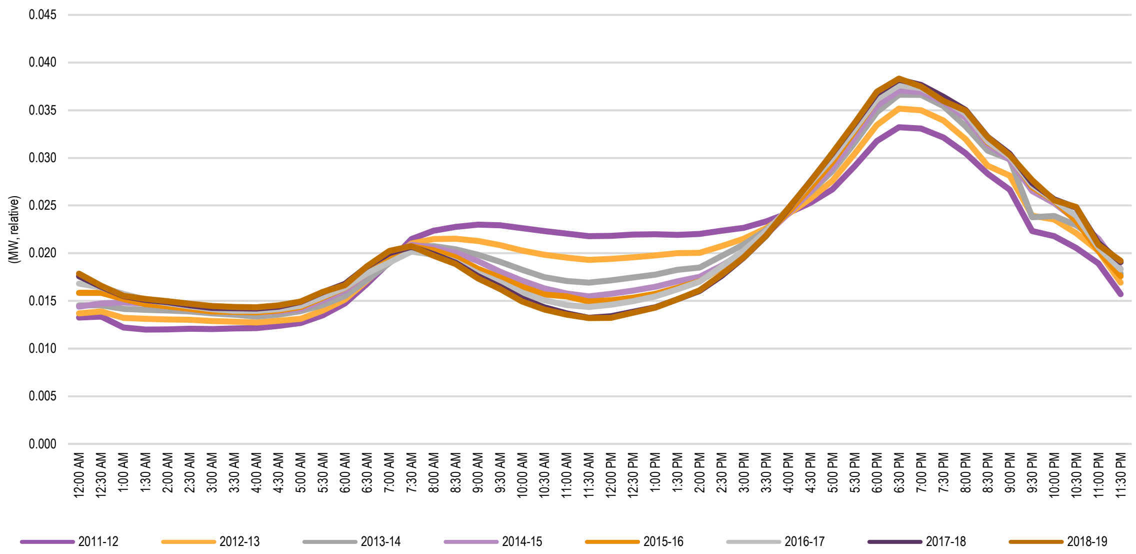
To simulate expected spot prices, ACIL Allen used its stochastic demand model to develop 49 weather-influenced simulations of hourly demand for 2020–21—using temperature data from 1970–71 to 2018–19 and demand load profiles from 2016–17 and 2018–19.

The historical demand load profiles were sourced from AEMO. When simulating the weather-influenced hourly demand, ACIL Allen also incorporated AEMO's latest peak demand forecast for 2020–21.[15] This section provides an overview of the demand profiles that ACIL Allen used for its analysis. More details are available in chapter 4 of ACIL Allen's final report.

Over the past few years, the Energex and Ergon NSLPs have become 'peakier', due to increased penetration of rooftop solar PV, which has reduced daytime demand but has had limited effect on the evening peak demand (see figures below). The Energex NSLP has the highest proportion of electricity from the grid consumed during peak periods relative to other demand profiles. Consequently, it has the highest wholesale energy costs of the profiles analysed in Queensland. The Ergon NSLP is less 'peaky' than the Energex NSLP, largely due to a slightly slower uptake of rooftop solar PV, and consequently, it has lower wholesale energy costs.

[15] AEMO, *2019 Electricity Statement of Opportunities*, August 2019.

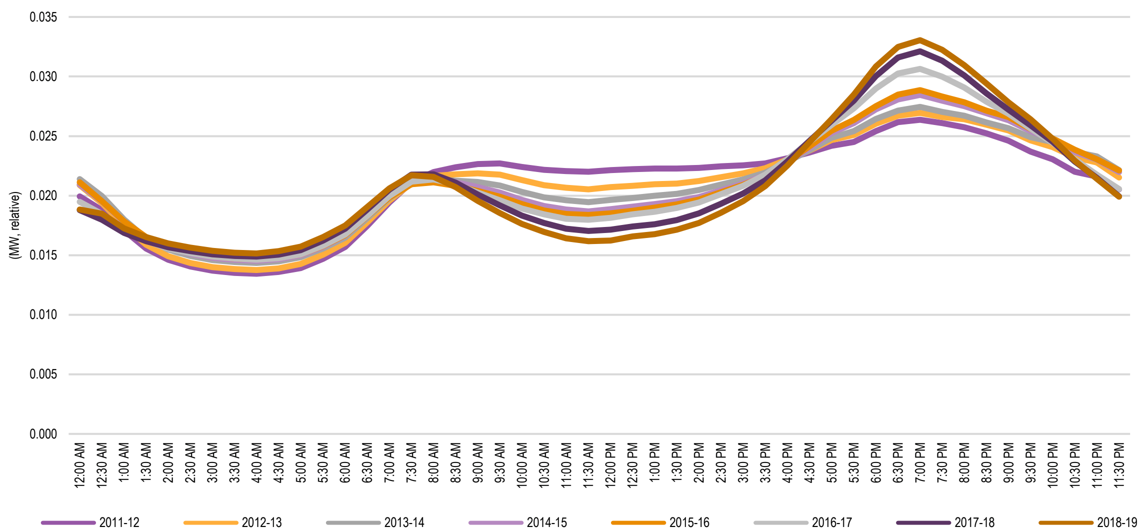
Figure 2 Energex NSLP



Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs 2020–21 Retail Tariffs, June 2020.

Figure 3 Ergon NSLP

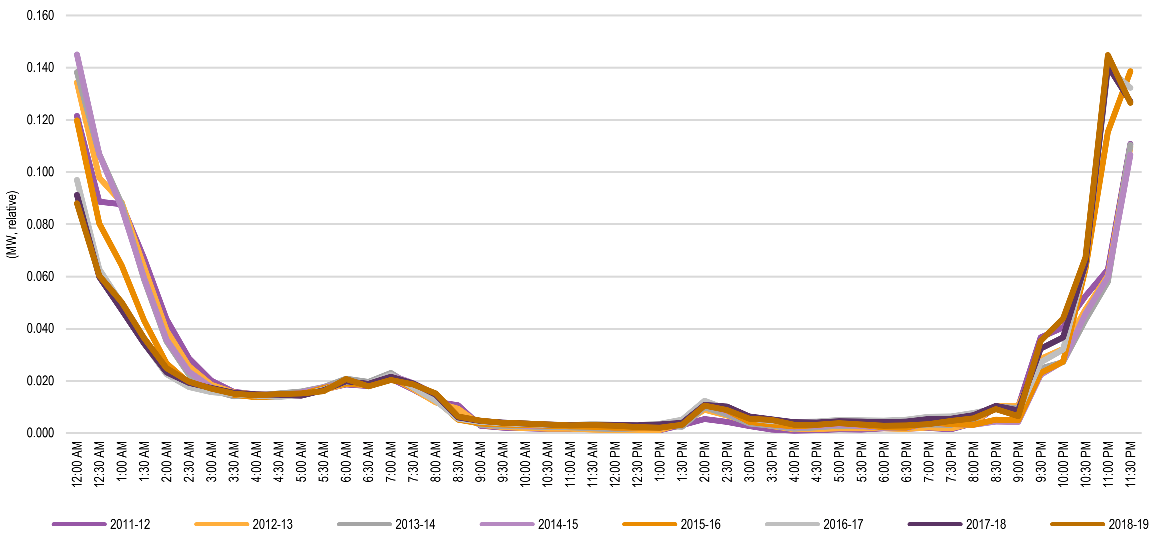


Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs 2020–21 Retail Tariffs, June 2020.

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 (see the figures below). 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 relatively more electricity consumed during daylight hours and the evening peak than the latter.

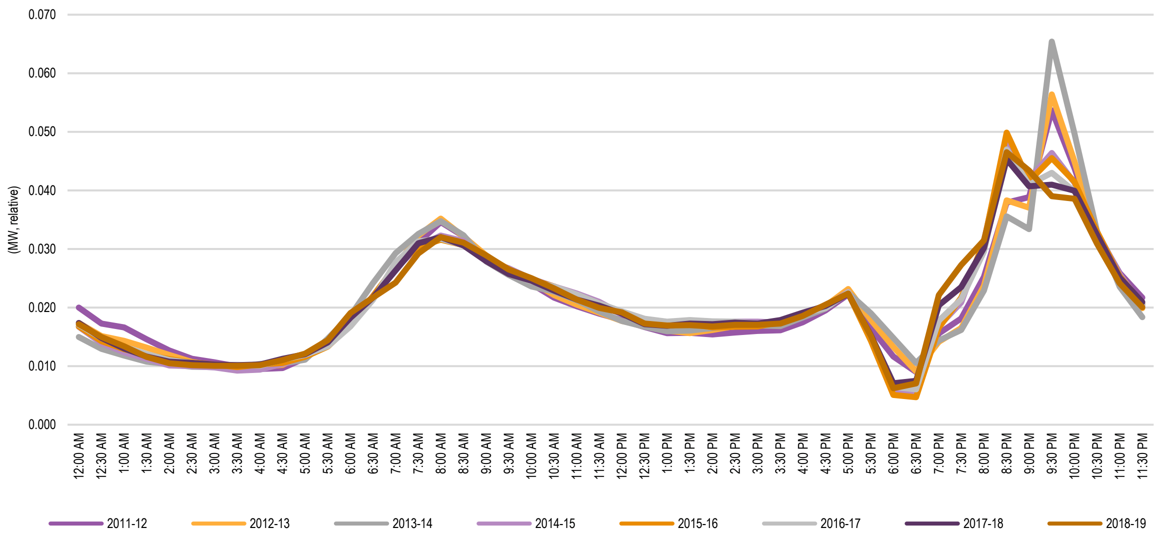
Figure 4 Energex CLP 9000 (retail tariff 31)



Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs 2020–21 Retail Tariffs, June 2020.

Figure 5 Energex CLP 9100 (retail tariff 33)



Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, Estimated Energy Costs 2020–21 Retail Tariffs, June 2020.

Spot prices—generation supply and cost forecasts

In addition to the 49 simulated demand profiles, ACIL Allen used its stochastic outage model to develop 11 hourly power station availability simulations. ACIL Allen then applied its proprietary electricity model (PowerMark) to generate 539 simulations of 8760 hourly wholesale electricity spot prices for 2020–21, using the stochastic demand profiles and power station availabilities as inputs.

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

ACIL Allen's forecast of the generation supply and costs within the NEM closely aligns with AEMO's latest Integrated System Plan (ISP).[16] The ISP was developed to provide technical/market data that informs the decision-making processes of interested parties as they operate/invest in the NEM.

ACIL Allen's modelling also includes the formation of CleanCo.[17] CleanCo's portfolio includes the Wivenhoe pumped storage facility, the Swanbank E gas power station, Barron Gorge, Kareeya and Koombooloomba hydro stations. The key impact of CleanCo is the change in operation of Wivenhoe. As part of CleanCo (a small generation portfolio), Wivenhoe is operated more aggressively, where it ramps up during periods of high spot prices. This would likely place downward pressure on peak prices.

ACIL Allen advised that its wholesale spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX futures) for 2020–21. More details are available in chapters 2 and 4 of ACIL Allen's final report.

Hedged energy costs—hedging methodology and contract prices

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

Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for 2020–21. To calculate the trade-weighted futures contract prices, ACIL Allen has used the contract prices and volume of contracts traded until 8 May 2020.

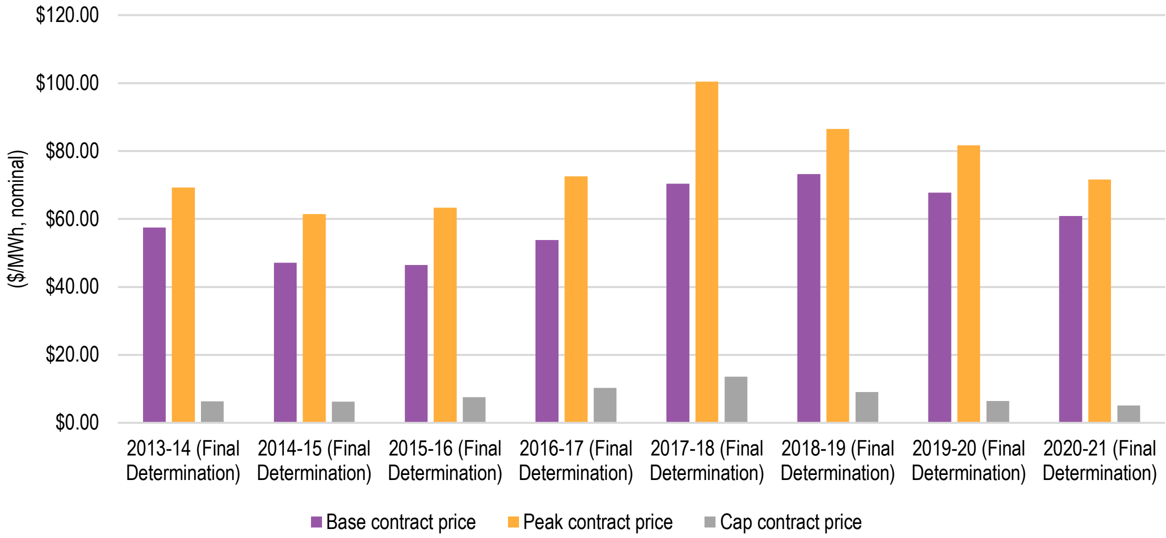
Compared to the contract prices estimated for the 2019–20 final determination, futures contract prices for 2020–21, on an annualised and trade-weighted basis, have:

- decreased by about $6.90/MWh for base contracts
- decreased by about $10.10/MWh for peak contracts
- decreased by about $1.40/MWh for cap contracts.

[16] AEMO, *Draft 2020 Integrated System Plan*, December 2019.

[17] In 2019, the Queensland Government restructured its government-owned generators and established a separate entity, CleanCo, to operate its existing renewable energy generation assets and develop new renewable energy projects.

Figure 6 Annualised quarterly electricity futures contract prices ($/MWh)



Source: ACIL Allen, Estimated Energy Costs 2020–21 Retail Tariffs, June 2020.

This reflects market participants expecting some softening in spot price outcomes due to the large amount of renewable generation expected to enter service. Approximately 5200 MW of new utility-scale solar and wind generation is expected to enter the NEM. Of the 5200 MW new capacity, 1350 MW is committed to enter the Queensland market.

Another driver of lower contract prices for 2020–21 is the reduction of domestic gas prices for gas-fired generation of electricity. Spot gas prices for the Australian east coast market have declined in the past 12 months from levels often above $10 per gigajoule. This reduction in gas prices is due to a slightly better global supply outlook, which has meant LNG exporters have made more supply available to the domestic market due to depressed international prices.

It is noted that cap contract prices, on a trade weighted basis, have decreased marginally between 2019–20 and 2020–21, which suggests that market participants are not expecting the large amount of additional renewable capacity to increase price volatility, despite the intermittent nature of renewable generation.

By applying the hedging methodology together with the simulated spot prices, ACIL Allen has derived 539 annual hedged energy costs for a given NSLP. ACIL Allen has taken the 95th percentile of this distribution of hedged costs as the final estimate of the wholesale energy costs.

Covid-19

In estimating wholesale energy costs, ACIL Allen considered that its existing methodology adequately captures any potential impacts of covid-19. It noted that, at this stage, it was not possible to quantify the long-term impact of covid-19 on the NEM, as this would be a function of the policy responses by both state and federal governments, which remain uncertain. Further, ACIL Allen noted that there was little evidence to suggest that covid-19 policy responses to date had a substantial impact on demand in the NEM. This may be due to a shift in electricity consumption from workplaces to homes and the closures or reductions in business operations limited to services with low electricity intensity.

ACIL Allen noted that its current methodology already captures the markets expectations of any impacts of covid-19 on the NEM, through the incorporation of ASX futures contracts up till 8 May 2020. More information regarding ACIL Allen's consideration of covid-19 can be found in chapters 2 and 3 of its final report.

Wholesale energy costs for new controlled load network tariffs

Energy Queensland has proposed new controlled load network tariffs for 2020–25 in its latest Tariff Structure Statements (TSSs)[18]:

- In the Energex area, it proposed a controlled load tariff for small business customers. Typical applications of this tariff are expected to be single large loads such as irrigation pumps and motors.
- In the Ergon area, it proposed controlled load tariffs for large business customers. These tariffs are expected to be suitable for connections where the nature of the operation (i.e. size of equipment, connection type, suitability for load control, etc.) is similar/identical to those of small customers on controlled load tariffs.

Energy Queensland noted that the terms and conditions for these network tariffs will be set out in its pricing proposal (to be approved by the AER in late June 2020).

ACIL Allen advised that estimating wholesale energy costs for a given tariff needs to be based on observable demand load data. At this stage, no information is available on the shape of the load associated with these new network tariffs or how Energex and Ergon intend to manage these loads. Therefore, ACIL Allen considered that it is not possible to develop separate wholesale energy cost estimates for these new network tariffs at this stage.

Our consideration—wholesale energy costs

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

We consider that ACIL Allen's use of a market-based approach is appropriate for the task of estimating wholesale energy costs for the 2020–21 price determination. While other methods for estimating wholesale energy costs exist, notably a long-run marginal cost (LRMC) approach, we continue to be of the view 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 a LRMC approach are generally contained within confidential power purchase agreements (PPAs). Even if this information could be acquired, this would contribute to a reduced level of transparency in our analysis.

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

We also note that ACIL Allen's approach has generated a distribution of spot prices for 2020–21 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.

[18] Energex *(Revised Tariff Structure Statement 2020–25*, December 2019; *Revised Tariff Structure Statement—Explanatory Notes 2020–25,* December 2019); Ergon Energy (*Revised Tariff Structure Statement 2020–25*, December 2019; *Revised Tariff Structure Statement—Explanatory Notes 2020–25*, December 2019).

Furthermore, ACIL Allen's spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX futures) for 2020–21. Generally, the purchase of ASX futures enables retailers to lock in a price, or a maximum price (in the case of caps), at which a given volume of electricity will be transacted at a future date. Therefore, futures contract prices incorporate market participants' risk-weighted expectations of future spot prices.

To develop a hedging methodology, ACIL Allen tested a substantial number of strategies to derive a strategy with the lowest cost and variance. We consider such an approach to be appropriate as it is likely to reflect how a retailer would hedge in practice using ASX futures.

To estimate wholesale energy costs, ACIL Allen has taken the 95th percentile of the distribution of 539 annual hedged energy costs for a given NSLP. We consider this is a conservative estimate given there is only a 5 per cent probability that the final estimate underestimates the energy costs that retailers face in the NEM.

Covid-19

We consider that ACIL Allen's methodology has adequately taken into account the potential impacts of covid-19 on the NEM through the incorporation of ASX contract data until 8 May 2020. These contract prices reflect, to date, the market participants’ views of the impacts of covid-19, as well as other drivers, on the NEM. Additionally, to estimate wholesale energy costs, ACIL Allen’s methodology uses a large number of simulations (i.e. 539 simulations), which covers a wide range of demand outcomes. These demand outcomes are likely to adequately capture the volume risks[19] that retailers face.

Further, we consider ACIL Allen's decision to maintain its current demand forecasting methodology to be appropriate at this stage, given that:

- it is unclear to what degree the change in demand (since the covid-19 lock-down) can be attributed to the health policy response to covid-19
- more importantly, whether any observed change in demand will persist into 2020–21, considering that the extent and duration of the covid-19 restrictions remain unclear (both during the outbreak and the recovery period after the outbreak).

At this stage, since the lock-down, Queensland has experienced only moderate reduction in demand. In particular, AEMO reported a demand reduction (before accounting for temperature changes) of around 6 per cent during weekdays with smaller impacts on weekends during the first two weeks of April 2020.[20] However, these reductions are smaller than the declines observed in 2019, despite an average temperature reduction of a similar magnitude over the same period in both 2019 and 2020.[21]

Much greater reductions have been observed in parts of Europe and the US, where tighter covid-19 restrictions and full lock-down had been imposed. AEMO reported that demand reductions of 20 to 30 per cent were observed in those countries during periods of lock-down.[22]

Comparing wholesale spot prices with hedged energy costs

QEUN has heavily emphasised the declining wholesale spot prices since covid-19 restrictions were introduced and compared wholesale prices with our hedged energy cost estimates. However, wholesale prices do not reflect the costs that retailers would incur in practice when sourcing electricity from the NEM.

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

[20] See AEMO's website at https://aemo.com.au/en/news/demand-impact-australia-covid19.

[21] See ACIL Allen, *Estimated Energy Costs 2020–21 Retail Tariffs*, final report prepared for the QCA, June 2020.

[22] See AEMO's website at https://aemo.com.au/en/news/demand-impact-australia-covid19.

To manage spot price volatility risk, retailers generally lock-in the price in advance for an amount of electricity that they have to pay for in the future (for example, by hedging through the purchase of ASX contracts). In other words, retailers had already locked-in higher future electricity prices for a proportion of electricity to be supplied in 2020–21, before the more recent decline in wholesale and contract prices (that coincides with the covid-19 restrictions).

Considering the ASX contracts traded until 8 May 2020, approximately 90 per cent of these contracts were purchased before the covid-19 restrictions came into effect. In other words, retailers had already locked-in 90 per cent of their wholesale energy costs before the more recent decline in contract prices that coincides with the introduction of covid-19 restrictions. However, we note that this more recent decline is a continuation of a downward trend for ASX contract prices as prices have been declining since November/December 2019. Finally, since mid-May 2020, contract prices traded on ASX Energy have generally stabilised.

Negative spot price outcomes during daylight hours

We agree with EQ that the continued uptake of rooftop solar PV and development of utility scale solar PV will likely increase the number of negative spot price outcomes during daylight hours. However, this phenomenon is not something new. In our earlier determinations, there were occasions when the simulated spot prices were below their corresponding trade-weighted contract prices. That was typically during the 1 am to 4 am period (when demand was at its lowest) instead of during daylight hours. What has changed is the propensity for low spot price outcomes to occur and their timing, as periods with low prices are no longer constrained predominantly to periods between 1 am and 4 am.

For this determination, the simulated spot prices during daylight hours (an average of $40/MWh) tend to be below their corresponding trade-weighted contract prices (annualised base contact price of around $61/MWh). Therefore, retailers will be subject to negative contract for difference payments during these periods. These negative payments are accounted for by ACIL Allen's hedge model as a cost incurred by retailers when pursuing a hedging strategy using financial derivatives.

We are satisfied that ACIL Allen's methodology adequately addresses EQ's concerns and captures the impacts of negative spot price outcomes during daylight hours. Further, we consider that ACIL Allen's approach adequately captures the propensity of negative spot price occurring during daylight hours by using the latest data on solar generation when estimating wholesale energy costs.

Conclusion

To conclude, we consider ACIL Allen's market hedging approach:

- adequately takes into account the issues raised in submissions
- is transparent and likely to produce reliable estimates that best reflect the actual costs retailers incur when purchasing electricity from the NEM.

The Australian Energy Market Commission (AEMC) also endorsed such an approach in its 2013 advice on best practice retail regulation.[23]

We have also accepted ACIL Allen's advice on the matter of developing separate wholesale energy cost estimates for the new controlled load network tariffs (i.e. that it is not possible to develop separate estimates at this stage).

[23] AEMC, *Advice on Best Practice Retail Price Regulation Methodology*, final report, September 2013.

Other energy costs

In addition to 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.

Our decision is to estimate other energy costs based on ACIL Allen'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 33,850 GWh for 2020, and 33,000 GWh for 2021.[24]

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

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

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

ACIL Allen estimated that the LRET cost for 2020–21 will be $4.99/MWh for all retail tariffs—a reduction of $4.39/MWh compared to the 2019–20 final determination. This reduction is mainly due to lower expected LGC prices.

ACIL Allen's market-based approach to estimating LRET costs uses the latest data, where available and appropriate. We consider such an approach is likely to produce the most reliable and transparent estimate of LRET costs to be incurred by retailers in 2020–21. 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

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

- cost information necessary to accurately undertake a LRMC approach are generally contained within confidential PPAs. Even if this information could be acquired, this would contribute to a reduced level of transparency in our analysis.

Large-scale generation certificate prices

The expected LGC prices were estimated using LGC forward prices[25] provided by TFS Australia (an energy brokerage company). ACIL Allen has improved the way it estimates the expected LGC prices by using the trade-weighted average (rather than the simple average) of LGC forward prices for 2020 and 2021. This approach assumes that retailers build up their LGC coverage over a period of time to meet their obligations under the LRET scheme.

ACIL Allen estimated the expected LGC prices to be $31.75/MWh for 2020 and $19.82/MWh for 2021. LGC forward prices have fallen since they were last estimated for the 2019–20 final determination. This reflects the market's expectation of an increase in supply of LGC due to:

- a number of renewable energy projects reaching financial closure in recent months, with most of these projects expected to be commissioned during 2020
- a surge in renewable investment driven by decreasing costs in renewable generation, greater demand for renewable PPAs from corporate users and increased appetite of renewable investors to take on greater exposure to merchant risks[26].

ACIL Allen advised that the significantly lower average LGC forward prices for 2020 also reflect the market view that the LRET scheme is highly likely to be fully subscribed by 2020.

The LGC forward market is an active market consisting of several brokers and trading platforms. As such, it provides a sound basis for estimating the value of LGCs. We consider that LGC forward pricing is likely to be the most reliable indicator of the current market consensus view of LGC costs that retailers will face to meet their obligations under the LRET scheme. ACIL Allen's estimate of these forward prices using a trade-weighted average—rather than a simple average—of LGCs traded is appropriate, as it provides a more accurate representation of the LGC costs that retailers are likely to incur. Further, it aligns with our approach to estimating wholesale energy costs, where futures contract prices are estimated on a trade-weighted basis.

Renewable power percentage

As discussed, the RPP values dictate the number of LGCs that a retailer needs to purchase and surrender to the CER. The CER has determined the RPP for 2020 at 19.31 per cent in March 2020.

To estimate the RPP for 2021, ACIL Allen used the mandated LRET targets (published by the CER) and its estimates of electricity acquisitions for 2021. The RPP value was estimated by dividing the LRET target by the electricity acquisitions of liable entities. ACIL Allen's approach to calculating the RPP aligns with the CER's. The estimated RPPs for 2021 is 19.44 per cent.

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.

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[25] 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.

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

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

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

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

The SRES cost for 2020–21 is estimated to be $9.31/MWh for all retail tariffs—an increase of $2.05/MWh compared to the 2019–20 final determination. This substantial increase is mainly driven by higher STPs, which reflect a higher uptake in small-scale renewable energy systems than previously estimated.

To estimate SRES costs, ACIL Allen aligned its methodologies with the way retailers are likely to incur these costs in practice, taking into account CER's requirements and STC clearing house processes. We consider such an approach is likely to produce the most reliable estimate of SRES costs to be incurred by retailers in 2020–21.

Small-scale technology certificates price

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

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

Small-scale technology percentage

As discussed, the STP values dictate the number of STCs that retailers need to purchase and surrender to the CER. To estimate the STPs for the final determination, ACIL Allen has used the CER's binding STP of 24.4 per cent for 2020 and its own estimate of 22.15 per cent for 2021. The 2020 binding STP is much higher than the CER's earlier published non-binding estimate of 14.56, reflecting an uplift of 5.9 million STCs due to the carryover of surplus STCs from 2019.

For this final determination, ACIL Allen has opted to use its own forecast of the 2021 STP (produced in May 2020), rather than the CER's non-binding estimate (produced in January 2020).[27] We consider this to be appropriate as ACIL Allen's more recent forecast will capture the latest developments in the uptake of small-scale renewable energy systems. This is also consistent with the AER's approach to estimating the SRES costs in its recently released 2020–21 DMO final determination.

Given that the CER typically determines the final SRES liabilities for the second half of the financial year about 9 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.

[27] We note that ACIL Allen's estimate of the 2021 STP (22.15 per cent) is marginally higher than the CER's non-binding estimate (19.4 per cent).

NEM management fees

NEM management fees are levied by AEMO to cover its costs related to operating the NEM, performing its function as the National Transmission Planner, full retail contestability and the funding of Energy Consumers Australia. ACIL Allen estimated the NEM fees using the budget and projected fees in AEMO's report on its final budget and fees for 2019–20.[28]

ACIL Allen estimated that for 2020–21, NEM fees will be $0.71/MWh, an increase of $0.08/MWh, compared to the 2019–20 final determination. This increase primarily reflects the higher costs that AEMO expects to incur when managing the NEM. AEMO noted that increased complexities in managing the grid and the changing nature of generation meant that further investment will be required to manage the NEM.[29]

To estimate NEM fees, ACIL Allen aligned its methodologies with how retailers are likely to incur these costs in practice, taking into account AEMO's latest budget and projected fees. On this basis, we consider such an approach is likely to produce the most reliable estimate of NEM management fees to be incurred by retailers in 2020–21.

Ancillary services charges

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

ACIL Allen estimated the ancillary services charges using the average ancillary service payments[30] observed over the preceding 52 weeks.

For 2020–21, ancillary services charges were estimated to be $1.53/MWh, an increase of $1.16/MWh, compared to the 2019–20 final determination. This substantial increase is due to several events leading to a surge in demand for FCAS, including due to:

- the Basslink interconnector outage (August 2019 to October 2019)
- the planned outage of the Heywood to Mortlake line (September 2019)
- the 'islanding'[31] of the South Australian electricity grid due to an outage of the Heywood interconnector (November 2019)
- the extended power system separation between Victoria and South Australia (January to February 2020).

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

Prudential capital costs

Prudential capital costs are the costs that a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX in order to trade in futures contracts. ACIL Allen estimated prudential

[28] AEMO, *2019–20 Electricity Final Budget and Fees*, June 2019.
[29] AEMO, *2019–20 Electricity Final Budget and Fees*, June 2019.
[30] AEMO provides data on weekly settlements for ancillary service payments in each interconnected region within the NEM.
[31] Islanding occurs when a jurisdiction's electricity network is disconnected from the rest of the NEM.

capital costs in line with the latest published AEMO requirements and margin requirements for trading in the ASX futures market.

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

Prudential costs have fallen since the 2019–20 final determination, largely driven by lower expected price volatility in the NEM. ACIL Allen estimated the 2020–21 prudential costs to be $1.75/MWh for the Energex NSLP (and CLPs) and $1.43/MWh for the Ergon NSLP.

To estimate prudential costs, ACIL Allen has taken into account AEMO's prudential requirements and the ASX's margin requirements. We consider such an approach to be appropriate, as it aligns with how retailers incur these costs in practice and is likely to produce the most reliable estimates of prudential costs to be incurred by retailers in 2020–21.

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.

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

When estimating the AEMO prudential costs, ACIL Allen assumed that the retailer has no vertical integration (through generation ownership or PPAs) and does not engage in reallocation of prudential obligations. Reallocation is an AEMO procedure that allows counterparties to reduce their prudential obligations through instruments such as swaps or options. More details on ACIL Allen's approach are available in chapter 4 of its final report.

ACIL Allen estimated the 2020–21 AEMO prudential costs to be $0.46/MWh for the Energex NSLP (and CLPs) and $0.35/MWh for the Ergon NSLP.

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 Allen 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 which offsets some of the funding costs
- the ASX parameters which determine the initial margin—including the price scanning range, intra monthly spread charge and spot isolation rate for base, peak and cap contracts
- the annual average prices for base, peak and cap contracts
- the consumption profiles of the Energex and Ergon NSLP.

An additional margin may apply when contract prices move in an unfavourable manner for the buyer or seller of ASX contracts. However, ACIL Allen did not provide an allowance for an additional margin, as it is assumed that favourable and unfavourable movements in contract prices will cancel each other out over time. More details on ACIL Allen's approach are available in chapter 4 of its final report.

ACIL Allen estimated the 2020–21 hedge prudential costs to be $1.29/MWh for the Energex NSLP (and CLPs) and $1.08/MWh for the Ergon NSLP.

Reliability and Emergency Reserve Trader

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.

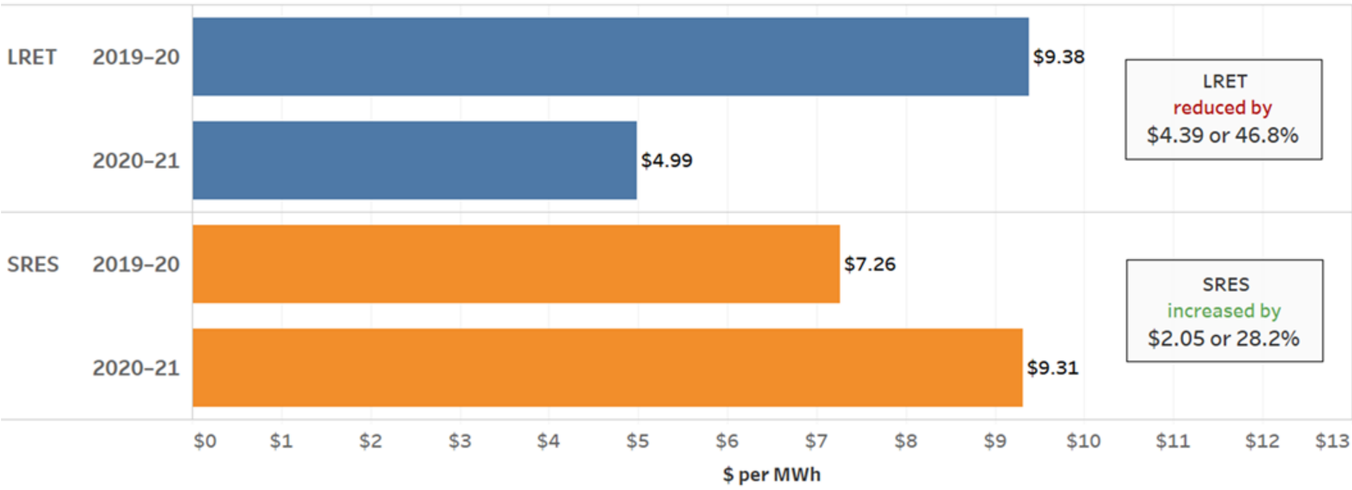
ACIL Allen considered it challenging to project these costs with a sufficient degree of accuracy. It noted that while it may be possible to project the RERT costs using its previous costs and AEMO's projection of unserved energy (USE)[32], there is currently insufficient data to do so.

Therefore, as with the ancillary services, ACIL Allen proposed to forecast the RERT costs using the costs published by AEMO for the 12-month period prior to 2020–21. At the time of our final decision, no RERT costs were incurred in Queensland for 2019–20. Therefore, for the 2020–21 determination, no RERT costs will be incorporated into notified prices.

We consider ACIL Allen's methodology to be appropriate given the highly uncertain nature of the RERT costs as 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 forecasted. The RERT scheme is only activated once all market options have been exhausted, generally during periods when the supply-demand balance is tight.

Summary of other energy costs

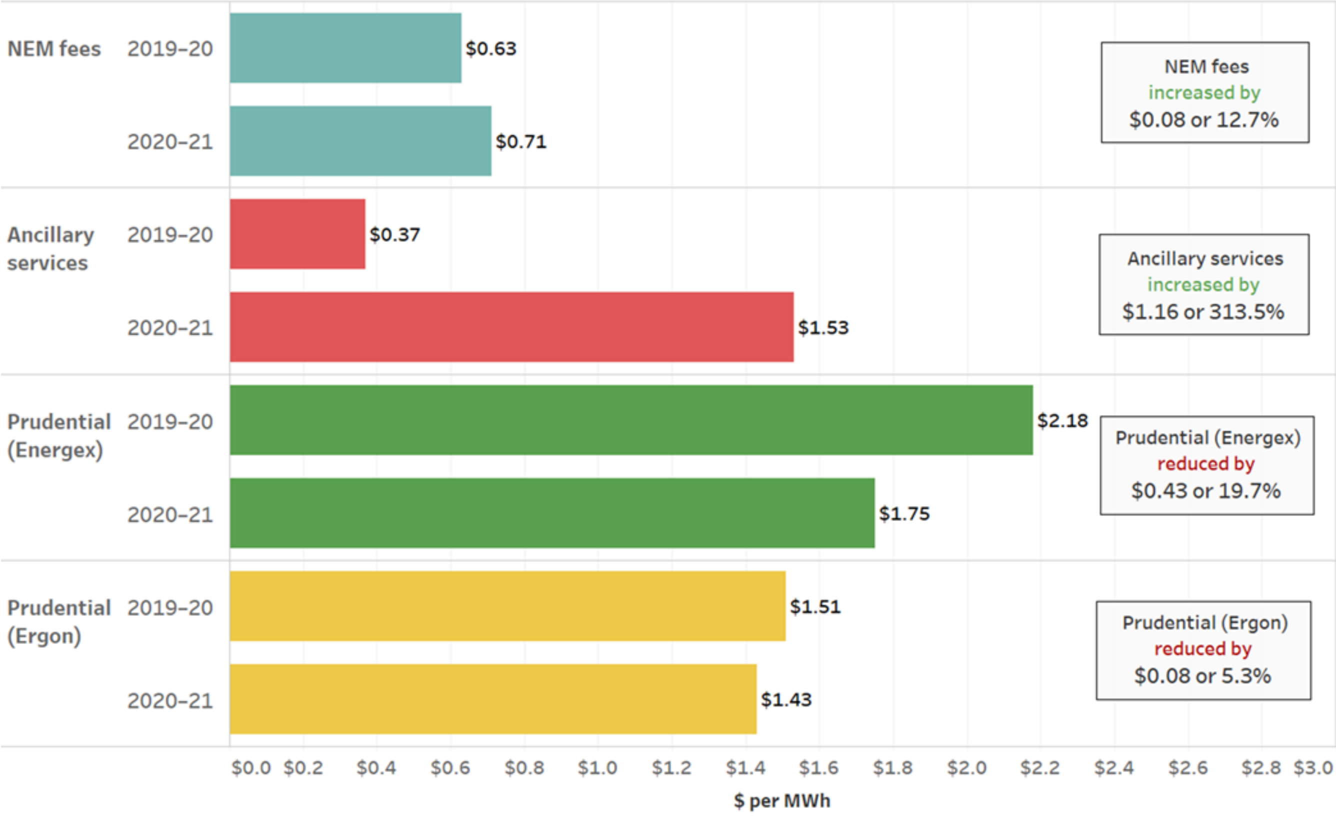
Figure 7 Other energy costs—LRET and SRES



Source: Our analysis using data from ACIL Allen.

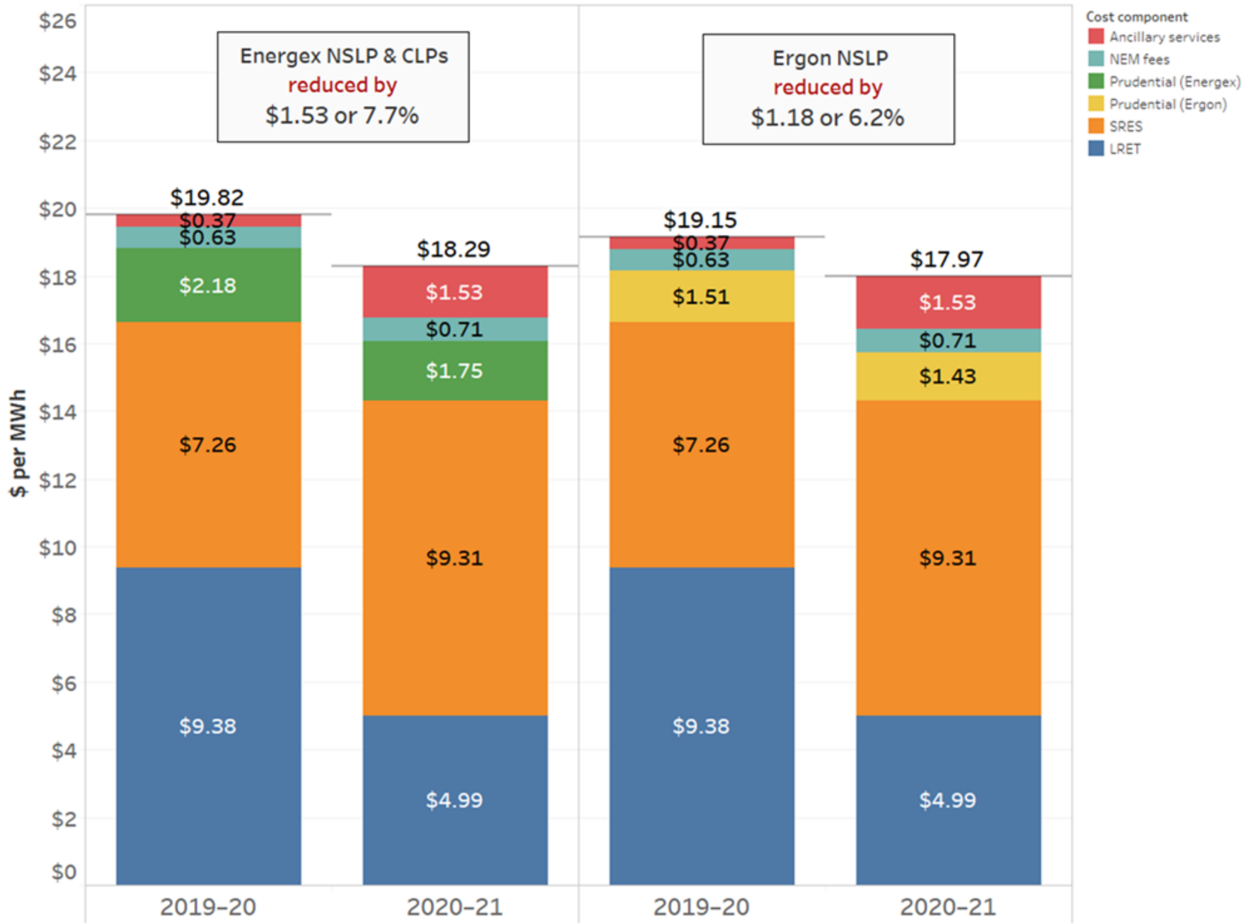
[32] USE is the electricity that cannot be supplied to consumers, resulting in involuntary loss of customer supply (load shedding). USE generally occurs due to insufficient levels of generation capacity, demand response or network capability to meet demand.

Figure 8 Other energy costs—NEM fees, ancillary services charges and prudential costs



Source: Our analysis using data from ACIL Allen.

Figure 9 Total other energy costs



Source: Our analysis using data from ACIL Allen.

Energy losses

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

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

- the average energy-weighted transmission loss factor—estimated by ACIL Allen, using the loss factors and energy consumed at each of the Transmission Node Identities (TNI) provided by AEMO
- the distribution loss factor published by AEMO.

The calculated losses in ACIL Allen's report have been updated to reflect AEMO's recently published 2020–21 published loss factors.

Compared to estimates last year, overall energy loss factors[33] have:

- decreased for small customer tariffs, reflecting a decrease in both transmission and distribution loss factors
- increased for large customer tariffs, reflecting an increase in transmission loss factors.

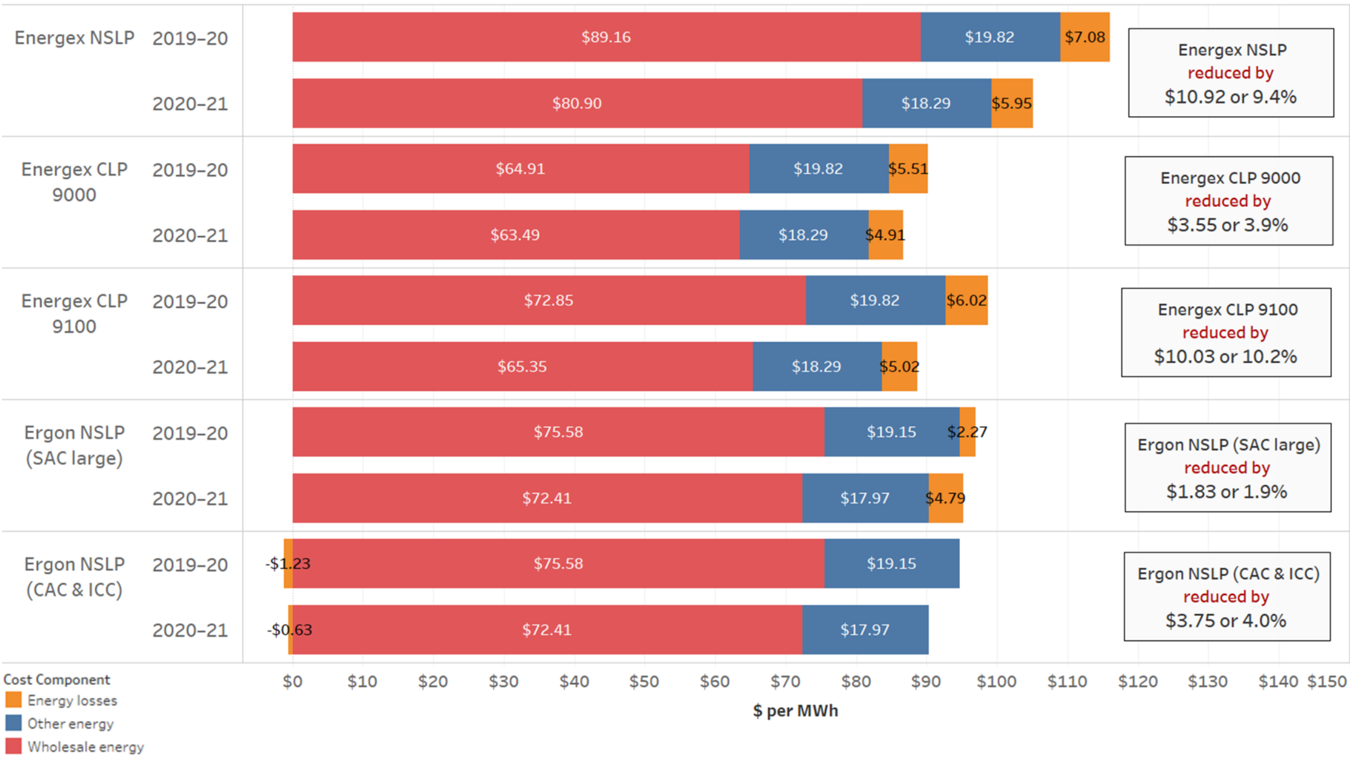
[33] Total energy loss factors are the product of the distribution loss factor and the transmission loss factor.

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

Total energy cost allowances for 2020–21

The chart below summarises the changes in total energy cost allowances for 2020–21.

Figure 10 Changes in total energy cost allowances



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

Source: Our analysis using data from ACIL Allen.

APPENDIX F: COST PASS-THROUGH APPROACH

This appendix provides further information on how we calculated the small-scale energy scheme (SRES) pass-through amounts (discussed in section 5.3). Our approach was to:

- estimate the under- or over-recovery of SRES costs in 2019–20
- make appropriate adjustments to the estimated under- (over-) recovery of SRES costs to determine the amounts to be passed-through in the 2020–21 notified prices.

Under- or over-recovery of SRES costs in 2019–20

First, we calculated the actual cost of SRES compliance during 2019–20 based on the Clean Energy Regulator's (CER's) final small-scale technology percentage (STP) for 2019 and 2020.

We then compared the actual cost of SRES compliance to the SRES allowance in the 2019–20 notified prices, which revealed an under-recovery of $1.968/MWh (0.1968 c/kWh).

Table 4 2019–20 SRES under-recovery for all settlement classes

	Period	*STP*		*Clearing house price (per MWh)*[a]	*SRES cost (per MWh)*	*Average SRES cost (per MWh)*
		Final	*Non-binding*			
2019–20 final determination allowance	1 Jul–31 Dec 2019	21.73%	–	$40.00	$8.692	$7.258
	1 Jan–30 Jun 2020	–	14.56%	$40.00	$5.824	
2019–20 actual cost	1 Jul–31 Dec 2019	21.73%	–	$40.00	$8.692	$9.226
	1 Jan–30 Jun 2020	24.40%	–	$40.00	$9.760	
Under-recovery in 2019–20 (before adjusting for energy losses, the time value of money, variable retail cost allocators and standing offer adjustment/headroom)						$1.968

a *Determined by the Clean Energy Regulator.*

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

SRES pass-through amounts for 2020–21

To estimate the appropriate pass-through amounts for each settlement class, we adjusted the estimated under-recovery of SRES costs to account for:

- energy losses (to determine the SRES liabilities based on energy acquired), by applying a loss factor for each settlement class to reflect transmission and distribution losses—using the loss factors applied in the 2019–20 determination
- the time value of money (to restore the real value of the under-recovered amounts), by applying a nominal weighted-average cost of capital of 6.8 per cent[34]
- the variable retail cost allocators and standing offer adjustment or headroom allowance (consistent with the manner these allowances were applied as part of the 2019–20 determination).

[34] Based on our latest internal analysis.

Table 5 SRES pass-through amounts by settlement class

Energex net system load profile (NSLP)—residential and controlled load tariffs		
A	SRES under-recovery in 2019–20 (c/kWh)	0.1968
B	Energy losses in 2019–20 (total loss factor)	1.065
C	Discount rate (time value of money)	6.80%
D	Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2020–21 c/kWh)	0.2238
E	Variable retail cost allowance (residential) in 2019–20 (%)	11.27%
F	Standing offer adjustment in 2019–20 (%)	5.0%
G	*SRES cost pass-through for 2020–21 (c/kWh)*	*0.2615*
Energex NSLP—small business and unmetered supply tariffs		
A	SRES under-recovery in 2019–20 (c/kWh)	0.1968
B	Energy losses in 2019–20 (total loss factor)	1.065
C	Discount rate (time value of money)	6.80%
D	Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2020–21 c/kWh)	0.2238
E	Variable retail cost allowance (small business) in 2019–20 (%)	12.80%
F	Standing offer adjustment in 2019–20 (%)	5.0%
G	*SRES cost pass-through for 2020–21 (c/kWh)*	*0.2651*
Ergon Energy NSLP—large business and street lighting tariffs		
A	SRES under-recovery in 2019–20 (c/kWh)	0.1968
B	Energy losses in 2019–20 (total loss factor)	1.024
C	Discount rate (time value of money)	6.80%
D	Under-recovery before the application of headroom and variable retail cost allowance (2020–21 c/kWh)	0.2152
E	Variable retail cost allowance (large business) in 2019–20 (%)	6.0445%
F	Headroom allowance in 2019–20 (%)	5.0%
G	*SRES cost pass-through for 2020–21 (c/kWh)*	*0.2396*
Ergon Energy NSLP—very large business tariffs		
A	SRES under-recovery in 2019–20 (c/kWh)	0.1968
B	Energy losses in 2019–20 (total loss factor)	0.987
C	Discount rate (time value of money)	6.80%
D	Under-recovery before the application of headroom and variable retail cost allowance (2020–21 c/kWh)	0.2075
E	Variable retail cost allowance (very large business) in 2019–20 (%)	6.0445%
F	Headroom allowance in 2019–20 (%)	5.0%
G	*SRES cost pass-through for 2020–21 (c/kWh)*	*0.2310*

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

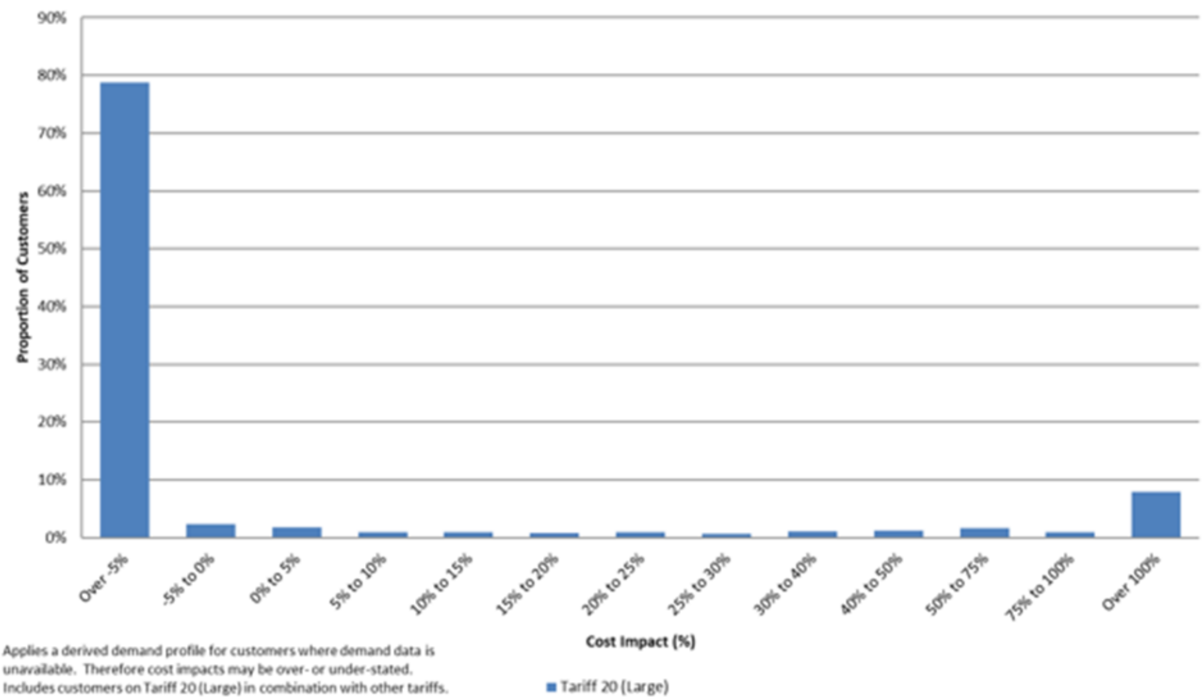
APPENDIX G: OBSOLETE TARIFFS (CUSTOMER IMPACTS)

This appendix supplements section 5.4 of the main report. It contains charts prepared by Ergon Retail of bill impacts for customers moving from 2019–20 obsolete tariffs to an alternative standard business tariff. As some customers are supplied under multiple tariffs, the overall impact to an individual customer may be a combination of the impacts shown below.

Tariff 20 (large)

Transitional tariff 20 (large) aligns with tariffs 44 to 53, which are based on Ergon Energy network tariffs and charges.

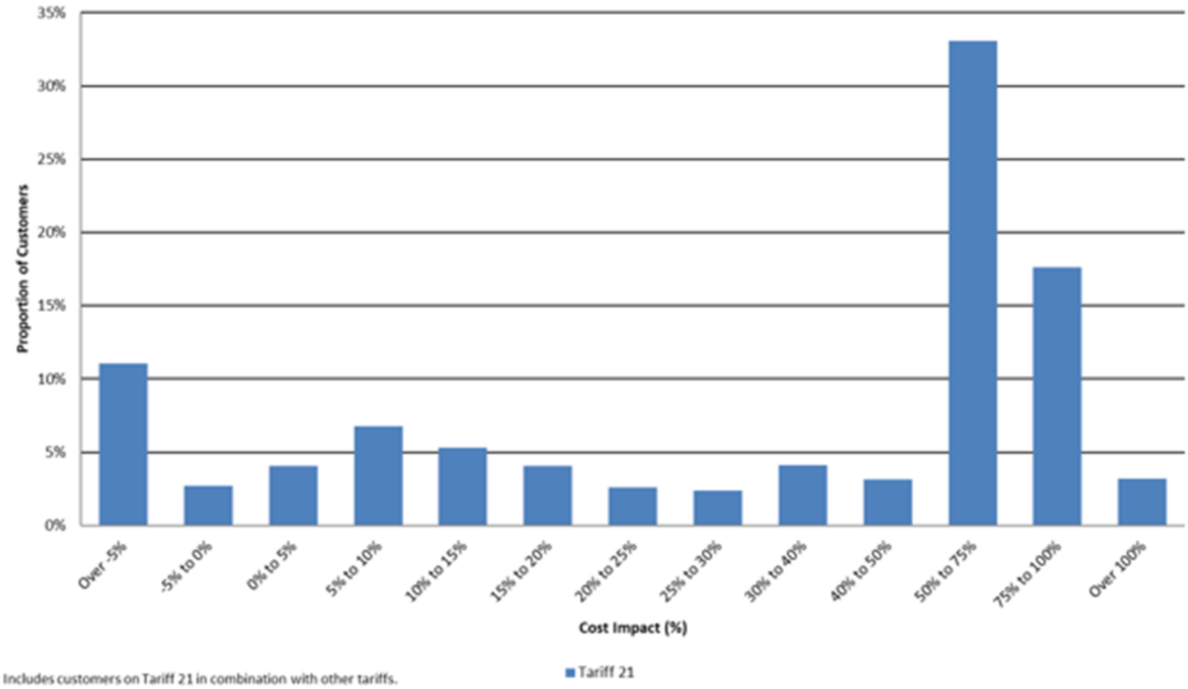
Figure 11 Change in electricity bills for business customers on tariff 20 (large) moving to large customer standard business tariffs



Tariff 21

Tariff 21 is a declining block tariff that aligns with tariff 20 for small business customers.

Figure 12 Change in electricity bills for small business customers on tariff 21 moving to tariff 20



Tariff 22 (small and large)

Transitional tariff 22 (small and large) aligns with tariffs 20 for small business customers and tariffs 44 to 53 for large business customers, which are based on Ergon Energy network tariffs and charges.

Figure 13 Change in electricity bills for large business customers on tariff 22 (small and large) moving to small customer standard tariffs

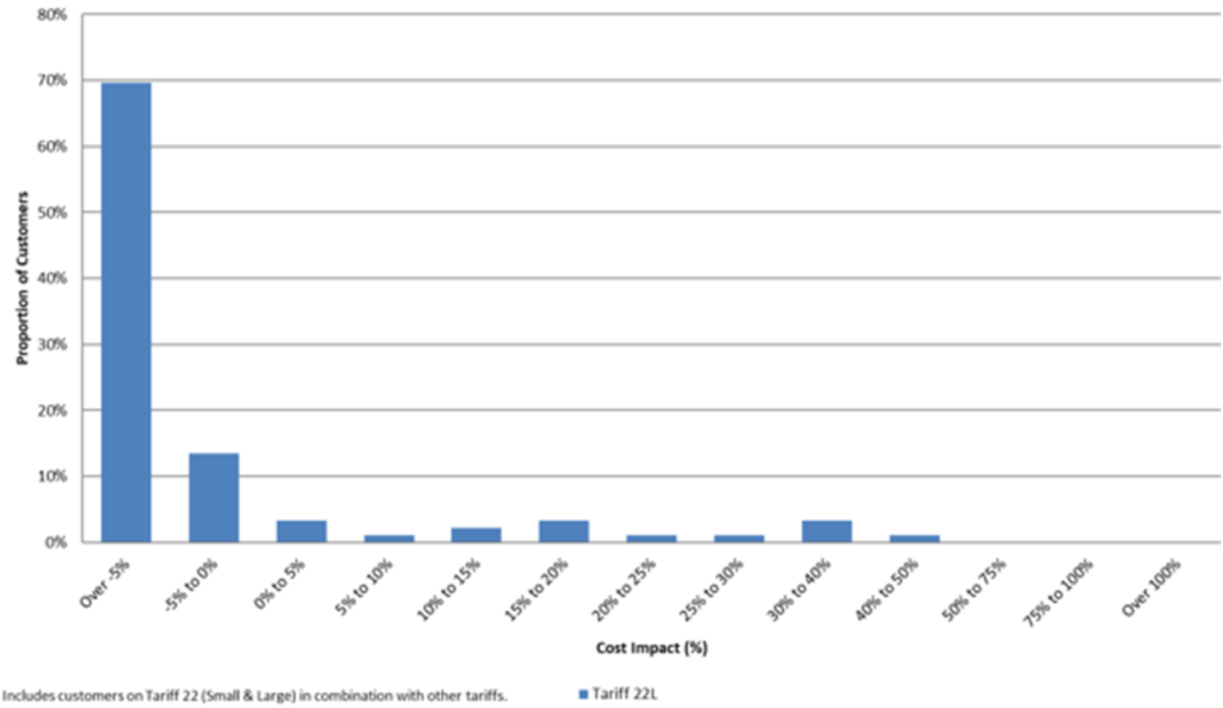
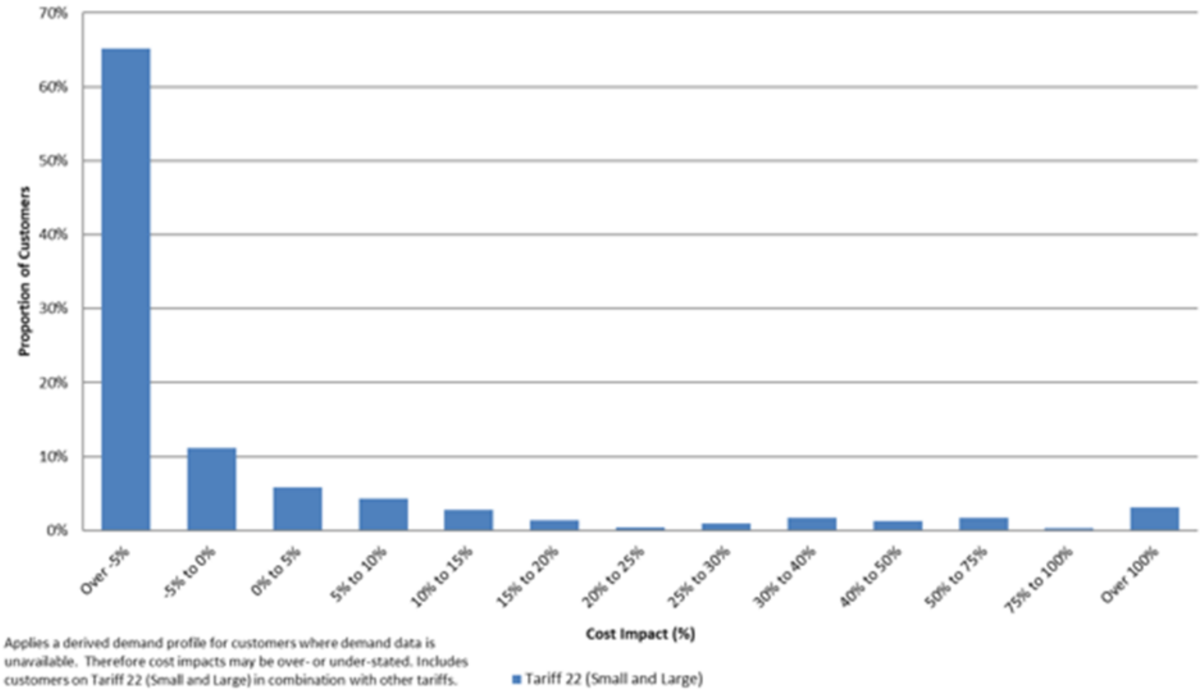


Figure 14 Change in electricity bills for large business customers on tariff 22 (small and large) moving to large customer standard business tariffs



Tariff 37

Tariff 37 is a business time-of-use tariff that aligns with tariffs 20 or 22A for small business customers and one of tariffs 44 to 53 for large business customers.

Figure 15 Change in electricity bills for small business customers on tariff 37 moving to tariff 20

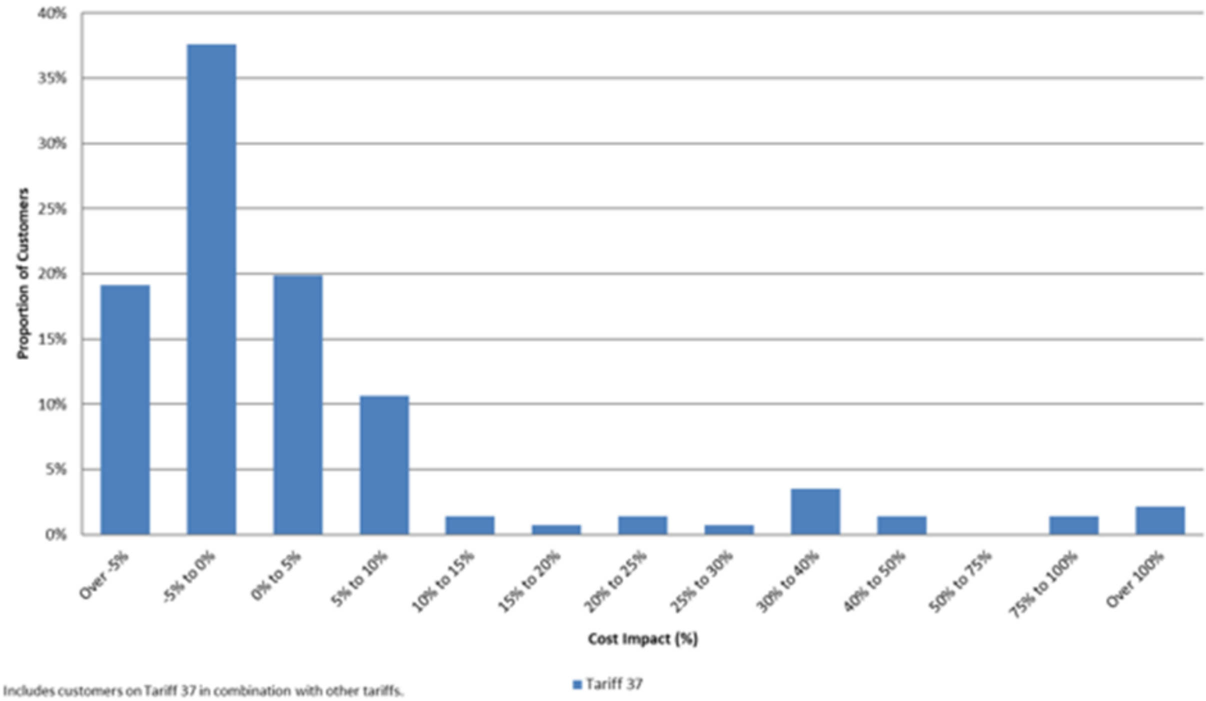
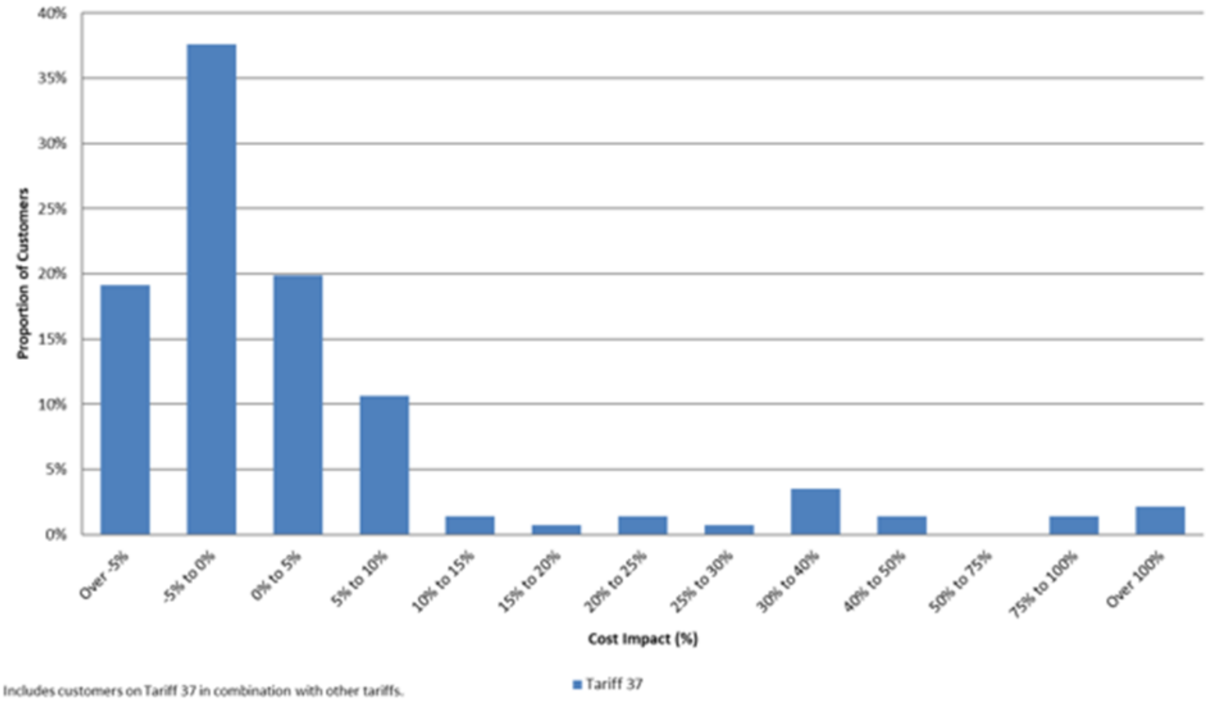


Figure 16 Change in electricity bills for large business customers on tariff 37 moving to large customer standard business tariffs



Tariff 62 and 65

Tariffs 62 and 65 are time-of-use tariffs for farming and irrigation customers. These tariffs align with tariffs 20 or 22A for small business customers and tariffs 44 or 45 for large business customers.

Figure 17 Change in electricity bills for small business customers on tariff 62 moving to tariff 20

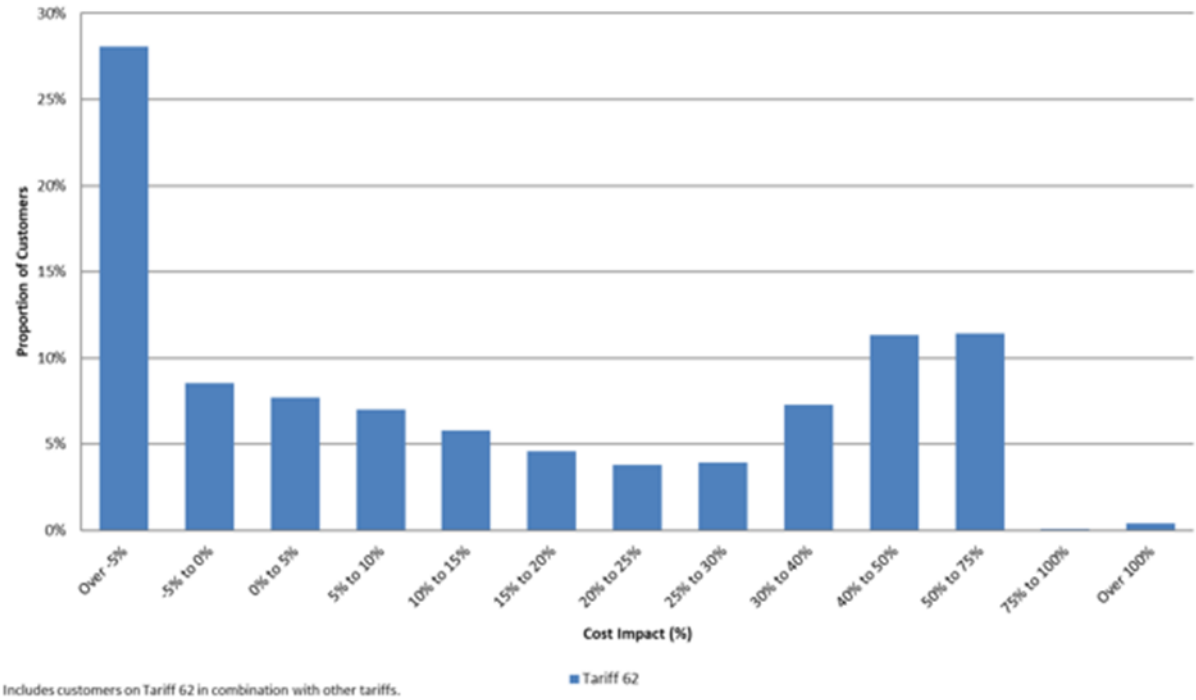


Figure 18 Change in electricity bills for large business customers on tariff 62 moving to large customer standard business tariffs

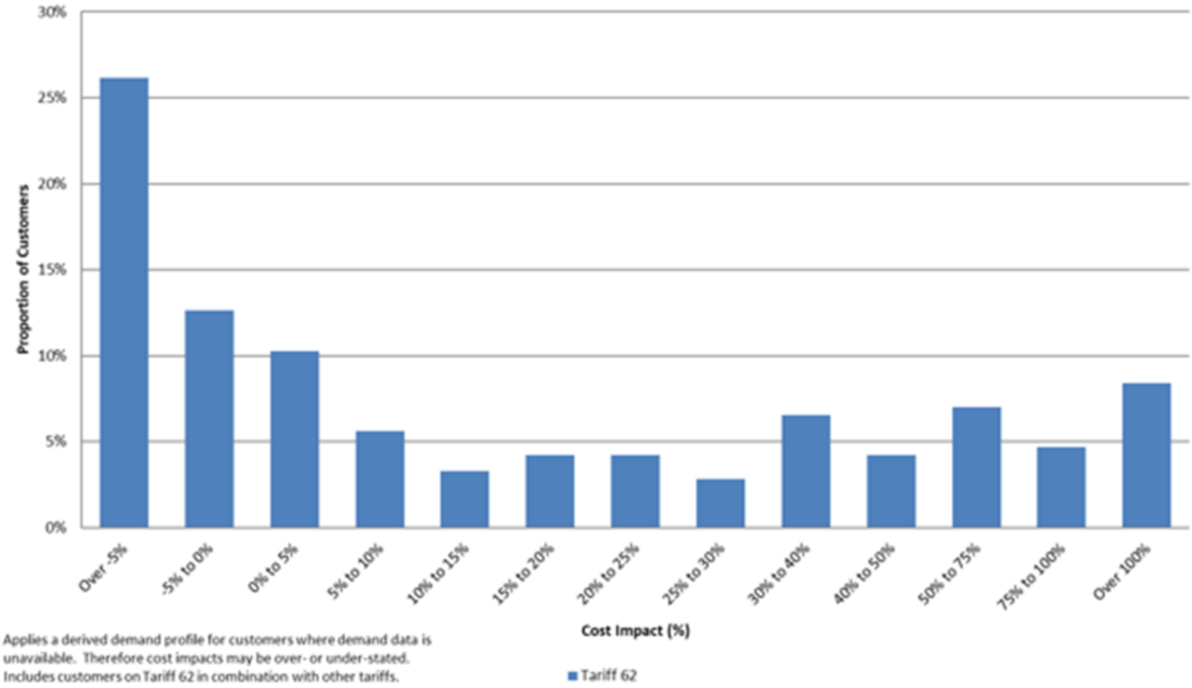


Figure 19 Change in electricity bills for small business customers on tariff 65 moving to tariff 20

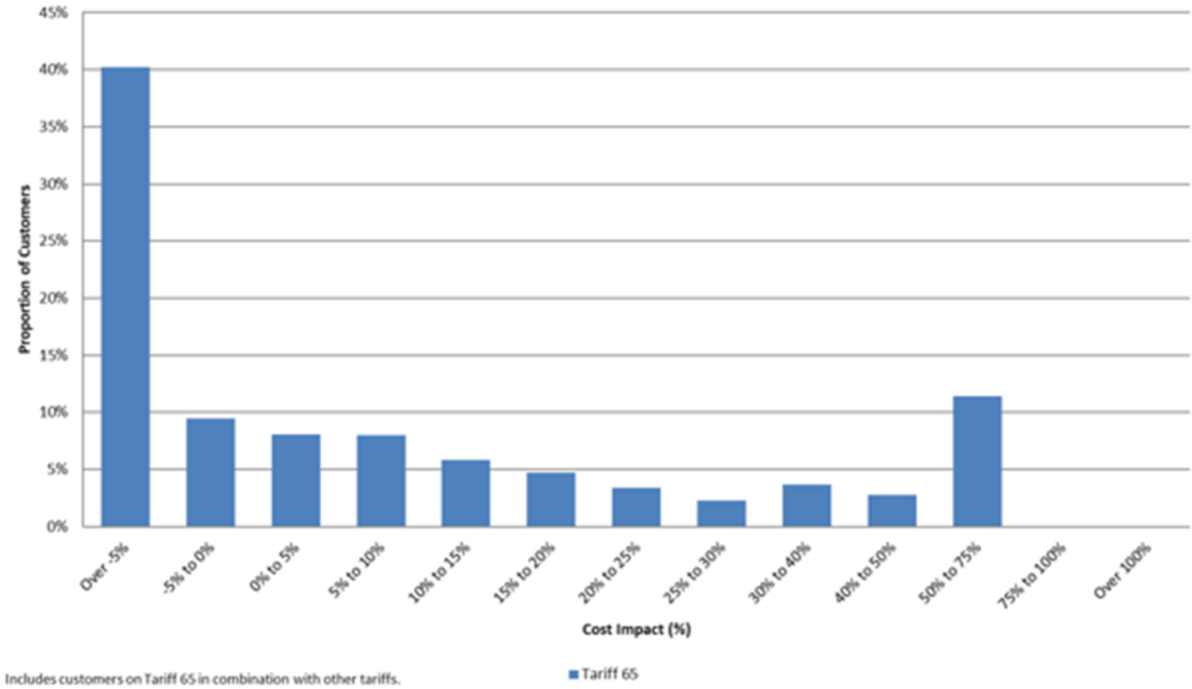
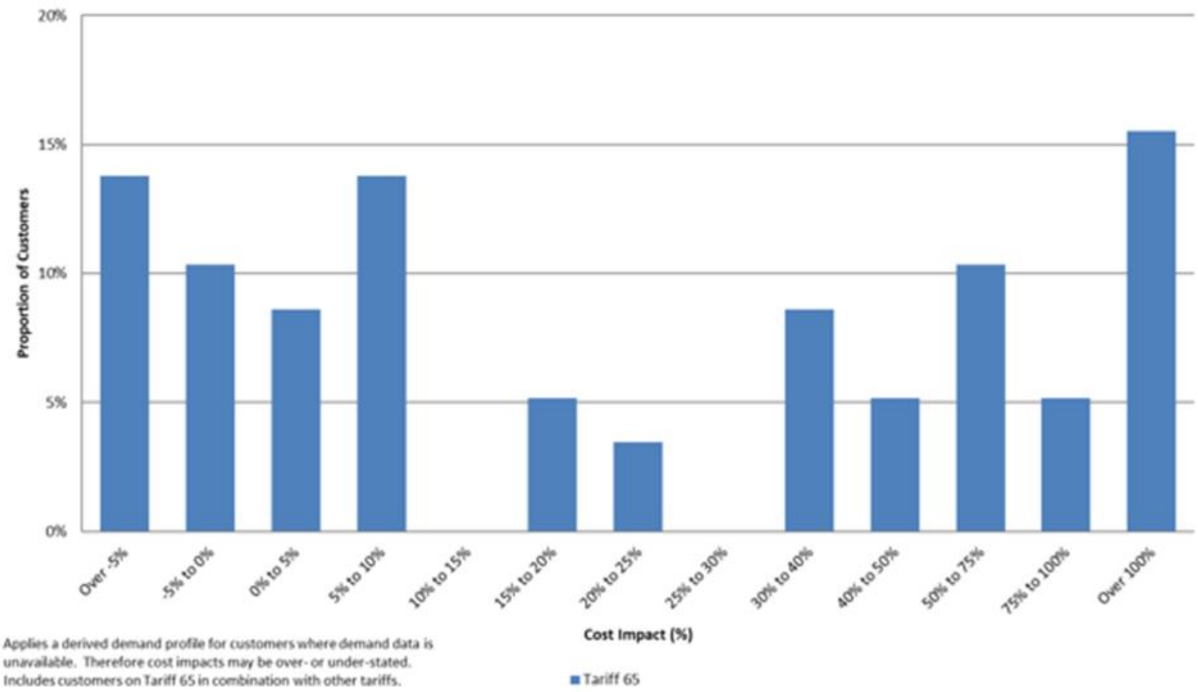


Figure 20 Change in electricity bills for large business customers on tariff 65 moving to large customer standard business tariffs



Tariff 66

Tariff 66 is a flat-rate tariff for irrigation customers. This tariff aligns with tariffs 20 or 22A for small business customers and tariffs 44 or 45 for large business customers.

Figure 21 Change in electricity bills for small business customers on tariff 66 moving to tariff 20

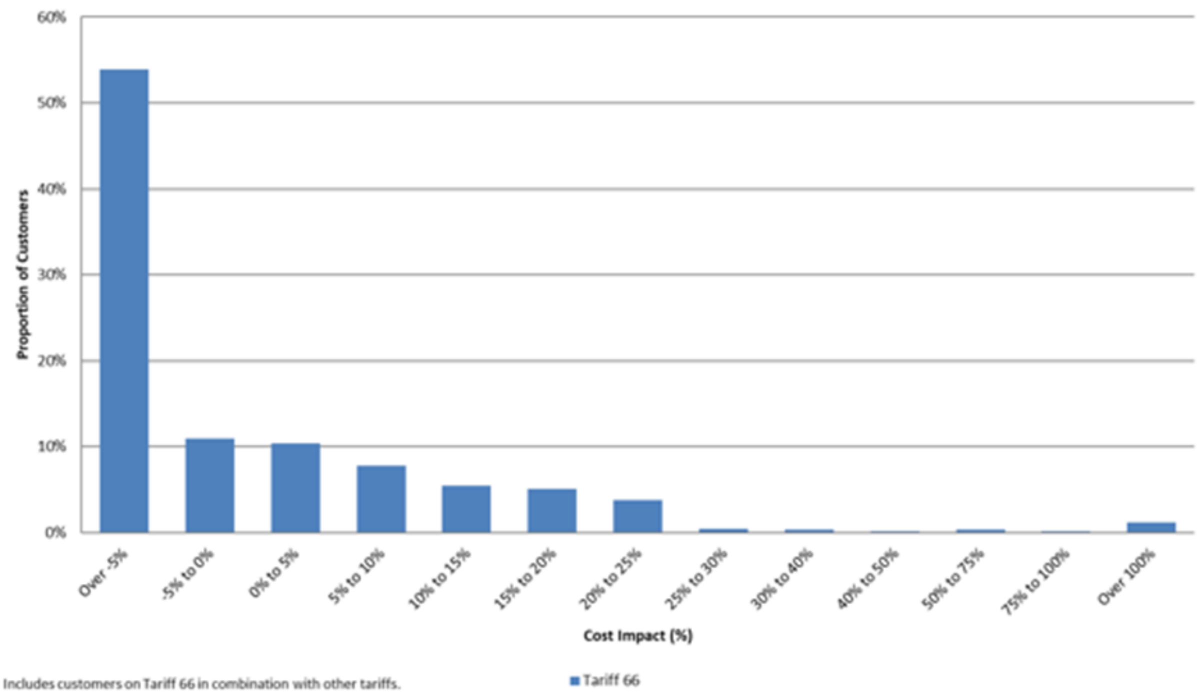
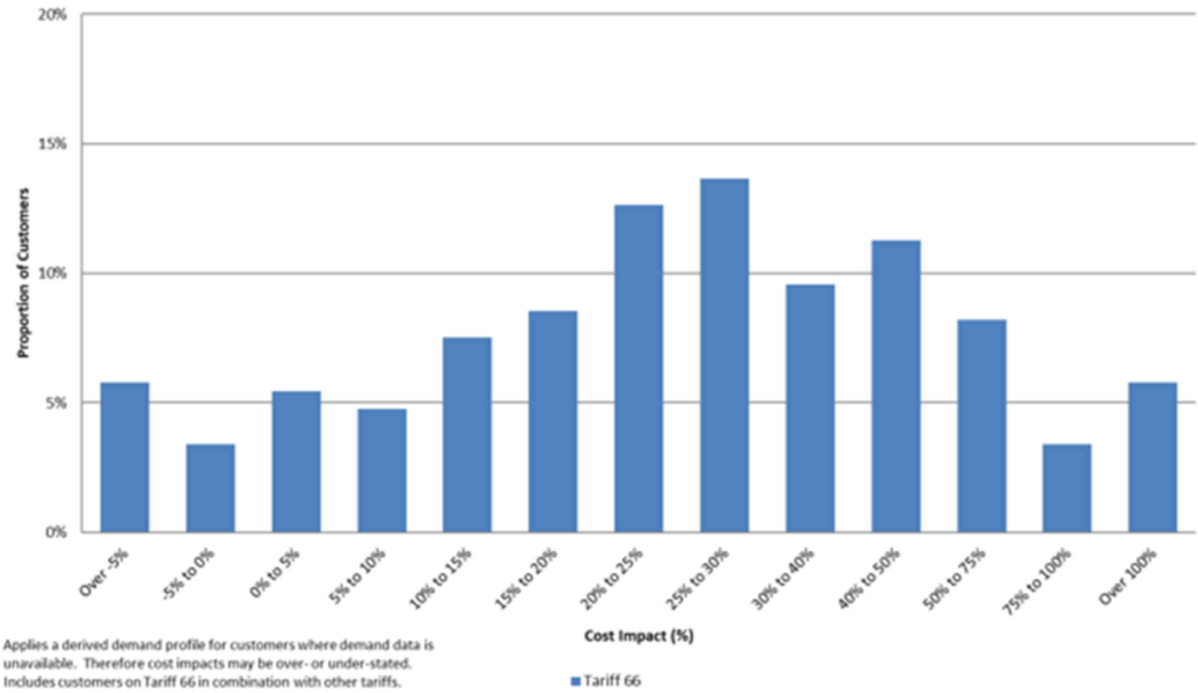


Figure 22 Change in electricity bills for large business customers on tariff 66 moving to large customer standard business tariffs



Applies a derived demand profile for customers where demand data is unavailable. Therefore cost impacts may be over- or under-stated. Includes customers on Tariff 66 in combination with other tariffs.

APPENDIX H: DATA USED TO ESTIMATE CUSTOMER IMPACTS

Typical customer impacts, presented in the final determination charts and tables, use data 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 Distribution provided estimated usage for tariff 22A, while Ergon Retail provided the latest actual usage data for the remaining tariffs, gathered from their customer base of over 700,000 electricity customers in regional Queensland.

Table 6 Usage data to determine customer impacts

Retail tariff	*Usage (kWh per year)*	*Peak usage*	*Off-peak usage*	*Demand (kW per month)*	*Demand threshold (kW per month)*
T11 (only)—median	4,061				
T31—median	1,357				
T33—median	1,025				
T20—median	6,831				
T22A—median	7,457	16.7%	83.3%		
T44—median	184,492			56	30
T45–median	718,376			196	120
T46–median	1,853,889			506	400

APPENDIX I: BUILD-UP OF NOTIFIED PRICES

Table 7 Regulated retail tariffs and prices for residential customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Off-peak/Flat usage (c/kWh)*	*Peak usage (c/kWh)*	*Off-peak/Flat demand ($/kW/mth)*	*Peak demand ($/kW/mth)*
Tariff 11—residential (flat-rate)	Network (incl. JSC)	51.100	8.384			
	Energy		10.514			
	Fixed retail	37.578				
	Variable retail		2.130			
	Standing offer adjustment	1.997	0.467			
	SRES cost pass-through		0.2615			
	Total	**90.676**	**21.756**			
Tariff 12A—residential (seasonal time-of-use)	Network (incl. JSC)	33.937	5.597	37.164		
	Energy		10.514	10.514		
	Fixed retail	37.578				
	Variable retail		1.816	5.373		
	Standing offer adjustment	3.576	0.896	2.653		
	SRES cost pass-through		0.2615	0.2615		
	Total	**75.091**	**19.084**	**55.966**		
Tariff 14—residential (seasonal time-of-use demand)	Network (incl. JSC)	7.596	2.533		6.354	44.241
	Energy		10.514			
	Fixed retail	37.578				
	Variable retail		1.470		0.716	4.986
	Standing offer adjustment	2.259	0.726		0.353	2.461
	SRES cost pass-through		0.2615			
	Total	**47.434**	**15.505**		**7.423**	**51.689**
Tariff 31—night rate (super economy)	Network (incl. JSC)		3.888			
	Energy		8.669			
	Fixed retail					
	Variable retail		1.415			

Retail tariff	Tariff component	Fixed[a] (c/day)	Off-peak/Flat usage (c/kWh)	Peak usage (c/kWh)	Off-peak/Flat demand ($/kW/mth)	Peak demand ($/kW/mth)
	Standing offer adjustment		0.699			
	SRES cost pass-through		0.2615			
	Total		**14.932**			
Tariff 33—controlled (supply economy)	Network (incl. JSC)		4.888			
	Energy		8.866			
	Fixed retail					
	Variable retail		1.550			
	Standing offer adjustment		0.765			
	SRES cost pass-through		0.2615			
	Total		**16.331**			

a *Charged per metering point.*

Note: Totals may not add due to rounding. JSC denotes jurisdictional scheme charges.

Table 8 Regulated retail tariffs and prices for small business and unmetered customers (GST exclusive)

Retail tariff	Tariff component	Fixed[a] (c/day)	Off-peak/Flat usage (c/kWh)	Peak usage (c/kWh)	Off-peak/Flat demand ($/kW/mth)	Peak demand ($/kW/mth)
Tariff 20—business (flat-rate)	Network (incl. JSC)	68.900	8.899			
	Energy		10.514			
	Fixed retail	53.258				
	Variable retail		2.485			
	Standing offer adjustment	6.108	1.095			
	SRES cost pass-through		0.2651			
	Total	**128.266**	**23.258**			
Tariff 22A—business (seasonal time-of-use)	Network (incl. JSC)	59.444	7.648	35.273		
	Energy		10.514	10.514		
	Fixed retail	53.258				
	Variable retail		2.325	5.861		
	Standing offer adjustment	5.635	1.024	2.582		

Retail tariff	Tariff component	Fixed[a] (c/day)	Off-peak/Flat usage (c/kWh)	Peak usage (c/kWh)	Off-peak/Flat demand ($/kW/mth)	Peak demand ($/kW/mth)
	SRES cost pass-through		0.2651	0.2651		
	Total	**118.338**	**21.777**	**54.496**		
Tariff 24—business (seasonal time-of-use demand)	Network (incl. JSC)	8.209	3.142		6.046	60.164
	Energy		10.514			
	Fixed retail	53.258				
	Variable retail		1.748		0.774	7.701
	Standing offer adjustment	3.073	0.770		0.341	3.393
	SRES cost pass-through		0.2651			
	Total	**64.541**	**16.439**		**7.161**	**71.258**
Tariff 41—business low voltage (demand)	Network (incl. JSC)	556.100	1.503		15.843	
	Energy		10.514			
	Fixed retail	53.258				
	Variable retail		1.538		2.028	
	Standing offer adjustment	30.468	0.678		0.894	
	SRES cost pass-through		0.2651			
	Total	**639.826**	**14.498**		**18.765**	
Tariff 91—unmetered	Network (incl. JSC)		6.457			
	Energy		10.514			
	Fixed retail					
	Variable retail		2.172			
	Standing offer adjustment		0.957			
	SRES cost pass-through		0.2651			
	Total		**20.366**			

a *Charged per metering point.*

Note: Totals may not add up precisely due to rounding. JSC denotes jurisdictional scheme charges.

Table 9 Regulated retail tariffs and prices for large business and street lighting customers (GST exclusive)

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Off-peak/Flat usage (c/kWh)***	***Peak usage (c/kWh)***	***Off-peak/Flat demand ($/kW/mth)***	***Peak demand ($/kW/mth)***	***Demand ($/kVA/mth)***
Tariff 44—small (demand)	Network (incl. JSC)	3640.400	1.260		24.652		22.187
	Energy		9.517				
	Fixed retail	381.094					
	Variable retail		0.651		1.490		1.341
	SRES cost pass-through		0.2396				
	Total	**4021.494**	**11.668**		**26.142**		**23.528**
Tariff 45—medium (demand)	Network (incl. JSC)	12033.000	1.260		19.584		17.626
	Energy		9.517				
	Fixed retail	1048.281					
	Variable retail		0.651		1.184		1.065
	SRES cost pass-through		0.2396				
	Total	**13081.281**	**11.668**		**20.768**		**18.691**
Tariff 46—large (demand)	Network (incl. JSC)	31436.900	1.260		16.063		14.457
	Energy		9.517				
	Fixed retail	2666.821					
	Variable retail		0.651		0.971		0.874
	SRES cost pass-through		0.2396				
	Total	**34103.721**	**11.668**		**17.034**		**15.331**

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Off-peak/Flat usage (c/kWh)*	*Peak usage (c/kWh)*	*Off-peak/Flat demand ($/kW/mth)*	*Peak demand ($/kW/mth)*	*Demand ($/kVA/mth)*
Tariff 50— seasonal time-of-use (demand)	Network (incl. JSC)	3025.700	3.018	1.063	9.897	62.898	
	Energy		9.517	9.517			
	Fixed retail	343.197					
	Variable retail		0.758	0.640	0.598	3.802	
	SRES cost pass-through		0.2396	0.2396			
	Total	**3368.897**	**13.532**	**11.459**	**10.495**	**66.700**	
Tariff 71—street lighting	Network (incl. JSC)		13.301				
	Energy		9.517				
	Fixed retail						
	Variable retail		1.379				
	SRES cost pass-through		0.2396				
	Total		**24.437**				

a *Charged per metering point.*

Note: Totals may not add up precisely due to rounding. JSC denotes jurisdictional scheme charges.

Table 10 Regulated retail tariffs and prices for very large business customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Off-peak/Flat usage (c/kWh)*	*Peak usage (c/kWh)*	*Connection unit ($/day/unit)*	*Flat/Off-peak capacity ($/kVA of AD/mth)*	*Flat/peak demand ($/kVA/mth)*
Tariff 51A—high voltage (CAC 66 kV)	Network (incl. JSC)	22181.600	1.296		5.567	3.291	2.866
	Energy		8.975				
	Fixed retail	2639.861					
	Variable retail		0.621		0.336	0.199	0.173
	SRES cost pass-through		0.2310				
	Total	**24821.461**	**11.123**		**5.903**	**3.490**	**3.039**
Tariff 51B—high voltage (CAC 33 kV)	Network (incl. JSC)	15651.000	1.296		5.567	4.025	2.969
	Energy		8.975				
	Fixed retail	2639.861					
	Variable retail		0.621		0.336	0.243	0.179
	SRES cost pass-through		0.2310				
	Total	**18290.861**	**11.123**		**5.903**	**4.268**	**3.148**
Tariff 51C—high voltage (CAC 22/11kV Bus)	Network (incl. JSC)	14519.800	1.296		5.567	4.645	3.599
	Energy		8.975				
	Fixed retail	2639.861					
	Variable retail		0.621		0.336	0.281	0.218
	SRES cost pass-through		0.2310				
	Total	**17159.661**	**11.123**		**5.903**	**4.926**	**3.817**

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Off-peak/Flat usage (c/kWh)***	***Peak usage (c/kWh)***	***Connection unit ($/day/unit)***	***Flat/Off-peak capacity ($/kVA of AD/mth)***	***Flat/peak demand ($/kVA/mth)***
Tariff 51D— high voltage (CAC 22/11kV Line)	Network (incl. JSC)	13873.400	1.296		5.567	9.025	7.260
	Energy		8.975				
	Fixed retail	2639.861					
	Variable retail		0.621		0.336	0.546	0.439
	SRES cost pass-through		0.2310				
	Total	**16513.261**	**11.123**		**5.903**	**9.571**	**7.699**
Tariff 52A—high voltage (CAC STOUD 33-66kV)	Network (incl. JSC)	11207.000	1.255	0.959	5.567	5.647	11.202
	Energy		8.975	8.975			
	Fixed retail	2639.861					
	Variable retail		0.618	0.600	0.336	0.341	0.677
	SRES cost pass-through		0.2310	0.2310			
	Total	**13846.861**	**11.079**	**10.765**	**5.903**	**5.988**	**11.880**
Tariff 52B—high voltage (CAC STOUD 22/11kV Bus)	Network (incl. JSC)	11207.000	1.255	0.959	5.567	3.986	42.198
	Energy		8.975	8.975			
	Fixed retail	2639.861					
	Variable retail		0.618	0.600	0.336	0.241	2.551
	SRES cost pass-through		0.2310	0.2310			
	Total	**13846.861**	**11.079**	**10.765**	**5.903**	**4.227**	**44.748**

Retail tariff	***Tariff component***	***Fixed[a]*** ***(c/day)***	***Off-peak/Flat usage (c/kWh)***	***Peak usage (c/kWh)***	***Connection unit ($/day/unit)***	***Flat/Off-peak capacity ($/kVA of AD/mth)***	***Flat/peak demand ($/kVA/mth)***
Tariff 52C—high voltage (CAC STOUD 22/11kV Line)	Network (incl. JSC)	11207.000	1.255	0.959	5.567	7.307	73.664
	Energy		8.975	8.975			
	Fixed retail	2639.861					
	Variable retail		0.618	0.600	0.336	0.442	4.453
	SRES cost pass-through		0.2310	0.2310			
	Total	**13846.861**	**11.079**	**10.765**	**5.903**	**7.749**	**78.117**
Tariff 53—high voltage (ICC)	Network (incl. JSC)	22181.600	1.296			3.291	2.866
	Energy		8.975				
	Fixed retail	2457.427					
	Variable retail		0.621			0.199	0.173
	SRES cost pass-through		0.2310				
	Total	**24639.027**	**11.123**			**3.490**	**3.039**
ICC site-specific—high voltage	Energy		8.975				
	Fixed retail	2457.427					
	Variable retail		0.621			0.199	0.173
	SRES cost pass-through		0.2310				
	Total	**2457.427**	**9.827**			**0.199**	**0.173**

a *Charged per metering point.*

Note: Totals may not add up precisely due to rounding. JSC denotes jurisdictional scheme charges.

APPENDIX J: DMO BILL COMPARISON AND ADJUSTMENT

The delegation asks us to consider whether the standing offer adjustment[35] needs to be reduced for small customers—in the case, where the resulting notified price bill (including a 5 per cent standing offer adjustment) would exceed the equivalent DMO reference bill in SEQ.

This appendix sets out in greater detail how we:

- undertook a like-for-like comparison between the equivalent notified price bills and DMO bills
- made further adjustments if notified price bills (including a 5 per cent standing offer adjustment) exceeded the equivalent DMO bills.[36]

The AER has determined three DMO annual bills for SEQ for the following tariff groups—residential flat-rate tariff, small business flat-rate tariff and residential flat-rate with controlled load tariffs.[37]

To undertake a like-for-like comparison, we have assessed the components of the DMO bills and notified prices. This included taking account of:

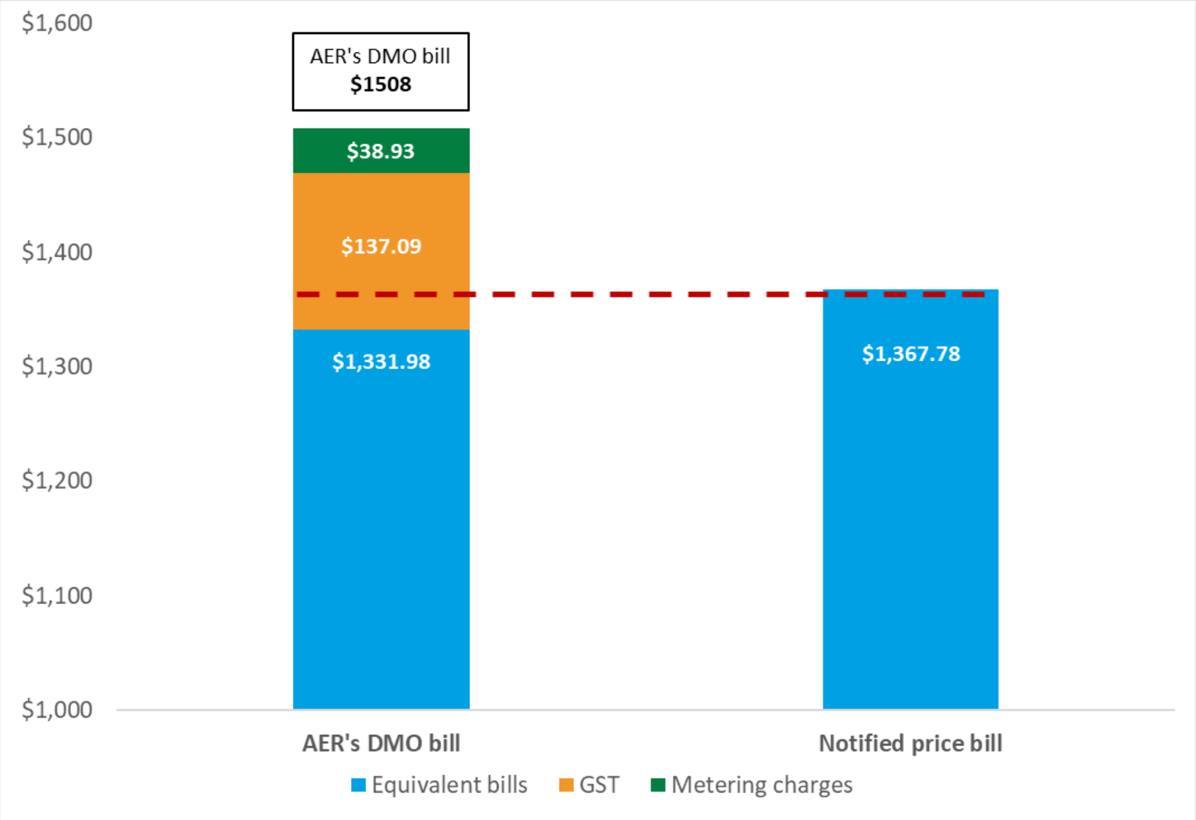
- metering costs, which are included in the DMO bills and are not included in our notified prices. To undertake an equivalent comparison, we have excluded the value of metering costs (i.e. alternative control services charges) from the DMO bills
- GST, which is included in the DMO bills, but not in our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

The following sections show the like-for-like comparison between the equivalent notified price bills and DMO bills after adjusting for the factors as discussed above.

[35] Included in notified prices for small customers
[36] As discussed in section 5.1 of the main report.
[37] AER, *Default Market Offer Prices 2020–21*, final determination, April 2020.

Residential flat-rate tariff (tariff 11)

Figure 23 Residential flat-rate tariff—equivalent DMO bill and notified price bill



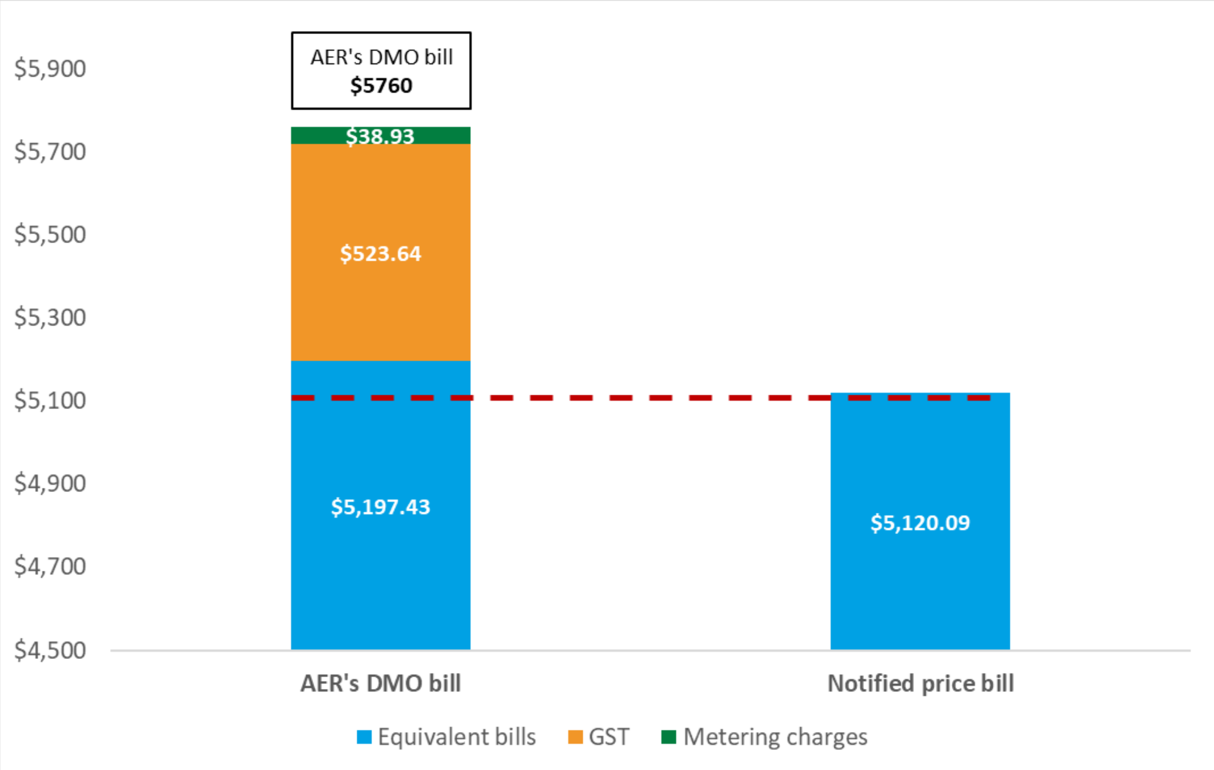
Note: A DMO consumption level of 4600 kWh/annum was used to calculate the equivalent notified price bill.

Source: Our analysis using AER data.

After accounting for the above-mentioned factors, we found that the equivalent notified price bill for tariff 11 is $35.80 higher than the DMO bill. Therefore, we made adjustments to the notified prices of tariff 11 by reducing both the fixed and usage components uniformly until the notified price bill is equal to the DMO bill. The resulting reduction is equivalent to applying a standing offer adjustment of approximately 2.2 per cent (instead of 5 per cent).

Small business flat-rate tariff (tariff 20)

Figure 24 Small business flat-rate tariff—equivalent DMO bill and notified price bill



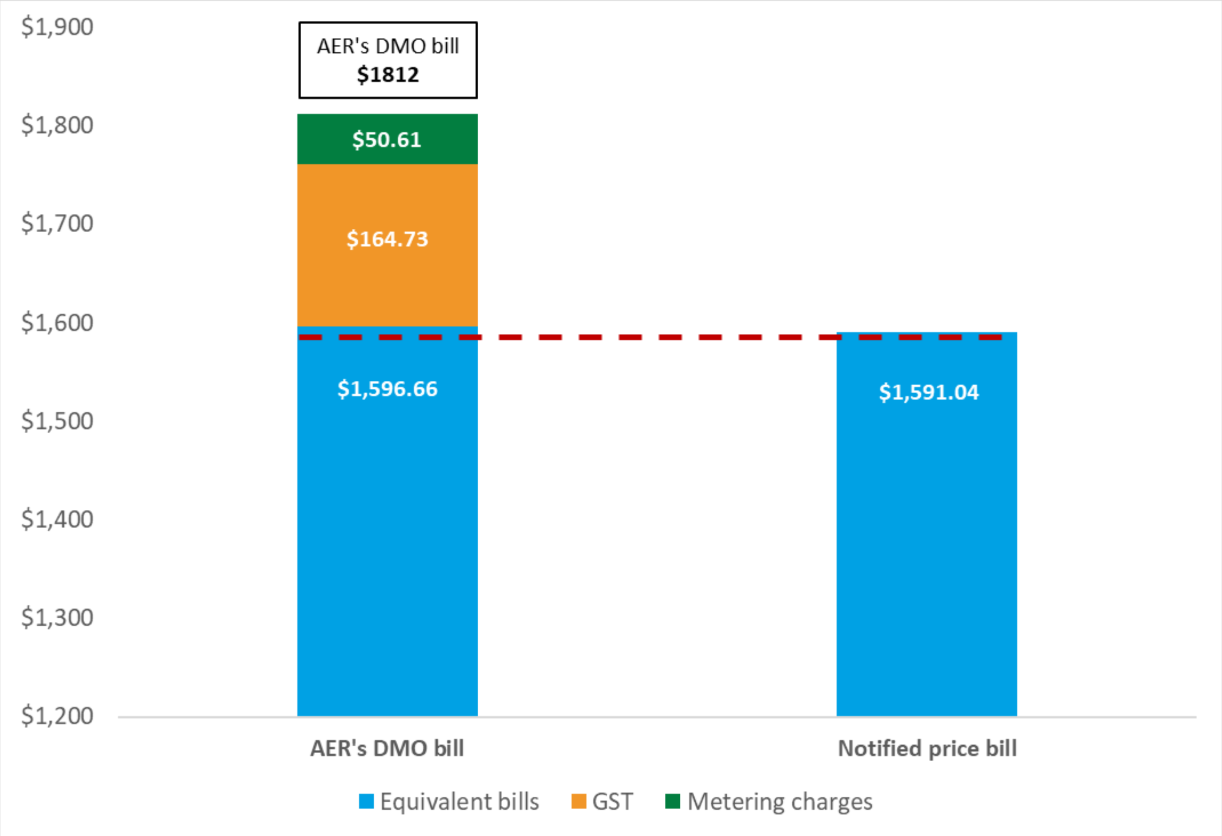
Note: A DMO consumption level of 20000 kWh/annum was used to calculate the equivalent notified price bill.

Source: Our analysis using AER data.

After accounting for the factors discussed above, we observed that the equivalent notified price bill for tariff 20 is $77.34 lower than the DMO bill. Therefore, we do not need to make further adjustments to the notified prices of tariff 20.

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

Figure 25 Residential flat-rate with controlled load tariffs—equivalent DMO bill and notified price bill



Note: A DMO consumption level of 4400 kWh/annum (tariff 11) and 1900 kWh/annum (tariffs 31 and 33) were used to calculate the equivalent notified price bill. Applying the AER's controlled load allocation resulted in a consumption level of 551 kWh/annum for tariff 31 (29 per cent of 1900 kWh/annum) and 1349 kWh/annum for tariff 33 (71 per cent of 1900 kWh/annum).

Source: Our analysis using AER data.

As discussed, we have adjusted the notified prices for tariff 11 such that the equivalent notified price bill is equal to the DMO bill. Consequently, we have used these adjusted notified prices as part of the calculation for the equivalent notified price bill for tariffs 11, 31 and 33.

After accounting for the factors discussed above, we observed that the equivalent notified price bill for tariffs 11, 31 and 33 is $5.62 lower than the DMO bill. Therefore, we do not need to make further adjustments to the notified prices of tariffs 31 and 33.

APPENDIX K: 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 Contact Customers notice dated 5 August 2019, by the Honourable Dr Anthony Lynham MP, Minister for Natural Resources, Mines and Energy.

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 Natural Resources, Mines and Energy (dated 10 December 2019) and sections 90 and 90AB of the Electricity Act, I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2020, 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 25th day of June 2020.

Flavio Menezes, Chair
Queensland Competition Authority

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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.

Where a notified price has been set for a distribution entity *alternate control service*, a retailer can only charge the customer for that service at the notified price.

B) APPLICATION OF TARIFFS

General

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.

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

Additional customer descriptions:

- *Farming* is the undertaking of agricultural or associated business activities for the primary purpose of profit. The primary use of electricity supplied under a farming tariff should be for farming.
- *Irrigation* is the undertaking of pumping water for farming. The primary use of electricity supplied under an irrigation tariff should be for irrigation.
- A *Connection Asset Customer (CAC)* is a large business customer whose required capacity generally exceeds 1500 kVA and annual energy usage generally exceeds 4GWh as classified by the distribution entity.
- An *Individually Calculated Customer (ICC)* is a large business customer whose annual energy usage generally exceeds 40GWh as classified by the distribution entity.

CAC or ICC customers can only access tariffs where specifically stated in the tariff description, or as agreed by the retailer.

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 tariff at that MI. All large customer continuous supply 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. 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, 21, 22, 22A, 24, 41, 62, 65 or 66) 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 unless otherwise stated.

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.

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

The retailer, at its absolute discretion, may switch a customer to an obsolete tariff only once, if that customer:

- Is participating in the Drought Relief from Electricity Charges Scheme (DRECS) on 30 June 2019 and is accessing a tariff classified as obsolete from 1 July 2019; and
- Loses eligibility for DRECS before 30 June 2021; and
- Nominates to return to the tariff now classified as obsolete that they were accessing immediately before their current period of participation in the DRECS.

Any subsequent tariff change by the customer must be to a standard tariff.

The *scheduled phase-out date* is the date an obsolete tariff will be discontinued. Customers on obsolete tariffs may opt to transfer at any time to applicable standard tariffs. Customers on an obsolete tariff on its scheduled phase-out date whom have not notified their retailer of their preferred applicable standard tariff, will be transferred to an applicable standard tariff at the discretion of the retailer upon the tariff being discontinued.

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 *minimum daily payment* only applies when usage charges for the billing period are less than the total of the minimum daily payment multiplied by the number of days in the billing period. Where the total minimum daily payment is charged, usage charges will not apply.

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

Demand is the average rate of use of electricity over a 30-minute period as recorded in kilowatts (kW) on the associated metering, or as recorded or calculated in kilovolt-amperes (kVA) using data recorded on the associated metering. No adjustment to import demand is made for export to the distribution network.

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

For large customer tariffs in Part 2 listing charge parameter options in both kW and kVA, the applicable charging parameter is to be kW or kVA at the customer's choice until 30 June 2021, and kVA from 1 July 2021 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;

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.

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.

Interruptible supply tariffs
General:
These tariffs are applicable when electricity supply is:

(a) connected to approved apparatus (e.g. pool pump) via a socket-outlet as approved by the retailer; or

(b) permanently connected to approved apparatus (e.g. electric hot water system) as approved by the retailer (but not applicable if provision has been made to supply the apparatus under a different tariff during the supply interruption period).

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

Tariff 31
In addition to the general requirements above, this tariff is also applicable when electricity supply is permanently connected to approved specified parts of apparatus (e.g. hot water system booster heating unit), as approved by the retailer, but not applicable if provision has been made to supply the specified part under a different tariff during the supply interruption period except as agreed by the retailer (e.g. for a one-shot booster for a solar hot water system), in which case it 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.

Tariff 33
In addition to the general requirements above, this tariff is also applicable as a primary tariff at the absolute discretion of the retailer.

This tariff shall not apply in conjunction with Tariff 24.

Unmetered supply 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
It is available only to customers with small loads other than street lights as approved by the retailer, 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

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(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 unregulated.

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
Tariff 20 (large)
This tariff cannot be accessed by small customers.

Tariff 21
This tariff shall not apply in conjunction with Tariff 20, 22, 22A, 24 or 62.

Tariff 37
This tariff is applicable when electricity supply is permanently connected to approved apparatus (e.g. electric storage hot water system, apparatus for the production of steam) as approved by the retailer.

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 62
This tariff shall not apply in conjunction with Tariff 20, 21, 22, 22A or 24.

Tariff 65
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 66
The annual 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
Customers previously supplied under tariffs which have been discontinued or redesignated (whether by number, letter or name) will be supplied under other tariffs appropriate to their installations.

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 without the retailer's agreement 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 in this Schedule can only be accessed by customers taking supply at *low voltage* as set out in the *Electricity Regulation 2006* unless it is a designated high voltage tariff, or otherwise agreed with the retailer.

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.

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 large 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 large customers with metering other than types 1 to 4, in addition to the applicable notified prices contained in this Tariff Schedule.

Where the customer refuses telecommunications and a type 4A meter is installed at the customer's explicit voluntary choice, the type 4A surcharge applies as set out in Part 4 of this 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.

EasyPay Reward

From 1 December 2017 until 30 September 2020, small customers of Ergon Energy who participate in the EasyPay Reward Scheme (the Scheme) will receive reward amounts in the form of deferred payments.

As of 31 December 2019 the EasyPay Reward Scheme is no longer available to new participants.

The EasyPay Reward Scheme will operate as follows:

1. An eligible customer who opted-in to the Scheme, and became a participating customer, by notifying Ergon Energy that it agreed to comply with all the participation requirements.
2. If Ergon Energy received a notice mentioned in paragraph 1 before 5 August 2019, it must include the relevant annual amount for the participating customer in:
   (a) the first bill issued to the customer after receiving the notice under paragraph 1, or otherwise, as soon as reasonably practicable thereafter; and
   (b) thereafter—until the Scheme ends on 30 September 2020—the bill Ergon Energy issues to the customer after each anniversary date the customer became a participating customer.
3. If Ergon Energy received a notice mentioned in paragraph 1 after 5 August 2019 but before 1 January 2020, it must include the relevant quarterly amount for the participating customer in:
   (a) the first bill issued to the customer after receiving the notice under paragraph 1, or otherwise, as soon as reasonably practicable thereafter; and
   (b) thereafter, after every 90 day period where the customer has adhered to the requirements, until the customer has received four relevant quarterly amounts.

   The following table illustrates how the Scheme is intended to operate for participating customers other than small, non-reversionary customers:

	Customers who opted in on or before 30.09.18	Customers who opted in after 30.09.18 but before 01.04.19	Customers who opted in after 01.04.19 but before 05.08.19	Customers who opted in after 05.08.19 but before 01.01.20
No. of relevant annual amounts invoiced	3	2	1	N/A
No. of relevant quarterly amounts invoiced	N/A	N/A	N/A	4

Ergon Energy reserves the right to recover the deferred amount from the customer on their next bill.

Definitions for EasyPay Reward Scheme

Eligible customer means a small customer who has an existing account with Ergon Energy under a standard retail contract and who is up to date with their bill payments. A customer with an arrears component or any overdue amount is not eligible for the Scheme unless that customer is participating in the Ergon Energy Hardship program and meeting the requirements under the Hardship Program.

Ergon Energy means Ergon Energy Queensland Pty Ltd (ABN 11 121 177 802)

Initial period means for a period of six months from the date that Ergon Energy issued the bill that includes the first relevant annual amount.

Participating customer means a small customer under a standard retail contract with Ergon Energy who has opted in to the Scheme.

Participation requirements means each of the following:

a) agreeing to receive the relevant annual amount in the form of a deferred payment;
b) agreeing to receive, and receiving, only electronic bills;
c) agreeing to pay, and paying, bills by direct debit, BPAY or CentrePay;
d) agreeing to make, and making, weekly, fortnightly or monthly payments (as agreed) under a *smoothpay* arrangement.
e) if a customer in the Ergon Energy Hardship Program, maintaining their arrangements under the Hardship Program.

Relevant annual amount, for a participating customer, means:

a) if the participating customer is a residential customer—$75; or
b) if the participating customer is a business customer—$120.

Relevant quarterly amount, for a participating customer, means:

a) if the participating customer is a residential customer—$18.75; or
b) if the participating customer is a business customer—$30.

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 alternate control services at the prices regulated by the Australian Energy Regulator for those services, on a cost pass through basis. These charges may be applied to a customer's bill in addition to the notified prices contained in this Tariff Schedule.

Concessional application

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

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

2. Residential institutions:

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

(b) that are:
  (i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and
  (ii) a non-profit organisation that:
    A. imposes no scheduled charge on the residents for the services or accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or
    B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged Care Act 1997* or the *National Health Act 1953*.

3. Organisations providing support and crisis accommodation which:

(a) meet the eligibility criteria of the Specialist Homelessness Services administered by the State Department of Housing and Public Works; 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	21.756	c/kWh
		Daily supply charge	90.676	c
12A	Residential seasonal time-of-use primary tariff	Usage – Peak (Summer 3pm-9:30pm)	55.966	c/kWh
		Usage – All other times	19.084	c/kWh
		Daily supply charge	75.091	c
14	Residential seasonal time-of-use monthly demand primary tariff. *Peak daily demand* is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm during Summer. *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. *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.	Chargeable demand – Peak	51.689	$/kW
		Chargeable Demand – Off peak	7.423	$/kW
		Usage	15.505	c/kWh
		Daily supply charge	47.434	c
20	Small business flat-rate primary tariff.	Usage	23.258	c/kWh
		Daily supply charge	128.266	c
22A	Small business seasonal time-of-use primary tariff.	Usage – Peak (Summer 10am–8pm weekdays)	54.496	c/kWh
		Usage – All other times	21.777	c/kWh
		Daily supply charge	118.338	c

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24	Small business seasonal time-of-use monthly demand primary tariff. *Peak daily demand* is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm during Summer. *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. *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.	Chargeable demand – Peak Chargeable Demand – Off peak Usage Daily supply charge	71.258 7.161 16.439 64.541	\$/kW \$/kW c/kWh c
31	Small customer flat-rate secondary tariff with interruptible supply. 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 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.	Usage	14.932	c/kWh
33	Small customer flat-rate secondary tariff with interruptible supply. 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 times when supply is available is subject to variation at the absolute discretion of the distribution entity.	Usage	16.331	c/kWh
41	Small business monthly demand primary tariff.	Demand Usage Daily supply charge	18.765 14.498 639.826	\$/kW c/kWh c

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Large customer tariffs

Tariff	Description	Charge type	Rate	Unit
44	Large business monthly demand primary tariff	Chargeable demand; or	26.142	$/kW
	Demand threshold 30 kW / 35 kVA.	Chargeable demand	23.528	$/kVA
		Usage	11.668	c/kWh
		Daily supply charge	4021.494	C
45	Large business monthly demand primary tariff	Chargeable demand; or	20.768	$/kW
	Demand threshold 120 kW / 135 kVA.	Chargeable demand	18.691	$/kVA
		Usage	11.668	c/kWh
		Daily supply charge	13081.281	c
46	Large business monthly demand primary tariff	Chargeable demand; or	17.034	$/kW
	Demand threshold 400 kW / 450 kVA.	Chargeable demand	15.331	$/kVA
		Usage	11.668	c/kWh
		Daily supply charge	34103.721	c
50	Large business seasonal time-of-use monthly demand primary tariff.	Peak chargeable demand	66.700	$/kW
	Peak is Summer, being 10:00am to 8:00pm on Summer weekdays for determining chargeable demand, and all day each day for usage.	Off-peak chargeable demand	10.495	$/kW
	Off-peak is all times in non-summer months for determining chargeable demand and usage.	Peak usage	11.459	c/kWh
		Off-peak usage	13.532	c/kWh
	Peak demand threshold 20 kW.	Daily supply charge	3368.897	c
	Off peak demand threshold 40 kW.			
51A	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 66kV.	Demand	3.039	$/kVA
		Capacity	3.490	$/kVA
		Usage	11.123	c/kWh
		Daily connection charge	5.903	$/unit
		Daily supply charge	24821.461	c

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Tariff	Description	Charge type	Rate	Unit
51B	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 33kV.	Demand	3.148	$/kVA
		Capacity	4.268	$/kVA
		Usage	11.123	c/kWh
		Daily connection charge	5.903	$/unit
		Daily supply charge	18290.861	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	3.817	$/kVA
		Capacity	4.926	$/kVA
		Usage	11.123	c/kWh
		Daily connection charge	5.903	$/unit
		Daily supply charge	17159.661	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	7.699	$/kVA
		Capacity	9.571	$/kVA
		Usage	11.123	c/kWh
		Daily connection charge	5.903	$/unit
		Daily supply charge	16513.261	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 is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	11.880	$/kVA
		Chargeable capacity	5.988	$/kVA
		Usage – Summer	10.765	c/kWh
		Usage – All other times	11.079	c/kWh
		Daily connection charge	5.903	$/unit
		Daily supply charge	13846.861	c

Tariff	Description	Charge type	Rate	Unit
52B	Large business high-voltage seasonal time-of-use monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV bus. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	44.748	$/kVA
		Chargeable capacity	4.227	$/kVA
		Usage – Summer	10.765	c/kWh
		Usage – All other times	11.079	c/kWh
		Daily connection charge	5.903	$/unit
		Daily supply charge	13846.861	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. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	78.117	$/kVA
		Chargeable capacity	7.749	$/kVA
		Usage – Summer	10.765	c/kWh
		Usage – All other times	11.079	c/kWh
		Daily connection charge	5.903	$/unit
		Daily supply charge	13846.861	c
53	Large business high-voltage monthly primary tariff only for customers classified as ICC.	Demand	3.039	$/kVA
		Capacity	3.490	$/kVA
		Usage	11.123	c/kWh
		Daily supply charge	24639.027	c
ICC site-specific tariff	Large business high-voltage monthly primary tariff only for customers classified as ICC, where: • the AER approved site-specific network charges are passed-through to customers and • non-network components are chargeable as defined in Part 2 of this Schedule.	AER approved site-specific network charges	Network charges	-
		Demand	0.173	$/kVA
		Capacity	0.199	$/kVA
		Usage	9.827	c/kWh
		Daily supply charge	2457.427	c

Unmetered supply tariffs

Tariff	Description	Charge type	Rate	Unit
71	Business flat-rate primary tariff for street lighting.	Usage	24.437	c/kWh
91	Business flat-rate primary tariff.	Usage	20.366	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
20 (large)	Obsolete large business flat-rate primary tariff. Scheduled phase-out date: 1 July 2021	Usage	37.595	c/kWh
		Daily supply charge	76.858	c
21	Obsolete business declining-block primary tariff. Scheduled phase-out date: 1 July 2021	Usage – first 100 kWh/month	49.357	c/kWh
		Usage – next 9,900 kWh/month	46.374	c/kWh
		Usage – all remaining usage	35.303	c/kWh
		Minimum daily payment	72.631	c
22 (small and large)	Obsolete business time-of-use primary tariff. Scheduled phase-out date: 1 July 2021	Usage – 7am to 9pm weekdays	49.820	c/kWh
		Usage – all other times	17.543	c/kWh
		Daily supply charge	184.717	c
37	Obsolete business time-of-use primary tariff. Scheduled phase-out date: 1 July 2021	Usage – 4:30pm–10:30pm	54.544	c/kWh
		Usage – all other times	21.807	c/kWh
		Minimum daily payment	30.623	c
47	Obsolete large business high voltage monthly demand primary tariff. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022	Chargeable demand	27.864	$/kW
		Usage	12.446	c/kWh
		Daily supply charge	44689.726	c
48	Obsolete large business high voltage monthly demand primary tariff only for customers classified as CAC or ICC. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022	Chargeable demand	28.822	$/kW
		Usage	12.874	c/kWh
		Daily supply charge	46712.140	c

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62	Obsolete farming business time-of-use declining-block primary tariff. Scheduled phase-out date: 1 July 2021	Usage – 7am to 9pm weekdays first 10,000kWh per month	46.516	c/kWh
		Usage – 7am to 9pm weekdays all remaining usage	39.336	c/kWh
		Usage – all other times	16.448	c/kWh
		Daily supply charge	78.451	c
65	Obsolete irrigation business time-of-use primary tariff. Scheduled phase-out date: 1 July 2021	Usage – Peak (daily pricing period)	36.894	c/kWh
		Usage – all other times	20.321	c/kWh
		Daily supply charge	78.003	c
66	Obsolete irrigation business fixed annual dual-rate demand primary tariff. Scheduled phase-out date: 1 July 2021	Fixed charge (annual) – first 7.5kW	37.503	$/kW
		Fixed charge (annual) – remaining kW	112.759	$/kW
		Usage	19.338	c/kWh
		Daily supply charge	171.915	c

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	182.880	c
Standard asset customer (annual consumption greater than 750MWh)	Daily metering charge	217.109	c
Connection asset customer	Daily metering charge	430.155	c
Individually calculated customer	Daily metering charge	493.816	c

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End of Tariff Schedule

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