DRAFT DETERMINATION

Default Market Offer Prices 2020-21

10 February 2020

AUSTRALIAN ENERGY REGULATOR

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Invitation submissions

Interested parties are invited to make submissions on this Draft Determination by 9 March 2020

We will consider and respond to all submissions received by the date in our final decision.

Submissions should be sent to: DMO@aer.gov.au

Alternatively, submissions can be sent to:

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Australian Energy Regulator
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Submissions should be in PDF, Microsoft Word or another text readable document format.

We prefer that all views and comments be publicly available to facilitate an informed and transparent consultative process. Views and comments will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential information will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (June 2014), which is available on our website.[1]

1 https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information

Shortened forms

Shortened form	Extended form
ACCC	Australian Competition and Consumer Commission
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CARC	Customer acquisition and retention costs
CER	Clean Energy Regulator
CL	Controlled load
COAG Energy Council	Council of Australian Governments Energy Council
CPI	Consumer Price Index
DMO	Default market offer
DMO 1	Default market offer determination for 2019-20
DMO 2	Default market offer determination for 2020-21
ECA	Energy Consumers Australia
EME	Energy Made Easy
ESCV	Essential Services Commission Victoria
EWOSA	Energy and Water Ombudsman South Australia
FiT	Feed-in tariff
ICRC	Independent Competition and Regulatory Commission
kW	Kilowatts
kWh	Kilowatt hours
kVa	Kilovolt amperes
LAR	Local area retailer
LRET	Large-scale Renewable Energy Target
MMO	Median market offer

Shortened form	Extended form
MO	Market offer
MSO	Median standing offer
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGL	National Gas Law
NUOS	Network use of system
NSLP	Net System Load Profile
PIAC	Public Interest Advocacy Centre
PV	Photovoltaic system / solar power system
QCA	Queensland Competition Authority
QCOSS	Queensland Council of Social Service
REPI	Retail Electricity Pricing Inquiry
RET	Renewable Energy Target
RPP	Renewable power percentage
SAPN	SA Power Network
SME	Small and medium-sized business customers (enterprises)
SO	Standing offer
SRES	Small-scale Renewable Energy Scheme
STP	Small-scale technology percentage
TOU	Time of use
TUOS	Transmission use of system
UTP	(Queensland) Uniform tariff policy
VDO	Victorian Default Offer

1 Summary

This is our Draft Determination for retail electricity default market offer (DMO) prices to apply from 1 July 2020 to 30 June 2021. The residential DMO prices apply to standing offer customers on TOU and solar tariffs in accordance with proposed legislative amendments the Commonwealth Government is currently considering.

The DMO protects consumers by setting a maximum price a retailer can charge electricity customers on standing offers. It also acts as a reference price that energy retailers must use when advertising or promoting offers. Retailers must show the price of their offer in comparison to the DMO/reference price. This aims to help customers more simply compare the prices of different offers. The Draft DMO prices are indicative based on a set model annual usage level, and are not a 'maximum bill'. An individual customer's actual bill will vary depending on how much electricity they use, their distribution region, and how their retailer has set the fixed and variable charges of their standing offer.

We used a price-based methodology to set the DMO for 2019-20 (DMO 1). It was set at the mid-point between the median market offer price and the median standing offer price available in October 2018. It had the effect of reducing retailers' standing offer prices to the level of the DMO price. In particular, when it came into effect on 1 July 2019, the DMO reduced residential standing offer prices in the region of $118 to $181 per year, depending on the distribution zone. For small business consumers, the DMO reduced standing offer prices by up to $896 per year.

Using the same approach to update the DMO prices for 2020-21 would result in automatically lower DMO prices. We are concerned this would have negative impacts on innovation, investment and market participation for retailers and consumers, reducing incentives on consumers to engage in the market and take advantage of better deals by switching retailers. As the ACCC specified in its REPI report, the DMO is intended as a fall-back for those who are not engaged in the market, and should not be a low-priced alternative to a market offer.

We consider DMO 1 met its objective to lower unjustifiably high standing offer prices. Having now achieved its purpose, our approach going forward is to maintain these savings for consumers, while also providing consumers and retailers incentives to participate in the market.

Our Draft Determination for DMO 2020-21 is therefore to adjust the 2019-20 DMO prices to reflect forecast changes in wholesale, environmental and network costs. We will also adjust remaining costs, including retail costs, to reflect changes in the Australian Consumer Price Index (CPI).

Our Draft DMO prices will change the maximum annual price for residential customers from 1 July 2020 to:

- $9-$16 higher in New South Wales (depending on the distribution zone)
- $86 lower in South East Queensland

- $85 lower in South Australia.

There are marginal increases in DMO prices for residential controlled load (CL) customers in NSW, and similar increases for residential flat rate tariffs. However, for South East Queensland and South Australia, our Draft DMO prices are $147 and $138 lower for controlled load.

For small business customers, from July 2020, the annual standing offer bill will be approximately:

- $23 lower to $46 higher in New South Wales (depending on distribution zone)
- $378 lower in South East Queensland
- $691 lower for South Australia.

The small increases in the NSW regions are driven by forecast increases in wholesale costs. Despite the marginal decrease in the overall forward electricity contract prices (used to forecast wholesale costs), there is a slight increase in contract prices in quarters one and four for 2020-21 compared to 2019-20. These summer quarters tend to display relatively higher volatility in demand and spot price outcomes.

Another reason for the small increase in wholesale costs is the projected continued uptake of small generation units (SGUs) (i.e. household solar PV) in NSW. An increasing number of SGUs are forecast to make electricity usage patterns peakier, resulting in higher hedging costs. Compared to other zones in NSW, wholesale costs in the Endeavour zone are forecast to increase at a slightly higher rate due to time of day load profile shape exhibiting a higher degree of volatility.

The reductions in South East Queensland and South Australia result from forecast reductions in wholesale costs and network costs. Energex and SAPN are currently undergoing a network revenue determination for the control period 2020-25. Larger changes in network cost forecasts observed in these areas result from transitioning between one regulatory period and the next. Higher reductions in variable network costs, in contrast to fixed costs, have led to more significant reductions in the DMO price for controlled load customers in these regions. The decline in wholesale costs is a result of stronger declines in contract prices (compared with New South Wales) and less change in the peakiness of demand profiles due to rooftop PV, which already has high penetration in these regions compared with New South Wales.

We expect environmental costs to fall significantly across all regions and customer types for 2020-21. This is due to an influx of renewable investments coming online in 2020. The change in relative value is approximately the same between zones; however, Energex has a lower total environmental cost due to the absence of jurisdictional schemes, which when presented as a percentage change appears larger.

Residual costs (including retail costs) are adjusted in line with the change in CPI. We assessed potential step changes in retail costs and found no specific adjustments to the Draft DMO prices are warranted.

We are monitoring the impact of DMO prices on the market. This includes monitoring changes retailers make to their standing and market offer prices. As expected, standing offer prices have reduced to the level of the DMO. Market offer prices also generally reduced to the level of the DMO or below for all customer types. Since the introduction of the DMO (comparing December 2019 data to October 2018 data) the median market offer for residential customers reduced by between 2 to 4.5 per cent across all regions, except in the Essential and SAPN regions where it has remained relatively constant.

While it may still be too early to reach definitive conclusions about the impact of the DMO on competition in the retail market, current evidence suggests the DMO has not had a detrimental impact on competition given decreases in market offer prices. However, we continue to monitor the market. Refer to section 3.2.1 for further information.

We outline our model annual usage determinations in Chapter 4. Consistent with the approach in our Position Paper, our Draft Determination is to continue to apply the same annual usage amounts for residential and small business consumers in each distribution region that we used in DMO 1.

We note that, following anticipated amendments to the Regulations, our annual usage determination for residential customers will apply to residential customers on solar and TOU tariffs. Also, our annual usage determination for small business customers will apply to small business customers on solar tariffs. In response to stakeholder feedback, our Draft Determination uses, for each distribution zone, a profile showing electricity usage in each of the 24 hours of the day for TOU tariffs. Chapter 4 sets out our approach to setting the DMO price for these customer types.

Structure of this Draft Determination

Chapter 2 outlines the background and policy objectives for implementing DMO prices and the legislative framework

Chapter 3 sets out our Draft Determination for DMO prices

Chapter 4 sets out our model annual usage determination, covering the annual usage amount and the timing and pattern of supply, including consideration of TOU and Solar customers

Appendix A – List of submitters to AER Position Paper

Appendix B – Market offer analysis for each distribution region

Appendix C – Forecast changes in cost components

Appendix D – Time of use worked example on the application of a daily consumption profile

Appendix E – Calculation of hourly usage from the DMO 1 annual profile

Appendix F – Time of use hourly consumption profiles

2 Background

Who we are

The AER is the independent regulator for Australia's national energy market.

Our functions include regulating electricity networks and covered gas pipelines, in all jurisdictions except Western Australia. We enforce the laws for the National Electricity Market (NEM) and spot gas markets in southern and eastern Australia. We monitor and report on the conduct of market participants and the effectiveness of competition.

We protect the interests of household and small business consumers by enforcing the National Energy Retail Law (NERL). Our retail energy market functions cover New South Wales, South Australia, Tasmania, the ACT and Queensland.

Our goals include driving effective competition where feasible, providing effective regulation where competition is not feasible, and equipping consumers to participate effectively in the market.

This is our Draft Determination for retail electricity default market offer (DMO) prices that will apply from 1 July 2020 to 30 June 2021 in network distribution regions where there is no retail price regulation. We have made this Draft Determination in accordance with the requirements under Part 3 of the Regulations.

How the DMO came about

In the final report of its Retail Electricity Pricing Inquiry (REPI), the Australian Competition and Consumer Commission (ACCC) noted standing offers, originally intended as a default protection for consumers who were not engaged in the market, were unjustifiably high and have been used by retailers as a high priced benchmark from which their advertised market offers are derived. The ACCC found standing offers are no longer working as intended and are causing financial harm to consumers.

To address these concerns the ACCC recommended the introduction of a default market offer to cap what retailers charge residential and small business standing offer customers. It recommended the AER be given the power to set the maximum price for the default offer in each jurisdiction.

The Commonwealth Government accepted the recommendation and made the regulations giving effect to the DMO that commenced on 1 July 2019. The legislative framework for determining DMO prices is contained in the *Competition and Consumer (Industry Code – Electricity Retail) Regulations* 2019 (the Regulations).[2] We have made this Draft Determination in accordance with the Regulations.

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[2] See: https://www.environment.gov.au/energy/electricity-code-consultation

The ACCC was clear the purpose of the DMO was to act as a fall-back for those who are not engaged in the market, and should not be a low-priced alternative to a market offer. It was intended to reduce unjustifiably high standing offer prices, while allowing retailers to recover their costs in servicing customers, and providing customers and retailers with incentives to participate in the market.

DMO 2020-21

The AER's role under the Regulations is to determine DMO prices each year for each network distribution region and customer type. In April 2019, we published our first DMO prices determination, covering the period 1 July 2019 to 30 June 2020. We refer to this throughout this document as our DMO 1 determination.

In developing DMO prices for 2020-21 (DMO 2), we published a Position Paper in September 2019[3] and held a public forum in November 2019 to discuss the issues raised in the Position Paper. We have had regard to submissions we received in response to our Position Paper, as well as feedback provided at the public forum, in formulating this Draft Determination.[4] A list of submitters to the Position Paper is included in **Appendix A.**

Consistent with our preferred position set out in our Position Paper, our Draft Determination is to adjust our DMO 1 prices to take account of forecast changes in the underlying cost inputs, including wholesale energy costs, network costs, and environment costs. The remaining residual costs are adjusted by CPI.

We consider this approach meets all the relevant policy objectives for the introduction of the DMO and criteria set out in the Regulations. We summarise this in section 3.1.

In accordance with the Regulations, we have specified DMO prices as annual price amounts, based on benchmark consumption levels.

In meeting our legislative requirements we have considered the policy intent as reflected in the ACCC's REPI final report, in particular recommendations 30, 32, 49 and 50, and the related commentary.[5]

2.1 What is the default market offer?

The NERL and the National Energy Retail Rules (NERR) include a framework under which all retailers are required to provide services to residential and small business

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3 AER, *Position Paper, Default Market Offer price 2020-21*, September 2019.

4 Our consultation documents and all public submissions to our process are available on our website at https://www.aer.gov.au/retail-markets/retail-guidelines-reviews/retail-electricity-prices-review-determination-of-default-market-offer-prices-2020-21

5 ACCC, *Restoring electricity affordability and Australia's competitive advantage*, Retail Electricity Pricing Inquiry Final Report, June 2018.

customers under a standard retail contract if the small customer does not accept a market offer.[6]

Retailers must publish, on their websites, a standard retail contract for all distribution regions in NEM regions where they operate.[7] Retailers' standard retail contracts must adopt the model terms and conditions set out in the NERR.[8]

As summarised in the ACCC's REPI final report, standing offers were originally intended to provide a safety net for customers who had not engaged in the market, or faced barriers to accessing a market offer, due to credit issues or other reasons. The standard retail contract includes consumer protections not required in all market retail contracts, including:

- access to paper billing
- minimum periods before bill payment is due
- a set period for reminder notices
- no more than one price change every six months.[9]

The DMO price is the maximum price retailers can charge a standing offer customer for electricity in non-price regulated network distribution regions – south-east Queensland (Energex), New South Wales (Endeavour Energy, Essential Energy and Ausgrid) and South Australia (SA Power Networks – SAPN).

The DMO price also acts as a 'reference price' in each distribution region: when marketing or advertising offers, retailers must compare the price of each offer to the reference price. DMO prices are designed to make it easier for customers to compare energy plans across different providers.

2.2 Legislative requirements

The legislative framework for implementing DMO prices and the reference bill mechanism are contained in the Regulations.

Part 2 of the Regulations prescribes a mandatory industry code (the Code) for the purposes of Part IVB of *the Competition and Consumer Act 2010*. Under the Code:

- standing offer prices for small customers must not exceed a price determined by the AER[10]
- small customers must be told how a retailer's prices compare with the AER-determined annual price[11]

[6] NERL, s. 22(1); NERR, r. 16.

[7] NERL, s. 25(1).

[8] NERL, s. 25.

[9] National Energy Retail Rules (NERR) schedule 1, s. 8.2(b); NERR schedule 1, s. 9.1; NERR r. 26; NERR r. 109.

[10] Regulations, s. 10.

- the most prominent price-related feature in an advertisement must not be a conditional discount, and any conditions on other discounts must be clearly displayed.[12]

Part 3 of the Regulations confers price setting functions on the AER. Specifically, we are required to determine:

- how much electricity a broadly-representative small customer of a particular type in a particular distribution region would consume in a year and the pattern of that consumption[13] (the model annual usage)[14]

- a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of a type in a region (the DMO price).[15]

This Draft Determination explains our draft methodology for setting the DMO prices for 2020-21, including our reasoning and responses to stakeholder feedback received in relation to our Position Paper (published September 2019). This is given effect by DMO Draft Legislative Instrument that sets out our draft DMO prices for 2020-21. We outline this in **Appendix J.**

As DMO prices and the reference bill are regulated through an industry code under Part IVB of *the Competition and Consumer Act (2010)*, enforcement of the Code under Part 2 of the Regulations is the responsibility of the ACCC.

The Commonwealth Government has consulted on, and at the time of publication, is in the process of implementing, amendments to some parts of the Regulations.[16]

We expect the amendments relevant to our role in determining DMO prices to include:

- applying the standing offer price cap, reference price and conditional discounting obligations to customers with solar photovoltaic systems
- applying the standing offer price cap to residential TOU tariff customers.

Our Draft Determination sets out our consideration of these issues, on the expectation that these amendments will be in place for the DMO 2 Final Determination.

Revisions not directly relevant to our price setting role are expected to include:

- clarifying demand tariff exclusions
- clarifying obligations around price related communications

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11 Regulations, s. 12.

12 Regulations, s. 14.

13 The AER is not required to determine the pattern of consumption in the case of small business customers.

14 Regulations, s. 16(1)(a).

15 Regulations, s. 16(1)(b).

16 See: https://www.energy.gov.au/publications/competition-and-consumer-legislation-amendment-electricity-retail-regulations-2019

- introducing record keeping obligations
- clarifying the reference price rounding requirements
- ensuring AER determinations are non-disallowable.

2.3 Who does the DMO apply to?

The DMO price applies to residential and small business customers on standing offers in distribution regions where there is otherwise no price regulation, and whose standing offer is of a tariff type for which we determine a DMO price.

Customers on standing offers

The majority of standing offer customers are customers of the 'Tier One' retailers – AGL, EnergyAustralia and Origin Energy.[17] The Tier One retailers are otherwise referred to as Local Area Retailers (LARs), who acquired the customer base of a particular region at the time of retail market privatisation.[18]

The AEMC and ACCC have identified customers on standing offers are those who:

- have not taken up a market offer since the introduction of retail competition in that jurisdiction
- are supplied under a retailer's 'obligation to supply' obligations (for example, if a poor credit history means other retailers will not supply them)[19]
- have moved into a premises and receive supply from the existing retailer supplying the premises but are yet to make contact with the retailer [20]
- have defaulted to a standing offer following the expiry of a market contract.[21]

Table 2 sets out the number and proportions of standing offer customers for DMO areas in quarter 1 of 2019-20.

We note the proportion of residential and small business standing offer customer numbers in DMO areas continues to decline each year.

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17 See AER market performance data: https://www.aer.gov.au/retail-markets/performance-reporting/retail-energy-market-performance-update-for-quarter-4-2018-19. See also AER, *State of the Energy Market Report*, November 2019, pp. 29-34.

18 AEMC, *Advice to COAG Energy Council: Customer and competition impacts of a default offer*, 20 December 2018, pp. 14-15. We note that while AGL and Origin acquired the Energex customer base, Origin is the formally designated LAR under the NERL.

19 Unlike other retailers, under s. 22 of the NERL LARs cannot refuse to supply customers.

20 AEMC, *Advice to COAG Energy Council: Customer and competition impacts of a default offer*, 20 December 2018, p. 15.

21 Section 10 of the Regulations makes clear the DMO price only applies to customers on an electricity retailer's standing offer. It does not apply to customers who are on 'evergreen' ongoing market contracts where discounts have expired, and who in practice are paying a retailer's standing offer prices.

Table 2: Standing offer customers in DMO areas

	Residential standing offer customers (Number and %)	Small business standing offer customers (Number and %)
NSW	382,813 (11.8%)	69,138 (21.1%)
South-east QLD Figures extrapolated from all QLD by excluding Ergon customers. We note other retailers have customers in regional QLD so figure is approximate	176,241 (12.5%)	25,463 (23.8%)
SA	62,269 (8%)	12,860 (14.6%)
Total standing offer customers	**621,323**	**107,461**

Source: AER Retail Market Performance update, Quarter 1 2019-20

Customers in distribution regions with deregulated prices

DMO prices apply in distribution regions not subject to retail price regulation.[22] These regions are:

- New South Wales – Ausgrid, Essential Energy and Endeavour Energy network distribution regions
- South Australia – South Australian Power Networks (SAPN) region
- South-East Queensland – Energex region.

The jurisdictions for which we do not determine a DMO price are:

- The Australian Capital Territory – The Independent Competition and Regulatory Commission (ICRC) regulates the price of electricity supply to small customers of ActewAGL Retail in the ACT, purchasing energy on regulated tariffs.[23]
- The Northern Territory – The Northern Territory Government regulates retail electricity tariffs and charges via an Electricity Pricing Order issued by the

[22] Section 8 of the Regulations specifies that the instrument would not apply in a distribution region if any standing offer prices, or maximum standing office prices, for supplying electricity in the year in the region to a small customer are set by or under a law of a State or Territory.

[23] See: https://www.icrc.act.gov.au/energy/electricity/

Regulatory Minister. The pricing order applies to contestable customers using less than 750 megawatt hours (MWh) per annum.[24]

- Queensland (except for South-East Queensland) – Standing offer retail prices in Ergon's distribution region are regulated under the Queensland Government's uniform tariff policy (UTP) by the Queensland Competition Authority (QCA).[25]
- Tasmania – The Tasmanian Economic Regulator approves the maximum prices that a Regulated Offer Retailer can charge its regulated customers.[26]
- Western Australia – The Western Australian Government regulates Synergy's and Horizon Power's (main retailers) electricity prices through a UTP.[27]
- Victoria – The Essential Services Commission Victoria (ESCV) determines prices for the Victorian Default Offer (VDO). The VDO is a maximum standing offer price for electricity small customers.[28]

2.4 Customer types for which we determine a DMO price

The Regulations set out that we must determine DMO prices for 'small customers' of certain types. These types are:

- *Residential customers* – customers who uses electricity mainly for personal, household or domestic use, and whose prices do not include a controlled load (CL) tariff. A CL tariff applies to a separately metered part of a customer's load, for appliances such as electric hot water storage systems or underfloor heating.
- *Residential customers with CL* – customers who use electricity mainly for personal, household or domestic use, and whose prices include a CL tariff.
- *Small business customers* – customers on flat rate tariffs with no CL, and who use less than 10 MWh per year.

We note the Commonwealth Government is considering amending the Regulations to include residential standing offer customers on TOU and solar tariffs and small business customers whose prices include a solar tariff.[29]

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24 See: http://www.utilicom.nt.gov.au/electricity/Pages/default.aspx

25 See: https://www.dews.qld.gov.au/electricity/regulation

26 See: https://www.economicregulator.tas.gov.au/electricity

27 See: https://www.treasury.wa.gov.au/Public-Utilities-Office/Household-energy-pricing/Electricity-pricing/

28 See: https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer/victorian-default-offer-price-review-2020

29 Department of the Environment and Energy, *Public Consultation Paper, Competition and Consumer Legislation Amendment (Electricity Retail) Regulations 2019*, 22 October 2019, pp. 6-7.

Residential and small business customers are not small customers under the Regulations if:

- their tariff includes demand charges[30]
- they are supplied within an embedded network[31]
- they receive electricity via a pre-payment meter.[32]

Table 3 shows the types of tariffs DMO prices apply to.

Table 3: Tariff types to which DMO prices apply

Tariff type	Residential (non-solar & solar)	Small business (non-solar & solar)
Flat rate (no CL)	✓	✓
Flat rate (with CL)	✓	X
TOU (no CL)	✓	X
TOU (with CL)	✓	X
Demand tariff	X	X
Embedded network customer	X	X
Supplied via pre-payment meter	X	X

30 Regulations, s. 6(3)(a).
31 Regulations, s. 6(3)(c).
32 Regulations, s. 6(3)(b).

3 DMO 2020-21 draft price determination

This chapter sets out our pricing methodology and reasoning for our DMO 2 draft price determination.

Draft DMO prices for customer types in each distribution region are set out in Table 4 below.[33]

Please note the draft DMO prices are based on the most recent data available at the time of publication (early February 2020), and are likely to change for our Final Determination in April 2020 as more current network and wholesale market data becomes available.

Also, the draft DMO prices are indicative prices based on a set model annual usage, and are not a 'maximum bill'. Individual customers' bills will vary depending on how much electricity they use, their distribution region, and how their retailer has set the fixed and variable charges on their standing offer.

In accordance with the Regulations, we have specified DMO prices as annual prices, based on the model annual usage (which incorporates annual usage and a timing and pattern of supply).[34] Under the Regulations, retailers must structure their tariffs to not exceed the DMO annual price for the model annual usage.[35] Our intention is that the residential annual usage determination for flat rate standing offer customers will apply to customers on solar tariffs, and residential customers on TOU tariffs, following the proposed amendments to the Regulations. We discuss our methodology for calculating these usage levels in detail in Chapter 4.

The rest of this chapter covers the following matters:

- the matters under the Regulations that we are required to have regard to in determining DMO prices
- an overview of our DMO 1 approach
- preliminary observations about market changes following the implementation of the DMO 1
- an overview of the DMO 2 pricing methodology. This includes:
    - our consideration of forecast changes in input costs
    - our consideration of retail costs, including our 'step change' framework.

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33 The prices set out in the table are nominal values.

34 Regulations, s. 16(1).

35 The ACCC is responsible for compliance and enforcement under the Regulations.

Table 4: Draft DMO prices – 1 July 2020 (GST inclusive, nominal)

Distribution region		Residential without CL	Residential with CL	Small Business without CL
Ausgrid	DMO 2 Price	$1,483	$2,059	$7,348
	for annual usage of	3,900 kWh	Flat rate 4,800 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 1	+$16 (1.1%)	+$0 (0.0%)	-$23 (-0.3%)
Endeavour	DMO 2 Price	$1,729	$2,193	$6,250
	for annual usage of	4,900 kWh	Flat rate 5,200 kWh + CL 2,200 kWh	20,000 kWh
	Difference to DMO 1	+$9 (0.5%)	+$27 (1.2%)	+$46 (0.7%)
Essential	DMO 2 Price	$1,967	$2,383	$8,081
	for annual usage of	4,600 kWh	Flat rate 4,600 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 1	+$10 (0.5%)	+$8 (0.3%)	+$36 (0.4%)
Energex	DMO 2 Price	$1,484	$1,780	$5,647
	for annual usage of	4,600 kWh	Flat rate 4,400 kWh + CL 1,900 kWh	20,000 kWh
	Difference to DMO 1	-$86 (-5.5%)	-$147 (-7.6%)	-$378 (-6.3%)
SAPN	DMO 2 Price	$1,856	$2,282	$8,429
	for annual usage of	4,000 kWh	Flat rate 4,200 kWh + CL 1,800 kWh	20,000 kWh
	Difference to DMO 1	-$85 (-4.4%)	-$138 (-5.7%)	-$691 (-7.6%)

3.1 Requirements under the Regulations

In making our DMO price determination, we must have regard to the matters under section 16(4) of the Regulations and have used the relevant model annual usage amounts set out in Chapter 4.

We have also had regard to submissions made in response to our Position Paper and stakeholder feedback from our public forum.

Table 5 summarises how we have considered each of the matters under section 16(4) in determining total annual prices.

Table 5: Matters the AER is required to consider in determining DMO prices

Regulations section 16(4)	AER considerations
(a) the prices electricity retailers charge for supplying electricity in the region to that type of small customer	Our DMO 1 determination was made using a price-based approach, using generally available market and standing offer prices. We also considered the DMO price in relation to market offer prices in each area, as well as the LAR's standing offer price. As we are applying an index to the DMO 1 price, these price considerations are embedded in our DMO determination. We have also considered our Draft DMO 2 prices in relation to current market offers in each distribution region (see section 3.2 below).
(b) the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region	In our DMO 1 determination we noted the observed standing and market offers (on a portfolio basis) reflect a typical market participants' expectations about the efficient costs of providing retail services in particular distribution regions, including a reasonable profit margin. We set DMO prices above the observed median market offer in each distribution region to exclude potential below cost prices/loss-leading offers that may not reflect a reasonable profit margin. Our DMO 2 approach aims to preserve the level of retail cost at around the same level by: • indexing the residual retail component by CPI, while allowing material retail cost changes to be passed through to the DMO price

	• adjusting the overall DMO price in line with forecast changes to underlying network, environmental and wholesale costs. This approach will ensure retailers' abilities to make a reasonable profit is not impacted under our DMO 2 determination.
(c) the following costs: (i) the wholesale cost of electricity in the region; (ii) the cost of distributing and transmitting electricity in the region; (iii) the cost of complying with the laws of the Commonwealth and the relevant State or Territory in relation to supplying electricity in the region; (iv) if relevant to the region—the cost of acquiring and retaining small customers; (v) the cost of serving small customers;	For our DMO 2 Draft Determination, we have had regard to the forecast direction and magnitude of changes for the main types of costs, in particular wholesale energy costs, transmission and distribution costs, and environment costs. Specifically, we have had regard to: • forecast changes in the wholesale energy costs for 2020-21. • the AER's pricing determinations for regulated transmission and distribution costs • forecast costs of complying with regulatory requirements such as the LRET, SRES, jurisdictional schemes and feed-in tariff (FiT) schemes. • retail costs component of charges.[36] Additionally, we have considered specific costs for residential TOU customers. How we have had regard to these issues is set out in detail in sections 3.4 and 4.
(d) any other matter the AER considers relevant.	We have had regard to the policy intent for introducing a DMO price as outlined in the ACCC's REPI final report. This was to: • reduce excessive standing offer prices • provide a consistent base from which market offer discounts should be calculated. In recommending a DMO, the ACCC was explicit in its intention the DMO price should be set at levels that: • enable retailers to recover the efficient costs

36 See discussion in section 3.3.

of servicing customers in each distribution region, including costs for acquiring and retaining customers

- do not dis-incentivise competition, customer engagement, innovation and investment. In its submission to our DMO 1 Position Paper, the ACCC re-stated its position that the DMO should not be the lowest or near the lowest price level in the market.[37]

Each aspect of our approach to determining DMO prices is discussed in detail below.

3.2 DMO 1 approach

We determined our DMO 1 price using a methodology based on retailers' observed market and standing offer prices, rather than estimating a retailer's efficient costs using a 'bottom-up' cost assessment.

We set the DMO price at the 50th percentile (mid-way) point in the range between the median standing offer (the upper bound) and median market offer (lower bound) in each distribution region.

We chose these upper and lower points because:

- the median standing offer was an indication of what the majority of standing offer customers were likely to be paying. Given the policy objective of reducing prices for standing offer customers, the DMO price would naturally have to be below this point
- the median market offer provided a reasonable indication of the efficient costs of supplying a customer in each region. To meet the policy objectives of allowing retailers to make a reasonable retail margin and not dis-incentivise competition, innovation, investment and participation, the DMO price would need to be above this point.

While our approach did not require a detailed breakdown of electricity supply cost components, it did require careful judgement and analysis of how the DMO price intersected with market and standing offers.

Based on our analysis and the available evidence, we were satisfied in our Final Determination, that the DMO 1 price balanced the policy objectives of:

37 Submission to the AER Position Paper from the ACCC p. 2.

- *preventing unjustifiably high standing offer prices* – Our DMO 1 price achieved this outcome by being lower than nearly all retailers' standing offers, including those of the relevant local area retailer (LAR) in each distribution region (that is, the retailer with the majority of standing offer customers)
- *allowing retailers to recover their efficient costs* – The DMO 1 price was sufficiently above the median market offer price in each distribution region, which we considered was a reasonable indication of retailers' efficient costs
- *not reducing incentives for innovation, investment, competition and market participation by customers and retailers* – The DMO 1 price was significantly higher than most market offers in each distribution region, meaning customers on a DMO should have an incentive to shop around and switch.

3.2.1 Market analysis – post-DMO 1 implementation

While the Regulations do not directly affect what retailers can charge for market offers, the DMO price cap and reference price are significant regulatory interventions that may have indirect impacts on retailers' market offer pricing over time.

We provided an early analysis of retail prices for the DMO regions in our report on *Affordability in retail energy markets September 2019* (Affordability report), and a further update in the *Annual retail markets report 2018-19*.[38] These reports analysed prices after the introduction of the DMO on 1 July 2019, compared with those in October 2018.

For the Draft Determination we have continued this analysis and looked at prices of retailers' generally available standing offers and market offers at monthly intervals following the introduction of the DMO prices on 1 July 2019, comparing this to offers available in October 2018 (before the DMO methodology was published) and in June 2019 (immediately before the introduction of the DMO).

The purpose of this analysis is to provide a snapshot of how retail electricity prices have changed in the months following the DMO's introduction.

This analysis is preliminary, and we consider it too early to draw strong conclusions about the impact of the DMO. This is because, in a dynamic market we expect electricity retailers will respond to competitors by adapting their offers and pricing and significant changes will likely become apparent over a longer time period.

We also note market offer prices are influenced by changes in network prices that a major component of retail prices. From July 2019 network prices increased in some areas but reduced or remained flat in others. Changes in market offer prices from July may be explained in part by changes in these costs.[19]

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[38] AER, *Affordability in retail energy markets September 2019*, 5 September 2019, Appendix B; *AER Annual retail markets report* 2018-2019, November 2019, pp. 100-108.

Our current observations are consistent with the early findings in the Affordability report. For example:

- as expected, the majority of standing offers and high priced market offers continue to be at or below the DMO price
- median market offers for all tariff types remained relatively constant between October 2018 and December 2019, although median market offers for SME customers experienced the greatest declines compared with other tariff types
- the lowest market offers for all tariff types in December 2019 are at a similar level to those in October 2018.

As mentioned, it is still too early to understand the impact DMO has had on competition. However, since the introduction of the DMO, we have not observed any warning signs in our most recent pricing analysis that the DMO has had an adverse effect on competition.

Detailed analysis of market offer prices is included in **Appendix B**. We highlight key observations from this analysis below.

Standing offer prices

The Regulations require that retailers' standing offer prices must not exceed the DMO price for the relevant distribution area and customer type.

As expected, from July we have seen standing offers reduce to the DMO level.

Market offer prices

The Regulations do not restrict what retailers are able to charge for market offers. However, while retailers are free to set market offers above the DMO level, under the Regulations' reference price provisions they would have to show this in any advertising or marketing material.

From July 2019 we have seen the highest priced market offers in each DMO area reduce to the level of the DMO or below, for all customer types. There are a few market offers above the DMO at 31 December 2019.

We consider the median market offer price in each region an important indicator. It provides a reasonable indication of the efficient costs of supplying a customer in each region. We observe:

- for the period October 2018 to December 2019, the median residential market offer decreased by the largest amount (4.5 per cent) in the Ausgrid distribution region, with smaller decreases (2 per cent) in the Endeavour and Energex distribution regions. It was unchanged in the Essential and SAPN distribution regions
- the median small business market offer price reduced in all areas between 4 to 6 per cent, between October 2018 and December 2019

- between October 2018 and December 2019 the lowest priced offer decreased by 3 per cent in Ausgrid, decreased by 2 per cent in Energex and SAPN's regions, but increased slightly in Essential (2 per cent) and Endeavour (1 per cent)
- the lowest priced small business offer reduced between October 2018 and December 2019 in Ausgrid (14 per cent), Energex (8 per cent) and SAPN (6 per cent).

3.3 Pricing methodology for DMO 2020-21

Under part 3 of the Regulations we are required to set the DMO price each year for standing offer customers on residential flat rate and small business tariffs. This chapter outlines stakeholder views on our pricing methodology proposed in our Position Paper, and the approach set out in our Draft Determination to set DMO 2 prices.

We have considered submissions, and our Draft Determination uses a pricing methodology approach that is consistent with our preferred methodology in the Position Paper. In light of stakeholder submissions to our Position Paper, we have made some refinements to how we calculate forecast changes in input costs and the step change framework. This is covered in section 3.5.

Our Position Paper position

In our Position Paper we propose to update the DMO 1 price for forecast changes in efficient costs of supply for 2020-21. This includes:

- **the wholesale energy, environmental and network costs.** We propose to assess these costs annually as they are subject to both regular and significant changes that are beyond the reasonable control of retailers
- **the remaining retail bill costs** we propose to index by the Australian Consumer Price Index (CPI).

We also outline our preliminary views on a **step change assessment framework.** This is a set of criteria and a process to pass through any additional, material, cost changes to an efficient and prudent retailer's costs of supply (which we expect to occur during 2020-21).

Our initial views were that this approach would ensure the DMO price corresponds with changes in costs, and provides the industry with stability while consumers and retailers continue to adjust to the new rules. It is too early to determine whether this has occurred. The available evidence indicates the DMO 1 price has appropriately balanced the policy objectives and is an appropriate starting point for DMO 2.

In our Position Paper we also consider two alternative approaches for the price methodology. This includes recalculating all components of the DMO price by either reassessing retail market prices or undertaking a bottom-up cost assessment. Our initial views were that these alternative approaches would not suit our policy objectives. There are practical challenges with a bottom-up cost assessment approach, and given the DMO is aiming to remove excess pricing it does not appear to be a proportionate methodology. Most submissions also agree using market prices to reset the starting point could risk market distortions.

Stakeholder submissions

All retailers who responded to the consultation, and the Australian Energy Council (AEC), support our proposal approach of indexing the DMO 1 prices to reflect the forecast changes in efficient costs in 2020-21.[39] The majority of these submissions highlight:

- suitably balances the policy objectives
- our proposed approach would provide some regulatory stability.

The majority of retailers, and the AEC, do not support the alternative price methodology approaches we outlined. Some of these submissions state:

- a bottom-up cost assessment does not correspond to the policy objectives of DMO
- a market-price based approach would be too uncertain and risk market distortions (for example, where retailers attempt to influence the DMO price by temporarily changing their market offer prices).

Simply Energy supports our proposed approach but also considers option 2, to use observed market prices as a starting point for a cost index, has merit.

We recognise that in the design, we could reduce some of the gaming and distortion risks associated with using market offer prices as a starting point for DMO 2. However, we consider we could not remove these risks entirely and a more complex design attempting to mitigate these potential effects could create other market distortion risks.

A number of stakeholders highlight the weightings of the cost components for the base year will influence the future forecast and therefore, any miscalculation of these components for DMO 1 will affect the accuracy of the DMO 2 price.[40]

We discuss specific submission issues raised in relation to the individual cost components in the respective sections below.

PIAC and QCOSS do not support our proposed approach and suggest a bottom-up cost assessment, set at efficient costs, is more appropriate. These submissions comment the AER has not met the policy objectives. This includes:

- noting any price above efficient costs is ‘unjustifiably high’ by definition
- PIAC and QCOSS support the objective that a DMO allow the recovery of efficient retail costs including reasonable retail margins, and that prices above

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39 Submissions to the AER Position Paper from the Australian Energy Council pp.1-2, AGL p.2, EnergyAustralia p.1,

40 Origin Energy pp. 2-3, Ausgrid pp. 3-4.

these are by definition 'unjustifiable'. On this basis, they consider the DMO 1 price has not met the objective of preventing unjustifiably high prices[41]

- PIAC considers the incentives for market participation could be achieved by a more symmetrical market incentive where consumers do not bear the risk and cost of not participating in the market. For instance, the incentive is placed on the retailer to improve efficiency in order to offer lower prices to consumers.

The ACCC was clear the purpose of the DMO is to act as a fall-back for those who are not engaged in the market, and should not be a low-priced alternative to a market offer.[42] The ACCC's submission to our Draft Determination for DMO 1 emphasises the DMO should not be an efficient cost-based price. Its submission notes:

> …the DMO price should not be the lowest price, or close to the lowest price, nor should it be at an 'efficient' level. Rather, its purpose is to act as a reasonable fall-back position for those not engaged in the market for whatever reason or for those that required its additional protections, whilst also allowing scope for continued competition in retail offers.[43]

Importantly, we are mindful the retail market is still in the early stages of adjusting to the recent regulatory changes and reflecting the underlying costs of supply for the 2019-20 period. Whether the DMO 1 price continues to meet our policy objectives is in part contingent on how retailers respond to the DMO. We are therefore monitoring market performance and the impact of the DMO price on market outcomes (see our analysis in section 3.2 and **Appendix B**).[44] Our current market monitoring does not provide evidence to indicate we should change our approach to setting DMO 2. We will continue to monitor this.

Energy Consumers Australia (ECA) highlights the importance of the AER having information gathering powers for the DMO to reduce asymmetry risks when setting DMO prices.[45]

We note the Treasury Laws Amendment (Prohibiting Energy Market Misconduct) Bill 2019 has recently received Assent. This legislation amends the Competition and Consumer Act 2010 to provide the AER with new information gathering powers to compel retailers to provide relevant information to inform DMO determination setting. These new powers provide the AER with a new tool to reduce the risks of information asymmetry in future DMO determinations, if we consider it is necessary and proportionate to use them.

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41 Submissions to the AER Position Paper from PIAC p. 2, QCOSS/Etrog p. 3.

42 Ibid, Chapter 12.

43 Submission to the AER Position Paper from the ACCC pp. 1-2.

44 AER, *Affordability in retail energy markets*, September 2019; This report includes our initial assessment of how retail prices have changed since the DMO was introduced.

45 Submission to the AER Position Paper from ECA p. 3.

Some stakeholders made some suggestions on the DMO 2 pricing methodology that are out of scope of this consultation process. These include:

- QCOSS/Etrog Consulting's recommendation the DMO be extended to cover all consumers rather than only standing offer customers[46]
- QCOSS/Etrog Consulting's suggestion community organisations are resourced to provide support to ensure the DMO and reference bill reforms will deliver tangible outcomes to those in most need[47]
- Red Energy/Lumo's suggestion the ACCC, rather than the AER, be given responsibility for setting the DMO price.[48]

These issues would require changes to the Regulations and are therefore out of scope of the role of the AER in determining the DMO price.

Our Draft Determination

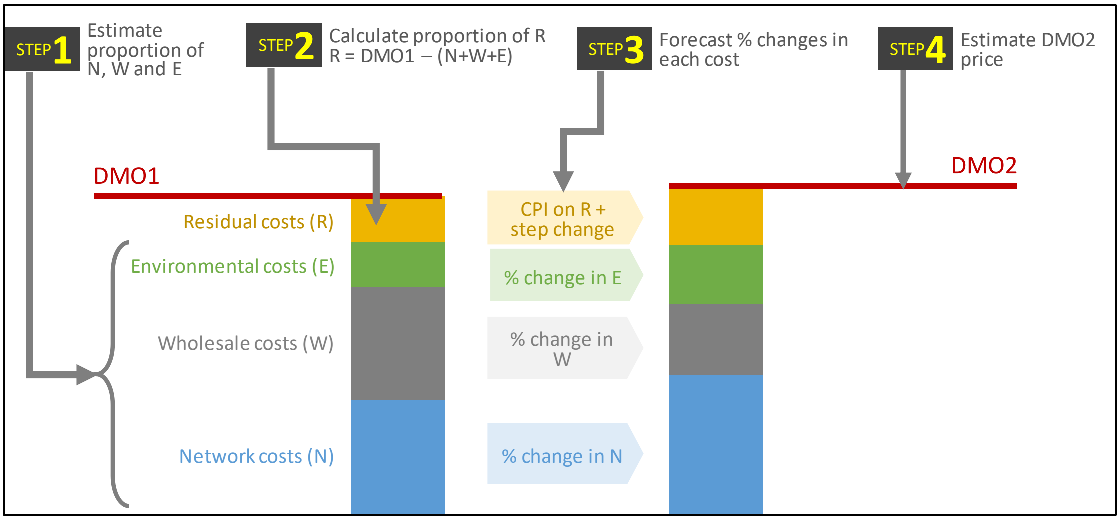
The Draft Determination applies our preferred approach in the Position Paper and updates the DMO 2019-20 for our forecast changes in efficient costs of supply for 2020-21.

The next section considers submissions to the Position Paper on the detailed forecasting methodology for changes to cost inputs.

3.4 Forecast changes in cost inputs in 2020-21

We outline our pricing methodology in Figure 1 below.

Figure 1: Illustrative example of DMO 2 price assessment methodology



[46] Submission to the AER Position Paper from QCOSS/Etrog p. 2.

[47] Submission to the AER Position Paper from QCOSS/Etrog p. 1.

[48] Submission to the AER Position Paper from Red Energy/Lumo, p. 1.

Our forecasts of changes to the cost components between 2019-20 and 2020-21 and the relevant impact on retail prices in each of the distribution regions are set out in Table 6 below.

A detailed assessment of the wholesale and environmental cost forecasts, including inputs provided by the Consultant and issues raised by submissions, is provided in the Consultant's report. We consider the proposed approach by the Consultant is a reliable indicator of costs over the eight years it has been applied in the annual QCA pricing decisions.

Table 6: Forecast changes in cost components and DMO bill impact – 2019-20 to 2020-21 (excl GST, nominal)

Description	Network cost	Wholesale cost	Environmental cost	Overall price impact
Residential without CL				
Ausgrid	+1.8%	+1.9%	-11.2%	**+1.1%**
Endeavour	-1.9%	+4.3%	-11.6%	**+0.5%**
Essential	+0.3%	+2.0%	-12.0%	**+0.5%**
Energex	-8.8%	-4.3%	-14.2%	**-5.5%**
SAPN	-5.6%	-4.3%	-12.3%	**-4.4%**
Residential with CL				
Ausgrid	+1.9%	-0.7%	-11.3%	**0.0%**
Endeavour	-0.8%	+5.0%	-11.6%	**+1.2%**
Essential	+1.6%	-0.0%	-12.0%	**+0.3%**
Energex	-13.8%	-4.5%	-14.2%	**-7.6%**
SAPN	-6.4%	-5.9%	-12.3%	**-5.7%**
Small business without CL				
Ausgrid	-2.8%	+1.9%	-11.2%	**-0.3%**
Endeavour	-1.4%	+4.3%	-11.6%	**+0.7%**
Essential	+0.2%	+2.0%	-12.0%	**+0.4%**
Energex	-11.2%	-4.3%	-14.2%	**-6.3%**
SAPN	-13.9%	-4.3%	-12.3%	**-7.6%**

The key drivers for these changes are:

- **Wholesale energy costs** are forecast to increase slightly in NSW (Ausgrid, Endeavour and Essential regions) and to fall in SE Qld and SA (Energex and SA Power Networks (SAPN) regions respectively). Based on the assumption that retailers build their contract books progressively, our wholesale energy cost allowance is based on currently observed and recent energy contract prices. We have considered the energy price data that are available up to 6 January 2020 in making this determination and will update the wholesale energy cost allowance when we make our final determination. This data shows observed forward contract prices are generally lower in all regions in 2020-21 than in 2019-20, though there are larger falls in SE Qld and SA than in NSW. In particular, all forward contract prices for NSW in quarter one of 2021 are expected to be higher than the contract prices for the first quarter of 2020. Similarly, the base contract prices are higher in quarter four of 2020 compared to the previous year. The expected increase in uptake of rooftop solar in NSW (where solar uptake is low compared to other regions) has resulted in a peakier load forecast in this region. The peakier load is more expensive to hedge and this more than offsets the expected fall in contract prices. This change in peakiness is not as great in SE Qld and SA as the uptake in rooftop PV is greater in these two regions than in NSW. For controlled load customers in NSW, load shifting mitigates periods of peak pricing, with the exception of the Endeavour region where some of the load is shifted to the evening peak.
- **Environmental costs** are forecast to fall significantly across all regions and for all customer and tariff types. We expect large-scale generation certificate (LGC) prices to reduce by 50 per cent because of a surge in renewable investment for the coming year to reach the 2020 LRET target. The significant reduction in LRET compliance costs is partly offset by a forecast increase in the cost of complying with the SRES resulting from more small generation unit (rooftop solar and solar water heater) installations. The cost variations by region mainly result from differences in jurisdictional energy efficiency schemes.
- **Network costs** vary significantly across the regions by customer and tariff type. Energex and SAPN regions are currently undergoing revenue determination resets. The larger changes observed in these regions result from shifting from one regulatory period to the next. For the regions currently within a regulatory period, revenues are smoothed across the period allowing for relatively predictable network price movements. Changes to yearly revenue also occur as a result of under- or over-recovery in previous years, annual incentive rewards/penalties and changes in the annual return on debt.
- **Residual costs** increased by 1.85 per cent across all zones based on RBA's November 2019 Consumer Price Index forecast for the 2020-21 period over 2019-20.

As a part of the step change framework we have also considered the DMO 2 price in relation to retailers' retail costs in 2020-2021, and consider it sufficient to account for these costs. We do not propose any adjustments.

Below is our proposed forecasting methodology for each of the cost components.

3.4.1 Wholesale

Overview

The electricity purchase price to retailers is driven by various factors affecting the supply-demand balance at any point in time. While some supply-demand factors result in long term impacts on the electricity spot price, such as the availability of generation capacity or the change in customer load, short term changes in supply and demand conditions, such as unplanned plant outages or weather events, can cause market volatility, including spot price volatility.

When purchasing electricity from the wholesale market, retailers generally mitigate spot market risks through hedging by entering into electricity futures contracts traded on the Australian Securities Exchange (ASX) or negotiated directly between the parties (over-the-counter), to lock in future electricity prices. As it is unlikely retailer demand matches perfectly with its hedging strategy for each period, retailers typically have residual spot market exposure if they purchase electricity at the spot price (when their demand exceeds their hedged position). They may also sell surplus contracts at the spot price. In addition, there are costs associated with additional services provided in the NEM. They include market fees, such as the Australian Energy Market Operator (AEMO) charges and ancillary service charges for services to manage power system safety, security and reliability.

Our Position Paper position

In the Position Paper we propose a market based approach for the assessment of wholesale costs, making use of financial derivative data. This data is readily available and transparent.

For this Draft Determination, we have used the same approach to forecast wholesale costs changes. This approach has three key parts.

1. **Energy supply requirements (the customer load profile) for each customer type of a retailer.**

   The level and shape of the load profile is a key determinant of the efficient mix of futures contracts and the forecast exposure to the spot. As outlined in the Position Paper, we consider the total consumption in the distribution region (Network System Load Profile or NSLP) and the Controlled Load Profile (CLP) provides a good indicator of typical loads for the customer types relevant to the DMO.

2. **The resulting efficient hedging requirement and approach, or the contracting strategy.**

   An appropriate hedged position is based on a retailer's expectation of wholesale spot price outcomes for the relevant period. A retailer applies a hedging strategy to achieve the optimal hedging product mix and exposure to the spot. We consider a risk averse retailer with an established customer load is an appropriate assumption given our policy objectives, forecasting approach and the information available. In summary, the approach assumes:

- a retailer aims to completely hedge its forecast customer load prior at the commencement of the pricing period.
- the hedge book consists of a portfolio of base, peak and cap quarterly contracts.
- the retailer gradually builds the hedge book, where the prices are weighted by actual trade volumes. There is no assumed starting point for the book build – it would start when the first trade is listed on the ASX Energy pricing and volume information and extend up to 3 months before the beginning of a determination period.

3. The cost of a retailer's hedging strategy and the residual exposure to forecast spot market prices.

Using ASX contract volume and pricing information, we have calculated a contract price for a prudent retailer in each region. This price is the trade weighted average of the daily settlement prices since the contract was listed on the ASX. In regions where ASX volumes are insufficient (for example, in South Australia), the contract prices were informed by data from over-the-counter (OTC) contracts. The spot price forecast includes forecasting half-hourly wholesale spot prices – generally by simulating the NEM using a proprietary wholesale energy market model. The system load for each region of the NEM, satisfied by scheduled and semi-scheduled generation, is used to model regional wholesale electricity spot prices. Annual wholesale costs are obtained by aggregating the contract prices and spot prices, including any difference payments.

In the Position Paper we note there are a variety of retailers in each jurisdiction with different approaches to managing the underlying costs of supply. In seeking to identify the costs of a retailer we acknowledge actual retailer costs may differ. In determining a retailer's load profile our Consultant used all trades, beginning with the first trade recorded by ASX Energy. This approach more closely reflects how a retailer builds a portfolio of hedging contracts over time. It also takes account of how retailers may change their hedging strategies over time to reflect changes in their market share and customer load, including customer churn.

Stakeholder submissions

A number of stakeholders support the market-based approach in their submissions.[49] However, some retailers submitted our approach should consider splitting the Market Settlement and Transfer (MSAT) load profiles into residential and small business profiles.[50] AGL supports the use of NSLP and CLP for load profiles in its submission.

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49 Submissions to the AER Position Paper from AGL p. 3, Origin Energy pp. 4-5, Red Energy/Lumo, p. 2.

50 Submissions to the AER Position Paper from Origin Energy p. 4, Meridian Energy/Powershop pp. 2-3, Red Energy/Lumo p. 3.

However, Red Energy/Lumo disagrees they are the best indicators of load profiles, and suggests the Consultant should give greater weight to profiles that reflect the current state of the market.

Our Consultant assessed the possibility of separating the NSLP into small business and residential profiles. We note in Victoria there was a mandatory roll out of interval ('smart') meters in all five distribution regions in Victoria between 2013 and 2016. They provide the necessary data to split the load profiles for the Victorian Default Offer. Information provided by AEMO to our Consultant suggests few customers within DMO areas are on smart meters. Therefore, there is insufficient data in Qld, NSW and SA to effectively split the NSLP for residential and small business profiles.

For small business customers it is not possible to identify a typical load profile given the large variety of small business customers and range of load profiles.

Therefore, while we do not propose to split the load profiles for DMO 2, we will keep this matter under review when setting the DMO prices for future years, considering changes in the uptake of smart meters and any other relevant factors.

Regarding hedging strategies, Origin Energy supports our characterisation of a prudent retailer's hedging strategy, but notes the strategy needs to sufficiently account for volatility and the linkage between high electricity pool prices and high demand. Powershop notes customer load can change for several reasons, and hedging strategies can become unsuitable for minimising wholesale energy costs unless portfolios are adapted and delta-hedging adopted, which may involve significant cost. Powershop notes applying a long timeframe for historical data can reduce the impact of recent trends and does not account for rapid changes taking place in the market.

AGL notes in its submission some corporate risk management policies could influence a retailer's hedging strategy by establishing minimum levels of hedge cover. A retailer would then engage in trading future spot and contract prices more as a trading activity than a hedging function. AGL also notes our proposed approach does not consider volume risks resulting from customer churn.

Red Energy/Lumo note market-based modelling should reflect retailers' hedging strategies (including appropriate contract weightings and a reasonable level of spot exposure) to manage wholesale costs over a reasonable period of time, while also capturing pricing data as close to the final determination date as possible.[51]

We consider our Consultant's wholesale forecasting methodology is a conservative estimate. In particular, the forecasting methodology takes into account appropriate contract weightings, a range of wholesale market scenarios, including the circumstances in which the retailer has failed to fully hedge its customer load or over-hedge its contracts. This approach does not differentiate by retailer size and therefore does not fully reflect the costs some smaller retailers face in managing their customer load. Our Consultant ran about 500 simulations of demand and spot price outcomes, along with the application of a variety of contracting strategies, and based its estimate

[51] Submission to the AER Position Paper from Red Energy/Lumo p. 2.

of wholesale energy costs at the 95th percentile of the distribution of all outcomes. That is, the outcome used is exceeded by only 5 per cent of the simulated wholesale energy costs outcomes. For the Draft Determination, the market data cut-off date is 6 January 2020.

For spot price modelling some retailers note the approach should appropriately consider recent developments such as rooftop solar uptake and impending plant closures.[52]

As explained in the Consultant report, they have taken into account uncertainty created by the existence of residential rooftop solar generation. Our approach provides for rooftop uptake, adding back estimated rooftop solar generation for the system demand and each NSLP to the historical load profiles. It also accounts for projected uptake using an internal rooftop solar uptake model to forecast the half-hourly load profile.

The Consultant's report provides a detailed overview of our assessment approach, the forecast costs, detailed responses to submissions and the relevant supporting data.

Our Draft Determination

Consistent with our Position Paper, our Draft Determination adopts a market based approach (using financial derivative data) to assess wholesale costs for 2020-21. The forecast wholesale costs combine hedging and spot market costs, as well as other fees related to participation in the NEM wholesale market.

In relation to the matters raised by stakeholders:

- due to the limited data available we propose using the same NSLP to forecast customer load profiles for residential and SME customers
- we consider our forecasting methodology takes into account a wide range of wholesale market scenarios to capture the degree of uncertainty faced by retailers. We do not therefore provide an additional customer load volatility allowance.

The wholesale cost inputs provided by the Consultant are given in Table 7 below. We note the cut-off date for contract prices observed by the Consultant is 6 January 2020.

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[52] Submissions to the AER Position Paper from EnergyAustralia p. 2, AGL p. 3, Origin Energy pp. 2-4, Red/Lumo Energy pp. 3.

Table 7: Wholesale costs for 2019-20 and 2020-21, $/MWh (excl GST, nominal).

Distribution region	Tariff	2019-20	2020-21
Ausgrid	Flat rate	111.36	113.48
	CL1	84.15	75.64
	CL2	79.64	73.88
Endeavour	Flat rate	108.61	113.32
	CL1	98.59	105.37
	CL2	98.59	105.37
Essential	Flat rate	103.17	105.27
	CL1	95.11	90.24
	CL2	95.11	90.24
Energex	Flat rate	98.34	94.07
	CL1	72.52	73.54
	CL2	80.97	75.18
SAPN	Flat rate	164.21	157.14
	CL1	109.65	97.06

Source: Consultant report

3.4.2 Environmental costs

Overview

Environmental schemes at both a Commonwealth and State level require retailers to procure electricity supply from renewable sources and improve customer energy efficiency. The costs of these schemes are incurred by retailers and included as a cost component of the retail price. Environmental costs broadly fall into two main categories — national schemes or the Renewable Energy Target (RET), and jurisdictional green schemes.

The majority of environmental costs relate to complying with the RET (a national scheme). Retailers have an obligation to purchase renewable energy certificates and surrender them to the government in proportion to the overall amount of energy consumed by their customers. The costs of purchasing these certificates are passed on to all customers.

The RET is made up of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). The LRET cost is incurred to acquire the necessary amount of LGCs. LGC certificate surrender for each retailer is determined by the electricity consumed by its customer base in that year multiplied by the Renewable Power Percentage (RPP) set annually for a calendar year by the Minister for Energy.[53] For the SRES, small-scale technology certificates (STCs) are similarly surrendered by retailers. These certificates correspond to electricity generation by rooftop solar photovoltaic (PV) units and solar water heaters. Retailers have the option to either purchase STCs on the market or from the STC Clearing House. STC surrender for each retailer is estimated annually for a calendar year using the Small-scale Technology Percentage (STP).[54]

In addition to the RET costs, a retailer typically also passes through jurisdictional scheme costs. These include energy efficiency incentives to assist consumers in reducing their energy consumption and to drive the uptake of solar PV generation. For some schemes, such as the NSW Climate Change Fund (CCF) and SA jurisdictional scheme obligations (JSO), the distribution network businesses pass associated costs on to retailers through their annual tariffs. For others, such as the NSW Energy Savings Scheme (ESS) and the SA Retailer Energy Efficiency Scheme (REES), retailers incur costs directly and pass them on to their customers.

Our Position Paper position

In our Position Paper, our proposed approach includes three steps to estimate RET costs.

1. **Estimate the RPP and STP** – Consider actual values of the renewable percentages (RPP and STP) for 2020 which would be published by the CER in March 2020, and estimated values for RPP and STP for 2021.
2. **Estimate the LGC and STC price** – Use average LGC prices and clearing house STC prices for both calendar years. The average LGC prices would be estimated using LGC forward prices provided by an energy brokerage company.
3. **Estimate RET** – Compute RET costs for the relevant calendar years by multiplying certificate prices with renewable percentages, and averaging the two calendar years to derive the costs for financial year 2020-21.

Stakeholder submissions

A number of retailers suggest LGC forward market prices are not representative of retailers' actual costs incurred as per their respective long-term PPAs with large-scale renewable energy generators, or internal investment in renewable energy generation units for vertically integrated companies.[55]

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53 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-renewable-power-percentage, viewed 17 September 2019.

54 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage, viewed 17 September 2019.

55 Submissions to the AER Position Paper from AEC pp. 2-3, AGL p. 3, EA, Origin Energy pp. 4-5, Meridian Energy/Powershop p. 3.

We note the majority of PPAs were entered into several years ago, therefore the cost of the green component (the LGCs) may be higher than the cost of acquiring the LGCs through a brokerage platform. We agree retailers would not typically rely on the spot market to acquire LGCs, but would also acquire LGCs in years leading up to the relevant pricing period. However, the use of PPAs by the AER also raises questions about which PPAs, and what time period should be used to forecast PPA costs. We understand not all PPAs divide out LGC prices, but have a bundled price.[56] We acknowledge retailers are likely to take a longer term approach to LGCs, however, from a practical perspective, benchmarking over the longer term to determine green energy prices for a given year is challenging.

There are various long-term approaches to acquiring LGCs, such as through PPAs, vertical integration, or joint ventures. This is because decisions to enter into such long term arrangements are likely driven by several commercial factors in addition to the need to surrender LGCs, such as hedging against the wholesale spot price. Vertically integrated retailers also enter into long term arrangements to supply LGCs and wholesale energy contracts to other liable entities and their own retail arms. However, given the range of durations and commercial drivers for these arrangements it is difficult to identify which PPAs a retailer would have and what an efficient price for 2020-21 is. Given this complexity, we consider LGC brokerage prices, that are transparent, publicly available and a function of market conditions, remain the best available proxy for assessing the cost of acquiring LGCs.

AGL and Origin Energy also highlight that non-binding STPs have historically been unreliable and lead to underestimation.

With continued growth in residential solar installations, we acknowledge the current STP non-binding estimates are under-estimated. Our Consultant revised the STP estimates for 2020 (for the financial year 2020-21 only) and 2021 to better reflect the forecast STP for our Draft Determination. For the Final Determination, the Consultant-revised 2021 STP estimate may still be used if the CER non-binding STP estimates to be published in March 2020 do not take into account the growth trend in solar installations.

Our Draft Determination

In light of the submissions we received, our Consultant has calculated revised estimates for the 2020 and 2021 STPs.

All other aspects of our environmental cost forecasting approach remain consistent with our Position Paper. For more information on the approach and consideration of the submissions to the Position Paper, see the Consultant’s report.

The environmental cost inputs derived by the Consultant using the approach outlined above are given in the table below.

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[56] AEMC, *Residential Electricity Price Trends Methodology Report 2018*, 21 December 2018, p. 41.

The jurisdictional energy efficiency schemes, and network losses (which impact the cost environmental cost forecasts) vary between zones. As a result, the total forecast environmental costs ($/MWh) are different across the zones.

Table 8: Environmental costs for 2019-20 and 2020-21, $/MWh

Distribution region	Tariff	2019-20	2020-21
Ausgrid	Flat rate	19.34	17.17
	CL1	19.42	17.22
	CL2	19.42	17.22
Endeavour	Flat rate	19.45	17.19
	CL1	19.45	17.19
	CL2	19.45	17.19
Essential	Flat rate	19.51	17.17
	CL1	19.51	17.17
	CL2	19.51	17.17
Energex	Flat rate	17.72	15.21
	CL1	17.72	15.21
	CL2	17.72	15.21
SAPN	Flat rate	21.25	18.63
	CL1	21.25	18.63

Source: Consultant report

3.4.3 Network costs

Network costs in a retail electricity bill represent the cost of transporting electricity through transmission and distribution networks.

Under the National Electricity Rules (NER), the AER regulates network charges, approving network tariffs that the DNSPs annually set for customer use of the network. Network tariffs are typically constituted of two components.

1. Network Use of System (NUOS) charges largely recover the costs of providing transmission and distribution of electricity through network infrastructure. These include the costs of jurisdiction-specific schemes that are recovered across the entire customer base.
2. Metering charges relating to the DNSP's installation and maintenance of type 5 manually-read interval meters and type 6 accumulation meters.

Our Position Paper position

In the Position Paper we note retailers typically pass through the applicable network tariff to their customers. The Regulations require the AER to make our DMO determination by 1 May of each year. Given the timing of annual network tariff approvals, in the Position Paper we propose to consider changes in annual revenue from network businesses' revenue determinations to estimate changes in network costs. In addition, we propose having regard to additional network pricing information by consulting with network businesses.

We noted in the Position Paper that, given the timing of annual network tariff approvals, particularly for the distribution regions undergoing a revenue determination (SAPN and Energex), our cost assessment may not be able to incorporate actual changes in annual tariffs. This is because the Regulations require the AER to make our DMO determination by 1 May of each year.

For all jurisdictions, aside from Victoria, we usually assess and approve the following financial year's tariffs by mid-May of each year. However, this process is delayed if we also make a network business' five year revenue determination.

In the absence of a relevant financial year's approved network tariff, in our Position Paper we indicated the best available forecast is the annual change in revenue provided in the AER's network revenue determinations.

Stakeholder submissions

Some retailers and Ausgrid[57] note that the AER should only rely on the relevant network tariffs when forecasting changes in costs rather than using the annual changes in network revenue determinations. Retailers reiterate concerns we raised in the Position Paper that the annual changes in network revenue determinations do not account for other factors that affect annual network tariffs, such as the annual under- or over-recovery of network revenues within a revenue determination period.

Retailers suggest these other factors can be taken into account in one of three ways: delaying the DMO final determination, applying a true up mechanism for the following year DMO cost assessment, or using the Distribution Network Service Provider's (DNSP) annual tariff proposals.

We recognise that being able to account for the other factors that affect annual network tariffs is important and propose the following cost forecast approach is achievable.

- For the DMO Draft Determination:
    - for DNSPs currently within a regulatory period - use the indicative tariffs provided in the approved annual network tariffs
    - for DNSPs undergoing a revenue determination - use the indicative tariffs provided with revised revenue proposals

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57 Submissions to the AER Position Paper from AGL pp. 4-5, Alinta p. 2, Ausgrid pp. 4-5, Meridian/Powershop p. 3.

- For the DMO Final Determination:
    - for DNSPs currently within a regulatory period - use the annual tariff proposal ensuring close consultation with AER network pricing staff
    - for DNSPs undergoing a revenue determination - use the Final Determination changes in revenue.

In its submission Ausgrid points out that using the Ausgrid DMO 1 price risks not passing through the estimated reduction in network costs forecasted in our DMO 1 Final Determination for 2019-20. This forecast reduction in network costs is a consequence of a network revenue over-recovery. Ausgrid argues if we carry forward the DMO 1 price and recalculate network costs based on actual 2019-20 tariffs (which are lower than those calculated for DMO 1), the difference between the original and revised calculation of network costs (due to the over-recovery) then become part of the residual costs of the base cost stack. Residual costs would be adjusted for CPI, but the CPI adjustment may not equate to the downward adjustment in network costs. Because of this, they argue, the reduction in network costs would not be reflected in the DMO price.

Similarly, in its submission to the Position Paper, AGL recommends adjusting the DMO 1 price, particularly in SAPN, to correct for the under-forecasting of the actual tariff changes for 2019-20.

In our Final DMO 1 determination we struck a balance between the policy objectives of reducing unjustifiably high standing offer prices, allowing retailers to recover their costs in serving customers, and providing customers and retailers with incentives to participate in the market. We set the DMO at the mid-point between the median standing offer and the median market offer prices. At that time network costs in the Ausgrid distribution area were expected to fall in 2019-20. We noted in our Final Determination for DMO 1 that any adjustments in the Ausgrid network price forecasts for 2019-20 would set the DMO price at a level similar to average market offers at the time. We noted that incentives for retailers and customers to participate in the market would be severely reduced were the DMO to be set at this level.

In our view, the DMO 1 determination also strikes the right balance for the SAPN distribution zone. For these reasons, the DMO 2 determination updates the DMO 1 determination for changes in cost components without further adjustment.

Given our top-down price approach to DMO 1, to build an index for DMO 2 we firstly need to estimate the proportion of wholesale, network and environmental costs in the DMO 1 price. For the network cost component of the DMO 1 base, our index uses the tariffs in the Ausgrid 2019-20 pricing proposal. We agree with Ausgrid that the difference between the original and revised calculations of network costs (due to the over-recovery) now becomes part of residual costs of the base cost stack.

However, we do not consider it appropriate to adjust downward the residual cost components for the Ausgrid region. Our DMO prices are forward-looking and are not designed to reflect actual costs. The DMO 1 prices were set using the best available information at the time, and we do not consider it appropriate to reset the index based on historical data, nor to undertake ex-post adjustments.

We consider the DMO 1 price an appropriate starting point for our index for Ausgrid as for the other distribution regions. We note most submissions regard the DMO 1 price as having achieved our policy objectives. We also note the DMO is intended to prevent unjustifiably high standing offer prices and provide a safety net for disengaged customers. It is not intended to be an offer customers might seek out. We continue to encourage customers to consider changing retailers to take advantage of cheaper offers. Therefore we propose to retain the DMO 1 price as the starting point for our index.

Our Draft Determination

As mentioned above, for DNSP's within a revenue period, we have considered the indicative network tariffs for 2020-21 from the last available annual pricing proposals. For Ausgrid, Endeavour and Essential Energy indicative network tariffs are available in the approved annual pricing proposals for 2019-20.[58]

For the DNSP's undergoing a revenue determination, Energex and SAPN, they are currently available in the revised pricing proposals published in December 2019 for the network revenue determinations for 2020-25.[59] However, for our final determination, for Energex and SAPN, we consider the final determination changes in revenue are the best available information for network cost forecasts. We note it may still be possible to take into account material network revenue cost-drivers, such as the effect that annual under- or over-recovery of network revenues has on a customer's bill. Additionally, with consultation with the DNSPs currently undergoing a regulatory determination we can understand any non-network cost drivers that may significantly impact network tariffs following the network revenue determination.

The inputs for the network tariffs for the Draft Determination and their sources are given in **Appendix C**.

In summary, in assessing network costs we propose:

- for Ausgrid, not to adjust the DMO 1 price for the impact of the remittal decision on the 2019-20 tariffs
- for Energex and SAPN, to consider changes in annual revenue as the basis for changes in network costs in the Final Determination.

We note in the Energex distribution area the applicable Queensland Solar Bonus Scheme is currently funded by the Queensland government.[60] We do not have

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58 See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/ausgrid-annual-pricing-2019-20; https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/endeavour-energy-annual-pricing-2019-20; https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/essential-energy-annual-pricing-2019-20

59 See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25;https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/energex-determination-2020-25

60 AER-approved Energex Pricing Proposal 2019-20, May 2019.

information to indicate whether the government subsidy will continue beyond 2020. If the funding arrangements were to change such that DNSPs become responsible for recovering costs from their customers before the publication of our Final Determination, we would adjust our assessment to take this into account.

3.4.4 Residual costs and the step change framework (including step changes)

We identify other costs apart from wholesale, environmental and network costs (including retail costs), as residual costs. Retail costs are incurred by retailers to acquire, service and retain customers, including meeting regulatory obligations.[61]

The Draft Determination updates retail costs by calculating DMO 1 residual costs and indexing by change in CPI[62]. We also employ a retail cost step change framework consistent with our Position Paper. This section outlines our Position Paper proposals for retail costs, a summary of the submissions we received and our approach to forecasting these costs for the Draft Determination.

Our Position Paper position

The proposed approach to forecasting retail cost changes in our Position Paper is to identify the residual costs in DMO 1 prices after wholesale, environmental and network costs are deducted, and index these costs by CPI. The residual cost component of DMO 1 prices accounts for all retail costs and by indexing this component of DMO 1 we update retail costs for the DMO 2 price.

We also state we would consider the need for specific adjustments through a proposed step change framework. We proposed using the step change framework as part our assessment of the DMO each year. Any changes made as a result of this framework would remain in place for the determination period. This would allow us to identify changes in retail costs that, in exceptional circumstances, are not accurately reflected by applying a general rate of change adjustment.

Our proposed criteria for step changes in the Position Paper are:

- there is an exogenous change in the retailer operating environment that is mandatory and would be incurred by an efficient and prudent retailer within the DMO determination period
- the change will lead to a material overall change in the retail costs of an efficient and prudent retailer
- the change in retail costs is not compensated in our forecast of other cost elements.

[61] For a more detailed description of our definition of retail costs, see our DMO 2020-21 Position Paper, pp. 37-38.

[62] We calculated the relevant CPI for the DMO 2 time period by averaging the RBA's forecast year to quarter for Dec 2020 and Jun 2021, from the RBA's November 2019 Appendix to the *Statement of Monetary Policy*

In the Position Paper we apply these criteria and explicitly consider retail cost step changes relating to five minute settlement, the Retailer Reliability Obligation and Consumer Data Right (CDR).

Our initial assessment was that none of these new obligations warrants a specific adjustment to the DMO price for the 2020-21 period, though we note that the extension of the CDR to the energy sector was still subject to some uncertainty regarding the scope of data sets and timing. We said we would monitor the rollout of this initiative and decide to make further adjustments to the DMO 2 price in preparing the Draft Determination.

We also asked retailers if they disagree with our assessments, and believe there should be an explicit adjustment, to submit data on the costs associated with implementing the regulatory obligation.

Stakeholder submissions

Overall, stakeholders support our proposed approach for retail costs and use of CPI to forecast changes in the DMO price. They also generally support the step change framework criteria and process. Specific feedback from submissions includes the following.

- The Australian Energy Council and Origin Energy request more detail on the materiality criteria for the step change framework, how costs would be assessed and whether a threshold would be applied.
- The Australian Energy Council and Origin Energy suggest costs imposed by exogenous events such as regulatory initiatives should be considered collectively, not just as individual events.
- Alinta Energy, Origin Energy and Red/Lumo suggest the costs to be incurred by retailers over the 2020-21 period for five minute settlement are significant and a specific adjustment to the DMO price to recognise these costs is warranted.
- Three submissions disagree with the use of CPI to forecast changes in retail costs:
    - QCOSS disagrees with the use of CPI as an index forecasting retail costs from DMO 1 as they believe a different calculation than that used in DMO 1 should be used. QCOSS suggests businesses in a competitive market would increase their productivity which should reduce costs over time and suggests a lower rate of change than CPI should be applied.
    - The Australian Small Business and Family Enterprise Ombudsman (ASBFEO) suggests our analysis of costs should take into account the cross-economy impact of cost increases and affordability issues for consumers and small business and family enterprises
    - Meridian/Powershop suggest CPI does not necessarily reflect the true costs to retailers when implementing innovation and other changes that benefit customers.

We have considered the need for more detail on how we assess costs under the step-change framework, including the information we will have regard to in assessing step changes, and the need for a quantitative threshold as part of the step change framework. We believe it would not be helpful to constrain our analysis in this way given the case-by-case approach we would apply. This is consistent with the AER's approach to step changes in our assessment of forecast operating expenditure which do not use a quantitative threshold.

In relation to the issues raised about the assessment of exogenous events, we can confirm assessments for the step change framework consider the impact of regulatory changes both individually and collectively.

Stakeholders were given an opportunity to respond to our draft assessment set out in the Position Paper and were asked to provide relevant information if they disagree with our assessment. The submissions that raised concerns regarding the costs of five minute settlement did not supply any data in support of their submissions. In preparing this Draft Determination we wrote to these retailers directly and requested data to support a reassessment. One retailer responded with quantitative information on a confidential basis and one retailer responded with a more detailed description of the costs they expect to incur.

Regarding scope and timing of the CDR, there have not yet been any updates from Treasury so we propose to continue monitoring this initiative and consider the need for adjustments as part of the Final Determination if we receive evidence of material changes in costs.

Our Draft Determination

The Draft Determination updates the DMO 1 residual costs for the forecast change in CPI between 2019-20 and 2020-21, and uses a retail cost step change framework consistent with our Position Paper. We have made a minor change in response to stakeholder submissions to clarify that our assessment does include a review of the collective impact of multiple changes.

The criteria for our step change framework are:

- there is an exogenous change in a retailer operating environment that is mandatory and would be incurred by an efficient and prudent retailer within the DMO determination period
- the change(s) will lead to a material overall change in the retail costs of an efficient and prudent retailer
- the change in retail costs is not compensated in our forecast of other cost elements.

As stated in our Position Paper, given there is already an allowance for regulatory costs in the 'costs to serve' component of retail costs, we consider only exceptional circumstances are likely to justify explicitly adjusting the DMO price. While we will consider all information provided to us in this process to undertake assessments, we place greater weight on information providing a transparent and factual representation of actual costs incurred by a retailer, and the proportionality of these costs, resulting from an exogenous change in the retailer's operating environment.

Applying this framework to consideration of the costs of implementing five minute settlement, we assessed the information on costs provided by the retailer who responded to our request for data. The data supplied was not suitable to be solely relied upon as evidence of material costs incurred by retailers, and the costs identified by the retailer were not material. Because of this, there is insufficient evidence to suggest an adjustment to the DMO price is needed. We will consider any further evidence provided in response to this Draft Determination as part of finalising our Final Determination.

The overall change in residual costs by region is set out in Table 10 below:

Table 10: Change in residual costs by distribution area and customer type

Description	Residual cost	Overall change in costs (%)
Residential without CL		
Ausgrid	+1.85%	**+1.1%**
Endeavour	+1.85%	**+0.5%**
Essential	+1.85%	**+0.5%**
Energex	+1.85%	**-5.5%**
SAPN	+1.85%	**-4.4%**
Residential with CL		
Ausgrid	+1.85%	**0.0%**
Endeavour	+1.85%	**+1.2%**
Essential	+1.85%	**+0.3%**
Energex	+1.85%	**-7.6%**
SAPN	+1.85%	**-5.7%**
Small business without CL		
Ausgrid	+1.85%	**-0.3%**
Endeavour	+1.85%	**+0.7%**
Essential	+1.85%	**+0.4%**
Energex	+1.85%	**-6.3%**
SAPN	+1.85%	**-7.6%**

4 Model annual usage and TOU determination

Under Part 3 of the Regulations, we are required to determine 'broadly representative' annual supply amounts for residential and small business customers in each distribution region, from which a DMO price and reference bill can be calculated. In this document we refer to annual supply as annual 'usage'. We must also determine the timing and pattern of supply to residential customers.[63]

Our Draft Determination is to adopt the annual usage amounts from our DMO 1 determination for residential and small business customers. These usage amounts will also apply to customers on solar tariffs and residential customers on TOU tariffs, following anticipated amendments to the Regulations.

Table 11: Draft annual usage determinations 2020-21

Distribution Region	Residential Annual Usage – no CL#	Residential Annual Usage – CL ++		Small Business Annual Usage ^
		General Usage	Controlled Load Usage	
Ausgrid	3,900 kWh	4,800 kWh	2,000 kWh	20,000 kWh
Endeavour Energy	4,900 kWh	5,200 kWh	2,200 kWh	20,000 kWh
Energex	4,600 kWh	4,400 kWh	1,900 kWh	20,000 kWh
Essential Energy	4,600 kWh	4,600 kWh	2,000 kWh	20,000 kWh
SAPN	4,000 kWh	4,200 kWh	1,800 kWh	20,000 kWh

Source: Network distribution businesses' 2019-20 annual pricing proposals

++ Source: Network distribution businesses' 2019-20 annual pricing proposals, with CL assumptions based on the AER's 2017 Energy Consumption Benchmarks

^ Source: Energy Consumers Australia, SME Retail tariff tracker

For timing and pattern of supply:

- consistent with the Position Paper, we apply uniform consumption throughout the year – daily consumption is consistent across the year with no adjustments for seasonality
- we have apportioned 30 per cent of total consumption as CL

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63 Regulations, s. 16(1)(a)(i).

- for TOU customers our draft determination is to set a daily usage allocation for each region and customer type, rather than an annual profile as proposed in our Position Paper. **Appendix F** provides the details of the daily profile for each distribution region.

This chapter discusses our consideration of issues raised by stakeholders in relation to our annual usage, and timing and pattern determinations.

In our DMO 1 determination, we based the residential annual usage on forecast consumption data provided by network businesses. We considered this approach met the criteria of being broadly representative of customer consumption as it:

- identified information specific to residential customers within distribution regions
- was recent, had been subject to quality assurance by the network businesses and had been assessed by the AER in the context of annual pricing approval processes.[64]

To calculate annual CL usage, we applied household usage data collected as part of our 2017 Energy Consumption Benchmark project developed by ACIL Allen[65] to the network consumption data.

We adopted an annual usage of 20,000 kWh for small business customers, consistent with that published by ECA.[66] We considered this was the best source of business consumption data available.

Under the Regulations' reference price provisions, retailers are required to calculate annual bills for TOU offers, to compare their prices to the DMO price. To provide retailers with a consistent basis for calculating annual TOU bills, our DMO 1 Final Determination sets out annual usage allocations for the peak, off-peak and shoulder periods of different TOU tariff configurations in each region.[67] We refer to these allocations in the document as the DMO 1 annual usage allocations.

Our Position Paper position

In the Position Paper we propose using the same annual usage and 'timing and pattern' of supply assumptions as our DMO 1 determination. This includes maintaining the same usage amounts for CL. We considered these were based on the best available information and would provide consistency and certainty for retailers, who were already using them for reference price comparisons.

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64 AER, *Final Determination, Default Market Offer Prices 2019-20*, section 4.

65 ibid.

66 Energy Consumers Australia, *SME Retail Tariff Tacker report*, June 2018. The 20,000 kWh figure is based on a rounded average consumption for small businesses in various NEM by Jacobs Australia for AEMO.

67 AER, *Final Determination, DMO Prices 2019-20*, Appendix H.

As in our DMO 1 determination, we also propose flat consumption (that is, daily consumption is assumed to be the same throughout the year with no adjustments for seasonality).

The Commonwealth Government is considering amending the Regulations to make the DMO price cap apply to residential customers on TOU and solar tariffs for the DMO 2 determination. In particular, it is considering repealing sections that exclude these customers from coverage under the reference price and price cap provisions. Under the proposed revisions, the annual price (i.e. DMO price) and model annual usage we determine for each distribution region will act as the price cap for flat rate and TOU tariff customers. However, the amendments are expected to exclude consideration of solar feed-in tariffs in the annual price.[68]

Regarding TOU tariff customers, the proposed amendments do not provide for us to determine a separate annual price. Our Position Paper therefore considers how a single DMO price and model annual usage determination should take into account TOU tariffs. Our preliminary view was that the model annual usage and annual price developed for flat rate tariff customers were appropriate to use as a price cap for TOU tariff customers. This was on the basis the available evidence suggested TOU and flat rate customers using the same annual amount of electricity have similar bills.

In our Position Paper, for the timing and pattern of supply of TOU, we propose establishing specific kWh usage amounts for peak, off-peak and shoulder periods corresponding to DMO 1 annual usage allocations. Retailers would use these allocations when calculating the annual price of TOU standing offers. Retailers would set their own prices for each period (based on our usage amounts), ensuring the annual bill did not exceed the DMO price cap.

In our Position Paper we recognise the benefits of this approach include:

- consistency and certainty for retailers
- retaining simple comparability of DMO pricing over the two years.

Regarding solar tariff customers, in the Position Paper we note the available evidence indicates overall consumption and annual bills for solar customers are similar to those of non-solar customers. As discussed, the ACCC's REPI final report observes solar customers and non-solar customers use similar amounts of energy from the grid for various reasons.[69] Also, research conducted by ACIL Allen on Victorian customers indicates that, while seemingly counter-intuitive, there is little difference in total consumption of households with solar panels and those without, and that solar customers tend to use more energy overall.[70] On this basis, we consider the usage of a

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68 See: https://www.energy.gov.au/government-priorities/consultations/competition-and-consumer-legislation-amendment-electricity

69 AER *Position Paper Default Market Offer Price 2020-21*, September 2019, p. 53; ACCC, *Retail Electricity Pricing Inquiry – Final Report*, June 2018, p. 26.

70 ACIL Allen Consulting, *Victorian Energy Usage Profiles*, March 2019, p. 33.

non-solar customer is broadly representative of a solar customer for the purpose of the DMO.

Stakeholder submissions

A number of stakeholders support our approach of using the DMO 1 annual usage figures in DMO 2 for flat rate tariff customers, noting benefits of simplicity, consistency and comparability.[71]

For instance, Alinta Energy notes:

> To ensure consumer confidence, simplicity in the assumptions is critical. Consistency across DMO determination periods is also important as it allows for year-on-year comparisons.[72]

In contrast, Meridian/Powershop consider we should undertake further analysis to more accurately estimate loads in an average year.[73]

AGL considers our small business annual usage figure is significantly higher than a typical small business user.[74]

A number of stakeholders do not agree it is reasonable to apply a DMO price cap based on flat rate tariffs to customers with TOU tariffs. Stakeholders have two main concerns:

1. retailers face higher costs for TOU tariff customers compared with flat rate customers, which would not be captured by the flat rate DMO price
2. our assumed timing and pattern of supply, and specifically our allocations of peak, off-peak and shoulder usage do not reflect how retailers incur charges at the network level.

Origin Energy, Red Energy/Lumo, Simply Energy and Ausgrid submitted that under the DMO 1 annual usage allocations, retailers face higher underlying network and metering costs to serve TOU customers than for flat rate customers using the same amount of electricity.

Red Energy/Lumo provide a table showing the combined network fixed and usage charges for a TOU customer are $16 and $147 per year higher than for a flat rate customer in NSW (depending on region).[75] Ausgrid notes in its region, metering charges for TOU customers are $19 more than for flat rate tariffs, while the fixed component of the TOU network tariff is $33 more.

[71] Submissions to the AER Position Paper from AGL p. 5, Alinta Energy p. 2, Origin Energy p. 7, Ausgrid p. 6, EnergyAustralia p. 3.

[72] Submission to the AER Position Paper from Alinta Energy p. 2.

[73] Submission to the AER Position Paper from Meridian/Powershop p. 4.

[74] Submissions to the AER Position Paper from AGL p. 5.

[75] Submission to the AER Position Paper from Red Energy/Lumo p. 4. Figures exclude GST.

Retailers suggest these higher per-customer costs would reduce their ability to recover efficient costs incurred in serving TOU standing offer customers.[76] Red Energy/Lumo suggest the additional network costs incurred by retailers to serve TOU customers will become increasingly material as more customers receive smart meters and go onto TOU tariffs.[77]

Other stakeholders note the usage in the peak, off-peak and shoulder periods of our DMO 1 annual usage allocations are not representative of what a typical residential customer would use during the corresponding network tariff periods.

Ausgrid notes according to its data, around 14 per cent of annual usage occurred during the peak window of its TOU network tariff, compared with around 30 per cent under our DMO 1 annual usage allocation for the Ausgrid region.[78] This difference in annual peak usage was largely due to the structure of Ausgrid's TOU network tariff, which has no peak charges for around seven months of the year.[79]

Some stakeholders note possible unintended consequences for retailers' pricing practices from the misalignment of peak, off-peak and shoulder periods. EnergyAustralia and Ausgrid suggest it may provide incentives for retailers to adopt pricing practices are not in the best interests of customers. For example, Ausgrid notes peak network charges were significantly higher than off-peak and shoulder charges.

The high allocation of peak usage in our DMO 1 annual usage allocation for Ausgrid's distribution area would lead to bills that are higher than the typical annual TOU bill in the Ausgrid area. It notes this may provide retailers with incentives to manipulate daily supply and usage charges primarily to create an annual bill that looks attractive in relation to the reference price. Prices set on this basis may 'dilute' the price signals designed as cost-reflective network tariffs approved by the AER.[80] We explore this issue in more detail below.

EnergyAustralia submitted retailers often apply price signals (that is, the high peak costs and low off-peak costs) designed in network tariffs, which are developed in consultation with consumer representatives, when setting their retail tariffs. Where our annual profile results in a price that appears high in comparison to the reference price, retailers would have incentives to design tariffs to appear low relative to the reference price, regardless of the customer outcome.[81]

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76 Submissions to the AER Position Paper from Origin p. 7, Simply Energy pp. 2-3.

77 Submission to the AER Position Paper from Red Energy/Lumo p. 5.

78 Submission to the AER Position Paper from Ausgrid p. 6.

79 In contrast, the DMO 1 annual profiles assume a 6-hour peak window across 365 days a year. See Appendix J.

80 Submission to the AER Position Paper from Ausgrid p. 7.

81 Submission to the AER Position Paper from EnergyAustralia p. 3.

Some stakeholders suggest different approaches for TOU customers, including:

- setting a separate DMO price for TOU tariff customers.[82] As noted previously, there is no scope for us to do this under the current or proposed amendments to the Regulations
- making allowances for the higher underlying costs in the single DMO[83]
- revising our annual usage allocations to more closely reflect customer usage in each distribution area.[84]

Stakeholders are generally supportive of the single DMO annual usage and price applying to solar customers. AGL considers it is appropriate that DMO prices apply to standing offer customers, regardless of whether they have solar.[85] Origin considers there is no reason to change the price and usage determinations to account for solar customers.[86]

Simply Energy suggests metering costs for solar customers are generally higher than for non-solar customers, and considers we should pass these costs through to the DMO price in each distribution region so the DMO does not impact on retailers' abilities to recover efficient costs.[87]

Powershop considers to mitigate the risk of setting a DMO price that does not take into account different underlying costs for solar customers, we should take a 'conservative approach' and set a higher DMO price.[88]

Our Draft Determination

Our Draft Determination departs from our Position Paper approach in some aspects which are discussed under the relevant headings below.

Annual usage

Consistent with the approach set out in our Position Paper, our Draft Determination is to continue to use the residential and small business annual usage amounts from our DMO 1 Final Determination, including for customers with CL and TOU tariffs.

We acknowledge that while analysis of the most recent network usage forecasts may provide updated annual usage figures, our DMO 1 annual usage amounts remain broadly representative. Our view, supported by many stakeholders, is that using the DMO 1 annual usage figures achieves this purpose, while providing stakeholders with consistency and comparability with the DMO 1 determination.

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82 Submission to the AER Position Paper from Origin Energy p. 7.

83 Submission to the AER Position Paper from Simply Energy pp. 2-3.

84 Submissions to the AER Position Paper from Ausgrid p. 8, EnergyAustralia p. 1.

85 Submissions to the AER Position Paper from AGL p. 6.

86 Submission to the AER Position Paper from Origin Energy p. 7.

87 Submission to the AER Position Paper from Simply Energy pp. 2-3.

88 Submission to the AER Position Paper from Meridian/Powershop p. 5.

In relation to small business customers, we note stakeholder comments about the variability of this cohort and their differing annual usage and we recognise significant challenges around setting a meaningful consumption benchmark given the heterogeneous nature of small business electricity consumption. We have adopted an annual usage figure of 20,000 kWh which we consider is broadly representative of a small business user.

Annual price and timing and pattern of supply

Our Draft Determination, consistent with our Position Paper, is to continue to assume:

- the same usage across the year (with no seasonal differences)
- allocations of total annual CL usage across multiple CL

In light of stakeholder feedback, our Draft Determination uses a 24 hour daily usage profile for each distribution zone. The profile shows electricity usage in each of the 24 hours of the day for TOU tariffs. Retailers can use this daily profile to calculate their own peak, off peak and shoulder allocations when determining their standing offer TOU prices.

To arrive at this decision we undertook further analysis of two key matters raised by stakeholders. These are:

- analysis of network costs and TOU offer prices to understand retailers' concerns that higher metering and network costs for TOU customers mean they are more expensive to serve than flat rate customers
- our annual usage allocations.

These are discussed in the remainder of this chapter.

TOU metering and network charges

Metering charges

Network metering service charges form part of distribution businesses' annual pricing proposals and are approved by the AER.

Our analysis of businesses' approved metering costs indicates that while there are higher annual network metering charges for TOU customers in some distribution areas, this is not the case in all areas. For instance:

- in Ausgrid's distribution area, TOU metering charges for 2019-20 are around $19 (excluding GST) per year higher than for flat rate customers[89]

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[89] AER Final Decision, Ausgrid Distribution Determination 2019-24, April 2019, Attachment 15 p. 32. https://www.aer.gov.au/system/files/Ausgrid%20-%20AER%20approved%202019-20%20Initial%20Pricing%20Proposal%20-%20REVISED%20-%2029%20May%202019%20-%20June%202019.pdf

- in Endeavour Energy's distribution area, TOU metering charges are around $21 higher than for flat rate customers[90]
- in Essential Energy's distribution area, TOU metering charges are around $16 higher than for flat rate customers[91]
- in Energex's distribution area, there is no difference in metering service charge between TOU and flat rate customers.[92]

SAPN has no current TOU metering charges, but the proposed charges under its 2020-25 Regulatory Proposal indicate no difference between flat rate and TOU charges.[93]

Fixed network charges

Network businesses' TOU and flat rate tariff pricing (that is, what electricity retailers pay to transport electricity) is approved by the AER each year. Network prices typically have a fixed daily charge, as well as a per kWh usage charge.

Our analysis of the fixed component of network businesses' approved tariffs shows the charges are higher for TOU customers than for flat rate customers in some, but not all, areas. For instance:

- in Ausgrid's network region, fixed network charges for 2019-20 are $32 per year higher than for flat rate customers[94]
- in Endeavour Energy's region, fixed network charges are $13 per year higher than for flat rate customers [95]
- in Essential Energy and Energex's regions, there is no difference in fixed network charges between TOU and flat rate customers.[96]

SAPN has no current TOU tariffs.[97]

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90 AER Final Decision, *Endeavour Energy Distribution Determination 2019-24*, April 2019, Attachment 15, p. 42.

91 AER Final Decision, *Essential Energy Distribution Determination 2-019-24*, April 2019, Attachment 15, p. 51. https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/essential-energy-annual-pricing-2019-20/proposal

92 Energex, 2019-20 Network Tariff Tables update for Sch8 prices. https://www.energex.com.au/__data/assets/excel_doc/0011/760484/2019-20-Network-Tariff-Tables-updated-for-Sch8-prices.xlsm

93 SA Power Networks, *2020-2025 Revised Regulatory Proposal,* December 2019, Attachment 17.

94 Ausgrid, *Pricing proposal for the financial year ending June 2020*, May 2019, p. 26.

95 Endeavour Energy, *Pricing Proposal*, 1 July 2019-30 June 2020, p. 78.

96 Essential Energy, *Annual pricing 2019-20, Attachment 5*; Energex, Annual pricing 2019-*20*, April 2019, Attachment 1.

97 SAPN, *2020-25 Revised Regulatory Proposal*, December 2019, Tariff Structure Statement Part A, p. 38.

Network usage charges

Network usage charges for TOU customers vary depending how much is assumed to occur in peak, off-peak and shoulder periods – that is, the usage allocation.

Some stakeholders note the usage amount in each period of our DMO 1 annual profile differs from what a typical user would consume in the corresponding network tariff periods.

To understand the impact of our DMO 1 annual usage allocations on network charges in all network distribution areas, we compared network usage costs for flat rate tariff customers in each distribution area to network usage costs for TOU customers under our DMO 1 annual usage allocations.

Noting stakeholders' comments about our DMO 1 annual usage in each period not being representative of a typical customer due to different network tariff structures, we also analysed network charges with usage allocations aligned to the periods in each area's approved TOU network tariff.[98]

Table 12 compares network usage charges for flat rate customers in each region with those for TOU customers. It shows network usage charges for TOU customers under our DMO 1 annual period allocations are:

- higher than for flat rate customers in the Ausgrid, Energex and Endeavour Energy regions (when comparing Endeavour's two-period seasonal TOU tariff prices)
- lower than under SAPN's proposed 2020-21 TOU network tariff pricing
- around the same in Essential Energy and Endeavour Energy's areas (when comparing Endeavour's three-period TOU tariff prices).

In contrast, under the alternative period allocations aligned to the TOU network tariff period in each area, network usage charges were around the same level as for flat rate customers, or slightly lower.

This analysis shows that the higher network usage charges for TOU customers raised by some stakeholders are due to the DMO 1 usage allocations, rather than a fundamental difference in cost structures. It also illustrates that usage allocations mirroring network tariff structures mitigate price discrepancies.

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98 This was calculated by converting the DMO 1 period allocations into a daily profile of hourly usage blocks. To determine annual usage in the peak, off-peak and shoulder periods of the approved TOU network tariff, we added the hourly usage in these windows over 365 days. This methodology is illustrated in Appendix E. [98]

Table 12: Network usage charges comparison, flat rate and TOU (GST inclusive)[99]

Distribution Region	Annual network usage charges – flat rate	Annual network usage charges – TOU (DMO 1 usage allocation)	Annual network usage charges – TOU (network tariff-aligned profile)
Ausgrid 3,900 kWh/yr	$332.20	$479.19	$318.29
Essential 4,600 kWh	$523.69	$523.34	$433.15
Endeavour 1 4,900 kWh	$454.08	$511.72	$457.41
Endeavour 2 (2-period seasonal) 4,900 kWh	$454.08	$812.99	$429.79
Energex 4,600 kWh	$426.25	$517.97	$433.73
SAPN 4,000 kWh	$626.56	$437.31	$586.68

We see a similar effect when comparing a median flat rate market offer bill with the median market offer calculated using:

- the DMO 1 annual usage allocations
- network-aligned allocations.

This is demonstrated in Table 13 that shows the median TOU market offer bill calculated using the DMO 1 profile is higher than the median flat rate market offer in each area. In contrast, median market offer bills calculated using the network tariff-aligned usage allocation are similar or slightly lower than the median flat rate market offer.

99 The figures are based on currently approved network TOU tariff pricing in place for 2019-20. SAPN has no current TOU network pricing. The SAPN figures in this table are based on pricing proposed in its 2020-25 Regulatory Proposal – see https://www.aer.gov.au/system/files/SAPN%20-%20Revised%20Proposal%20-%20Attachment%2017%20-%20Tariff%20Structure%20Statement%20Part%20A%20-%20December%202019.pdf

Table 13: Median annual market offer price, flat rate and TOU[100]

	Median market offer bill – flat rate	Median annual ma bill – TOU (DMO 1 annual profile)	Median annual bill – TOU (network tariff-aligned profile)	2018-19 DMO price
Ausgrid	$1,317	$1,384	$1,252	$1,467
Endeavour	$1,542	$1,664	$1,395	$1,720
Essential	$1,758	$1,804	$1,672	$1,957
Energex	$1,409	$1,472	$1,396	$1,570
SAPN[101]	NA	NA	NA	$1,941

Having considered stakeholder submissions and analysed retailers' relative costs to serve TOU and flat rate customers, we do not consider differences, where they exist, are sufficiently material to warrant increasing the DMO price to accommodate these costs. Our view is that the DMO price is sufficient to accommodate these differences in costs without impacting retailers' abilities to recover efficient costs for TOU customers. We note the DMO price is still above the median TOU market offer, which is our proxy for a retailer's efficient costs.

Additionally, we consider the revenue impact on retailers of these cost differences is not likely to be material due to the relatively small number of customers on TOU standing offer tariffs. We acknowledge the impact will become more material as more customers move to these tariffs. We will need to monitor this in the future.

Table 14 shows TOU standing offer customer numbers for Tier One retailers in DMO areas, as at October 2019.[102]

100 TOU annual bills have calculated using EME's affordability reporting functionality and are indicative only.

101 There are no TOU offers in the SAPN area from which to calculate median bills.

102 Information provided to AER by retailers.

Table 14: Tier One retailers' residential TOU standing offer customer numbers

	No. TOU SO customers – Tier 1 retailers
Ausgrid	29,112
Endeavour	7
Essential	8,829
Energex	54
SAPN	4
Total	**38,006**

Source: Information provided to the AER by Origin Energy, EnergyAustralia and AGL, October 2019

As discussed, the amounts of annual peak, off-peak and shoulder usage under our DMO 1 annual profiles in some areas are not representative of what a typical residential customer would use in the corresponding network tariff periods. This is largely due to differences between the assumed tariff structure of the DMO 1 annual profile and that of approved network tariffs. In some cases, these differences lead to DMO profiles having a comparatively high peak allocation (for example, in Ausgrid's area) in comparison to the network tariff, and comparatively peak tariff in others (for instance, SAPN).[103]

The TOU network tariff structure is relevant as the basis for retailers to set their TOU prices. Even if their retail tariff periods do not match network tariff periods, their pricing reflects their assumptions about how much a typical customer would consume during each network TOU period.

We recognise that requiring retailers to use a fixed profile that diverges from the network profile when setting standing offer prices may have various consequences.

Daily profile for TOU

Having considered stakeholder submissions and undertaken further analysis, we recognise that setting annual allocations for peak, off-peak and shoulder periods for TOU tariffs as we proposed to do in our Position paper, may have unintended consequences. In particular, if retailers' pricing periods for peak, off-peak and shoulder periods differ from our proposed profile it may require retailers to set higher or lower prices than they otherwise would have done.

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103 Appendix J shows differences TOU network tariff structures for each area.

Table 15 illustrates this point. It shows two scenarios where a retailer could price offers to comply with the annual DMO price cap for Ausgrid ($1,467). Scenario A shows possible pricing under the DMO 1 annual usage allocations, as proposed in our Position Paper. Scenario B shows possible pricing under an alternative annual usage profile aligned to network tariffs. This alternative profile has a lower peak usage.

As demonstrated, the DMO 1 usage allocations require retailers to set lower prices overall, to counter the higher peak weighing, in order to comply with the price cap. Lower peak energy prices may undermine the price signals provided in cost-reflective network tariffs. For example, the specified amount for peak usage in DMO 1 is lower in some areas than the amount for peak usage allowed for in the network aligned profile. In this case, our profile would not have the same effect of limiting retailers' pricing.

The introduction of cost-reflective tariffs is a significant market reform in the long-term interests of consumers. It aims to reduce network costs that are ultimately passed through to retail customers. Long-term beneficial outcomes for customers of these reforms are that retailers will have the scope and incentives to innovate and invest in their market offerings.

Having considered stakeholder submissions and evidence, we are persuaded that establishing fixed annual amounts for peak, off-peak and shoulder usage may restrict retailers' scope to innovate and invest. A further risk of fixed usage allocations that do not represent retailers' actual peak, off-peak and shoulder periods is that TOU offers may appear more attractive in comparison to the reference price in some regions, and less attractive in others. Because of this discrepancy customers may be discouraged from taking up TOU offers in some areas. Accordingly, we do not intend to require retailers to use specified annual kWh amounts as a basis for calculating TOU standing offers as proposed in our Position Paper.

Table 15: DMO standing offer pricing scenarios, high and low peak usage allocations

	Scenario A – DMO 1 usage allocations			**Scenario B – network-aligned profile**		
	kWh/yr	Price	$/year (DMO Price $1,467)	kWh/yr	Price	$/year (DMO Price $1,467)
Daily	*365*	*1.00*	*365*	*365*	*1.00*	*365*
P	1244	0.51	634.44	519.6	0.59	306.56
OP	1115	0.10	111.50	1908.8	0.18	343.58
Sh	1540	0.23	354.20	1471.6	0.30	441.48
			1,465.14			**1,456.63**

Daily usage profile

In the context of the DMO 2, a usage profile enables retailers to determine customer usage over given periods. For example, for a TOU tariff with a peak period of 5pm-9pm during summer, the amount of peak usage occurring in that window each summer day is summed to calculate annual peak usage.

In this Draft Determination we have adopted a daily profile specifying the amount of energy a customer would use during each hour of the day over a 24 hour period, in each distribution region, without designating particular times as peak, off-peak and shoulder periods. **Appendix E** shows how we calculated the daily profile for each distribution region. This provides retailers with the flexibility to determine how to apportion annual usage for each period (i.e. peak, off-peak and shoulder), when setting their standing offer tariff prices. The retailers would still need to comply with the DMO prices. For example, it provides the flexibility to enable retailers to align their usage with network TOU tariff structures.

In our view, the flexibility afforded by the daily usage allocation is consistent with the DMO policy objectives of not dis-incentivising innovation, investment or market participation. It provides retailers with flexibility to set the structure of standing offer TOU tariffs to meet their customers' needs. For example, it allows a retailer to set a standing offer TOU tariff with peak, off-peak and shoulder usage periods corresponding to network tariff windows. It can also more flexibly accommodate tariffs that diverge from the traditional weekday evening peak, weekend off-peak structure, for example, Ausgrid's seasonal TOU tariff, and Endeavour Energy's two-period seasonal TOU tariff.[104]

To develop the daily usage allocations we referred to the daily amount of peak, off-peak and shoulder usage we calculated for the DMO 1 annual usage allocations. We broke this down into hourly usage for each period based on the TOU timing assumptions developed in the Energy Consumption Benchmarks.[105] We consider this remains the best available information and approach to setting the daily usage allocation.

In developing this approach, we also considered other approaches to setting the timing and pattern of supply. For example, we considered setting revised annual profiles, aligned with network tariff windows. While this approach would be appropriate for retailers wanting to set tariffs that match network tariff structures, not all retailers want to do so. Also, we do not consider this approach suitable for tariffs that diverge from traditional structures. We do not consider revised annual profiles would achieve the DMO policy objectives as effectively as the daily profile approach we are proposing in this Draft Determination.

[104] See Appendix J.

[105] These assume peak usage 2-8 pm every day, off-peak usage 10pm-7am, shoulder usage 7am-2pm, 8pm-10pm.

We recognise the daily profile approach will require additional steps for retailers to calculate annual usage for each period. As the profiles are derived using a simple conversion of our DMO 1 annual usage allocations, we regard them as providing transparency and consistency.

For more information on how the daily profiles have been calculated and a worked example of how they could apply in the context of the DMO price, see **Appendices D and E.**

Annual price and model annual usage – solar customers

We do not consider it is necessary to increase the DMO price to accommodate different costs for solar customers.

Our analysis of metering charges in the five distribution areas where the DMO applies, indicates there is:

- no difference in metering costs for solar and non-solar customers in SAPN and Essential distribution areas
- a $25 difference in Energex's distribution area
- a $12 difference in Ausgrid's distribution area
- a $6 difference in Endeavour Energy's area.

We note that retailers face these higher costs for small business customers, as well as residential customers.

Our view is that the DMO price is sufficient in each area to accommodate these differences in costs without impacting on retailers' abilities to recover efficient costs for solar customers.

Appendices

Appendix A – List of submitters to AER Position Paper

Appendix B – Market offer analysis for each distribution region

Appendix C – Forecast changes in cost components

Appendix D – Time of use worked example on the application of a daily consumption profile

Appendix E – Calculation of hourly usage from the DMO 1 annual profile

Appendix F – Time of use hourly consumption profiles

Appendix G – Controlled Load annual usage allocations

Appendix H – List of annual bill calculation assumptions

Appendix I – Network TOU tariff structures

Appendix J – Draft legislative instrument

A List of submitters to AER Position Paper

1. Australian Energy Council (AEC)
2. AGL Energy
3. Alinta Energy
4. Australian Small Business and Family Enterprise Ombudsman (ASBFEO)
5. Ausgrid
6. Energy Consumers Australia (ECA)
7. EnergyAustralia
8. Meridian Energy Australia, Powershop Australia
9. Origin Energy
10. Public Interest Advocacy Centre (PIAC)
11. Queensland Council of Social Service Inc (QCOSS), Etrog Consulting
12. Red Energy, Lumo Energy
13. Simply Energy

B Market offer analysis for each distribution region

As the agency responsible for determining DMO prices each year, we consider it necessary to understand any DMO-related impacts so they can inform our future DMO price determinations. The purpose of this analysis is to provide a snapshot of how the market has moved immediately following the DMO's introduction.

We provided an early analysis of the market in the AER's report *Affordability in retail energy markets September 2019*.[106] The market was adjusting to a series of new requirements including the DMO, electricity benchmark bills for customers and new requirements on advertising. Our analysis looks at prices of retailers' publicly available offers to understand what happened to standing offers and market offers following the introduction of the DMO prices on 1 July 2019.

The price analysis is a useful indicator of the market's response to the DMO, highlighting potential trends to monitor, as well as evidence of significant market changes – for example, regarding discounting practices.

We consider it is too early to draw conclusions about the impact of the DMO from this preliminary analysis. In a dynamic market, we expect electricity retailers to respond to competitors by adapting their offerings and pricing, and changes would become apparent over a longer period of time.

In the longer term, we will be looking at metrics in addition to observed prices to understand if and how the DMO has influenced the market, such as changes to retailer market share, numbers of customers on standing offers, levels of competition between retailers, retailers entering and leaving the market, and levels of customer engagement.

For consistency and comparability, the charts and pricing analysis in this section use the same annual usage as used in our DMO Determination. For residential customers, we determined annual usage using average consumption data provided by the network distribution businesses. These benchmark figures vary between different areas. For small business customers, the annual usage is 20 000kWh.

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106 AER, *Affordability in retail energy markets September 2019*, 5 September 2019, Appendix B.

Preliminary observations

B.1 Standing offers

The Regulations require that retailers' standing offer prices must not exceed the DMO price for a network distribution region and customer type.

In practice, this means retailers whose standing offer prices were above the DMO price (more than 90 per cent of retailers in most areas) reduced these prices to the level of the DMO price or lower from July 2019. In our Final Determination for DMO 1 we highlighted that for residential customers (using the benchmark consumption level), the annual bill reductions from moving from the median standing offer to the DMO price were approximately:

- In NSW:
    - $129 in Ausgrid's network distribution area
    - $175 in Endeavour Energy's area
    - $181 in Essential Energy's area
- $118 in south-east Queensland (Energex)
- $171 in South Australia (SAPN).

For small business customers on the benchmark consumption level, annual median savings were approximately:[107]

- In NSW:
    - $878 in Ausgrid's network distribution area
    - $579 in Endeavour Energy's area
    - $709 in Essential Energy's area
- $457 for South-Eastern Queensland (Energex)
- $896 for South Australia (SAPN).

B.2 Market offers

This section looks at changes to highest, lowest and median market offer prices before and after the introduction of the DMO on 1 July 2019.

It shows these changes at three points in time:

- October 2018 – the same data that informed our DMO Final determination. The offers in this dataset preceded the announcement of our DMO
- June 2019 – immediately before the introduction of the DMO

[107] As at October 2018.

- 31 December 2019 – six months after the introduction of the DMO.

Figures B.1 to B.5 below show these movements in graph form. These five charts show the residential flat rate customer offers from EME.

Figure B1: Changes in market offer prices in Ausgrid's region

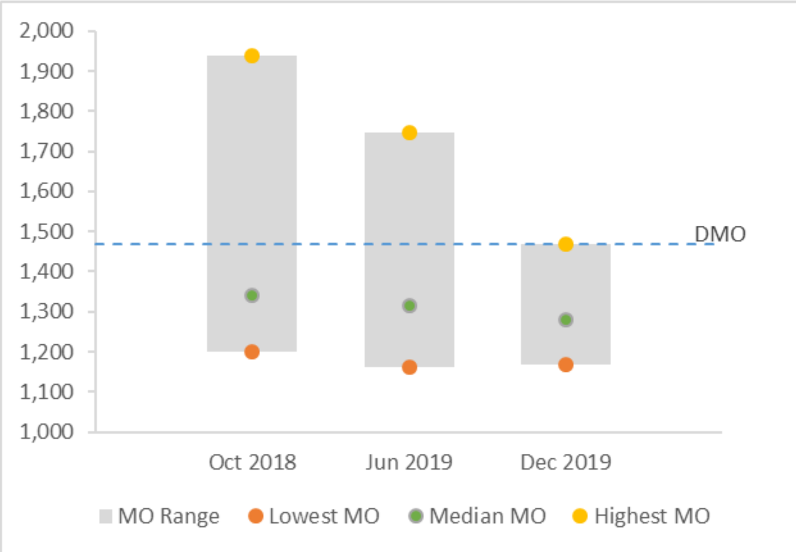


Figure B2: Changes in market offer prices in Endeavour Energy's region

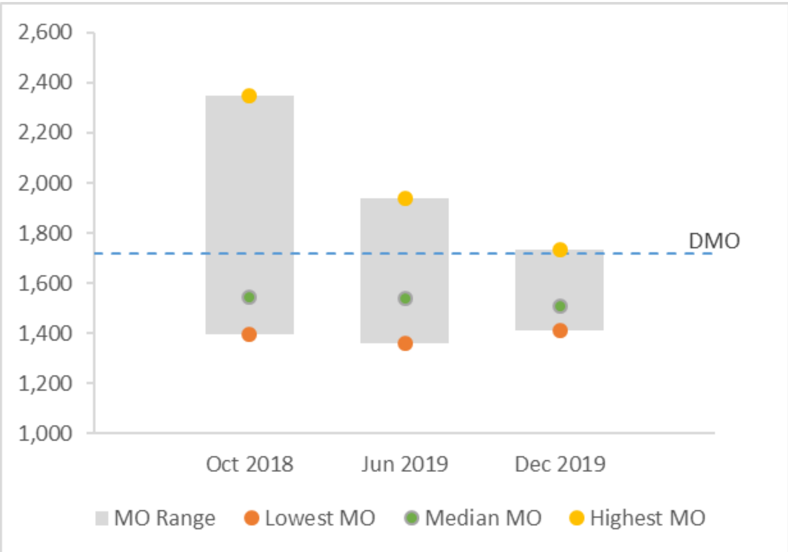


Figure B3: Changes in market offer prices in Essential Energy's region

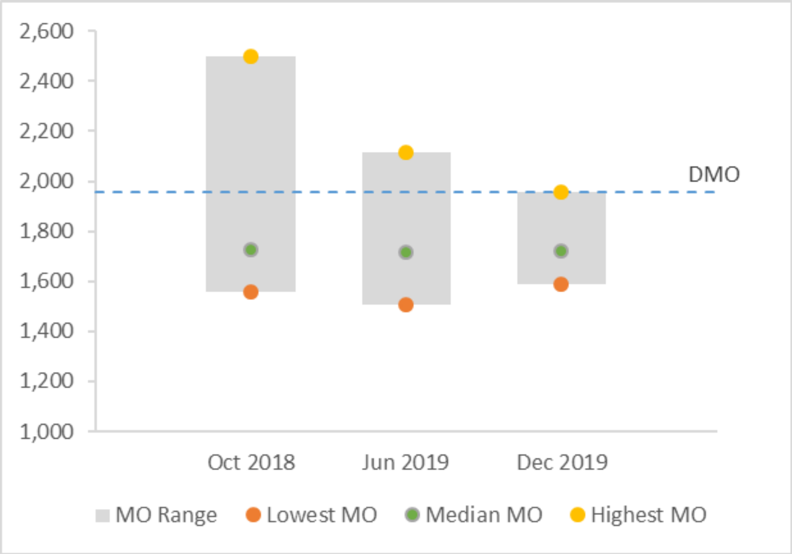


Figure B4: Changes in market offer prices in Energex's region

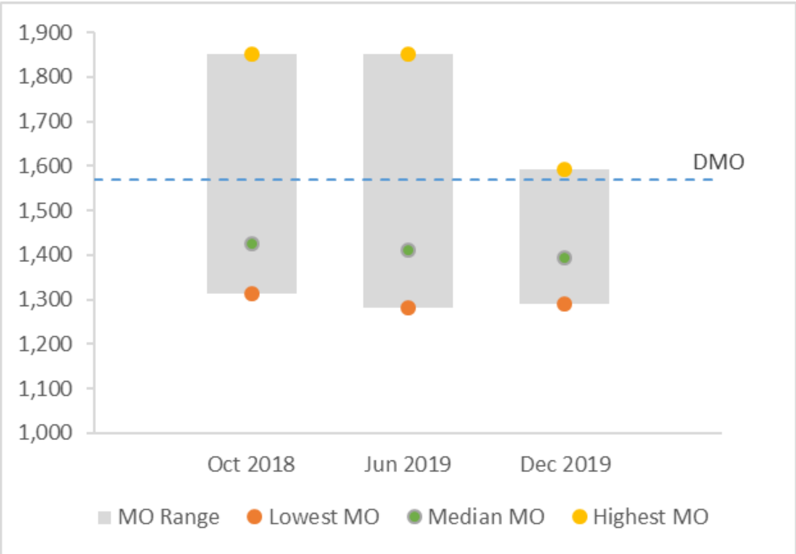
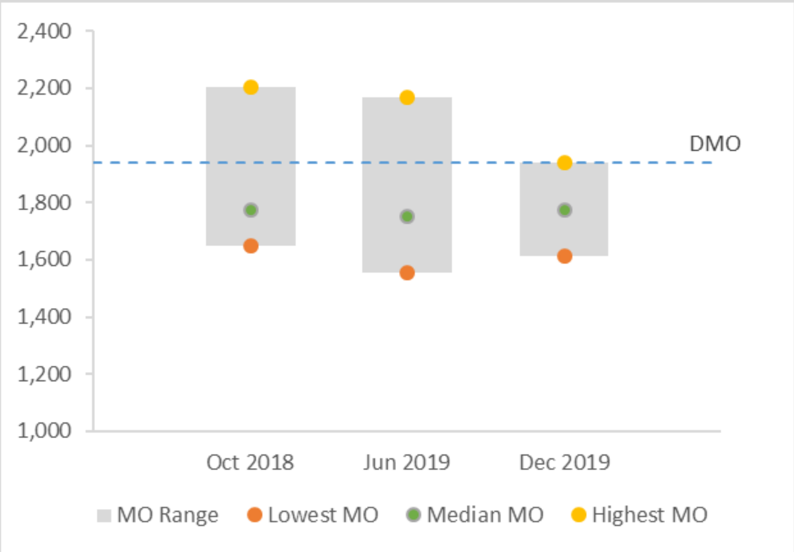


Figure B5: Changes in market offer prices in SAPN's region



Slightly different trends emerge in the comparisons between October 2018 and December 2019, and June 2019 (immediately before the DMO introduction) to December 2019.

Overall median market offers have remained relatively constant, on the whole decreasing. From October 2018 to December 2019, the change in median market offers across the distribution regions ranged from a reduction of 4.5 per cent to a marginal increase of 0.1 per cent.

The spread shown in June 2019 may reflect different pricing strategies by retailers reacting early in anticipation of DMO changes. Our analysis considers trends from October 2018, which pre-dates the publication of our DMO methodology and therefore is not influenced by any DMO-related retailer strategies. We also review the price changes made just before the DMO came into effect.

We also note that from 1 July 2019, network prices increased in some areas (Essential and SAPN) but reduced or remained flat in all other areas. Network charges form a major component of retail pricing (accounting for around 40 per cent of a retail bill), and retail price changes may be explained in part by changes in these costs.

Overall, the trends suggest retailers used the introduction of the DMO to rationalise their range of market offers and, in many cases, simplify their offerings by moving away from conditional discounts. We will continue to monitor these changes over the longer term.

Highest priced market offers

The highest residential market offer for all retailers in December 2019, was lower in all areas in comparison to the highest residential market offers in October 2018.

For residential flat market offers, these reductions generally occurred between October 2018 and June 2019, then a further reduction occurred from June 2019 to December 2019. The exception to this trend was in Energex's area, where the highest offer remained constant between October 2018 and June 2019.

For small business offers, between October 2018 and December 2019, the highest small business market offer decreased significantly in all distribution regions. This trend is observed from June to December 2019 when all retailers' highest market offers decreased by 9 to 15 per cent.

Lowest priced offers

Each retailer's lowest residential flat rate offer decreased from October 2018 and December 2019 by up to 3 per cent in Ausgrid's, Energex's and SAPN's distribution areas. They increased 1 to 2 per cent in Endeavour's and Essential's areas.

For residential flat rate tariffs with CL, the lowest offer remained the same or increased by up to 5 per cent for all retailers. Business customers' lowest offers increased in Essential's and Endeavour's distribution areas and decreased in the other areas.

Median market offer price

The median market offer price did not change significantly between October 2018 and December 2019 across all retailers and areas. Over this period the changes ranged from a reduction of 4.5 per cent to an increase of 1 per cent for residential offers (flat rate and flat rate with CL). Generally, median market offers also reduced between June and December 2019.

Between October 2018 and December 2019, Tier one retailers' median market offers reduced by up to 7 per cent for residential customers. For small business offers, the median market offer reduced by 4 to 6 per cent between October 2018 and December 2019.

Highest, lowest and median market offer changes, Oct 2018-Jul 2019 – by distribution region

Figure B7: Market offer annual bill of all retailers for residential flat rate (including all discounts) in Ausgrid's region

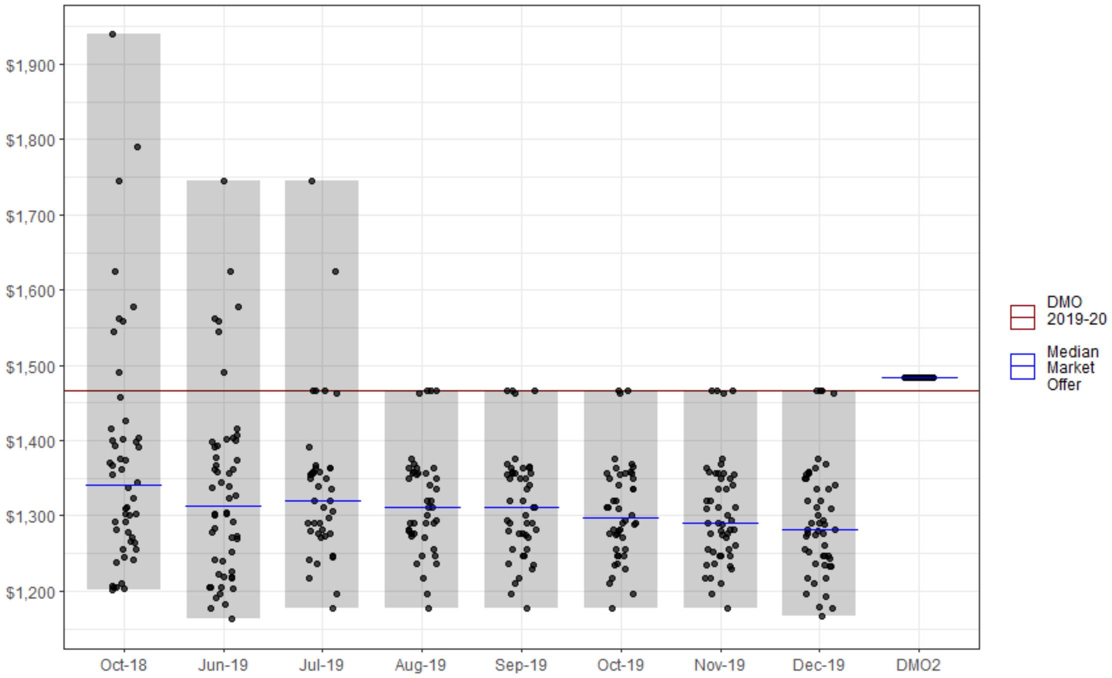


Figure B8: Market offer annual bill of all retailers for residential flat rate (including all discounts) in Endeavour Energy's region

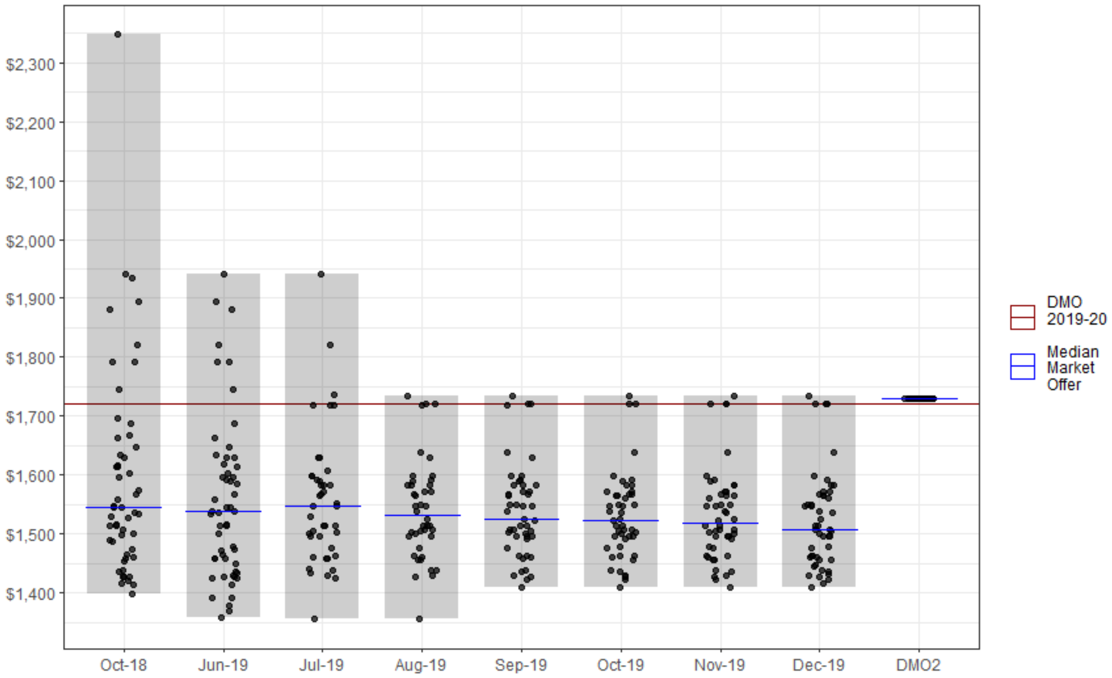


Figure B9: Market offer annual bill of all retailers for residential flat rate (including all discounts) in Energex's region

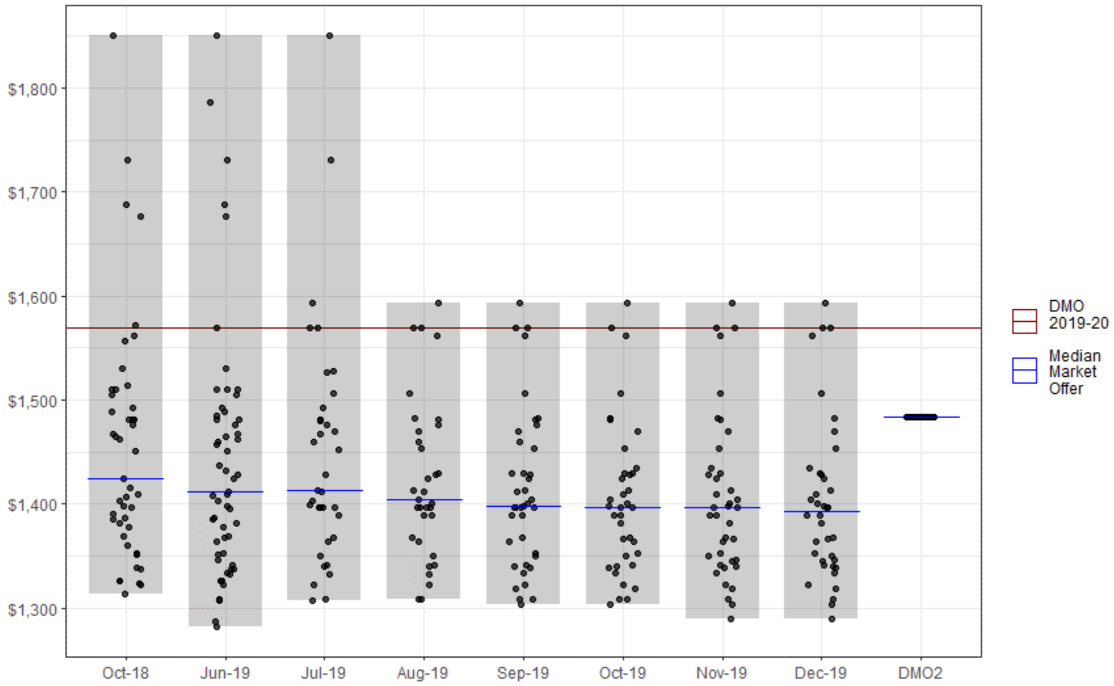


Figure B10: Market offer annual bill of all retailers for residential flat rate (including all discounts) in Essential Energy's region

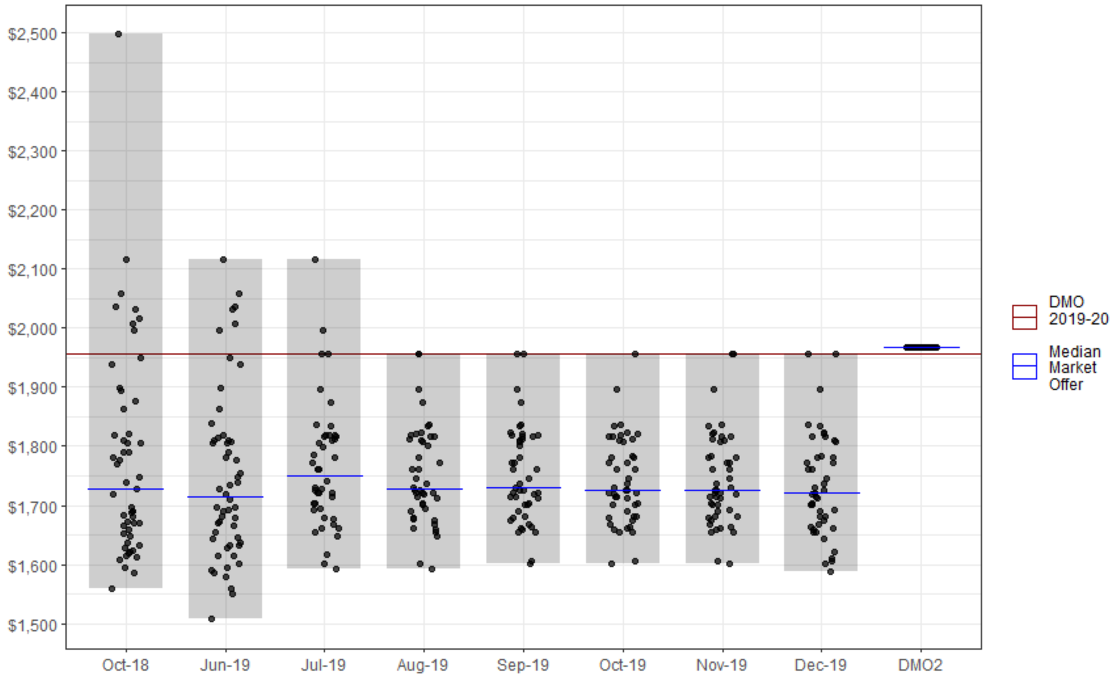


Figure B11: Market offer annual bill of all retailers for residential flat rate (including all discounts) in SAPN’s region

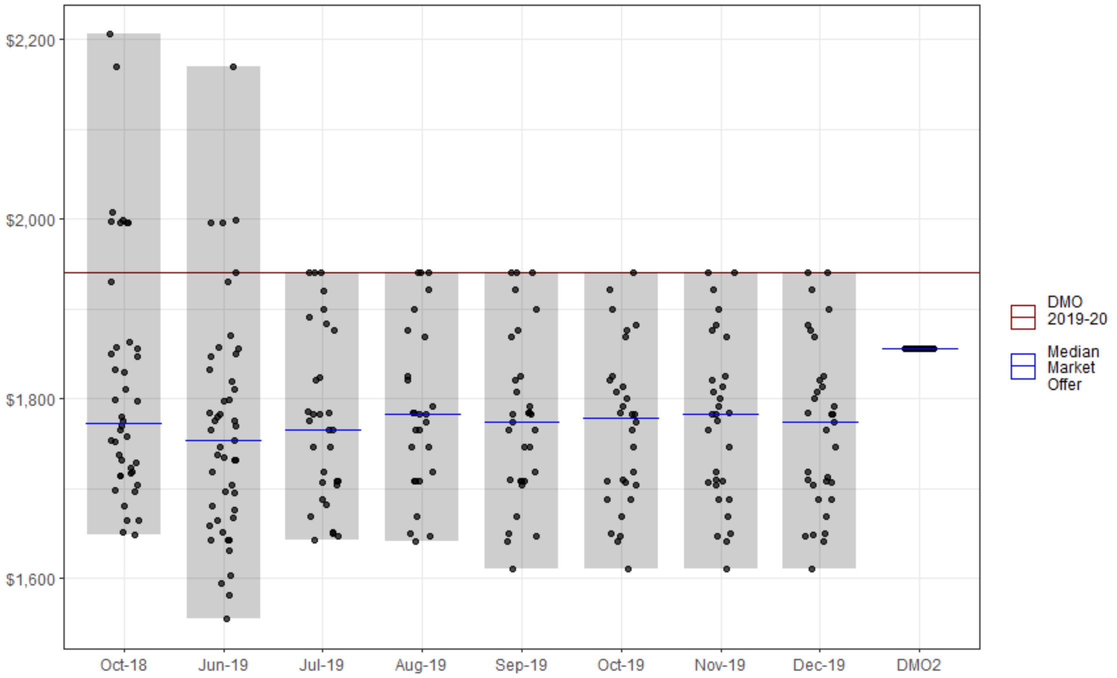


Figure B12: Market offer annual bill of all retailers for residential controlled load (including all discounts) in Ausgrid’s region

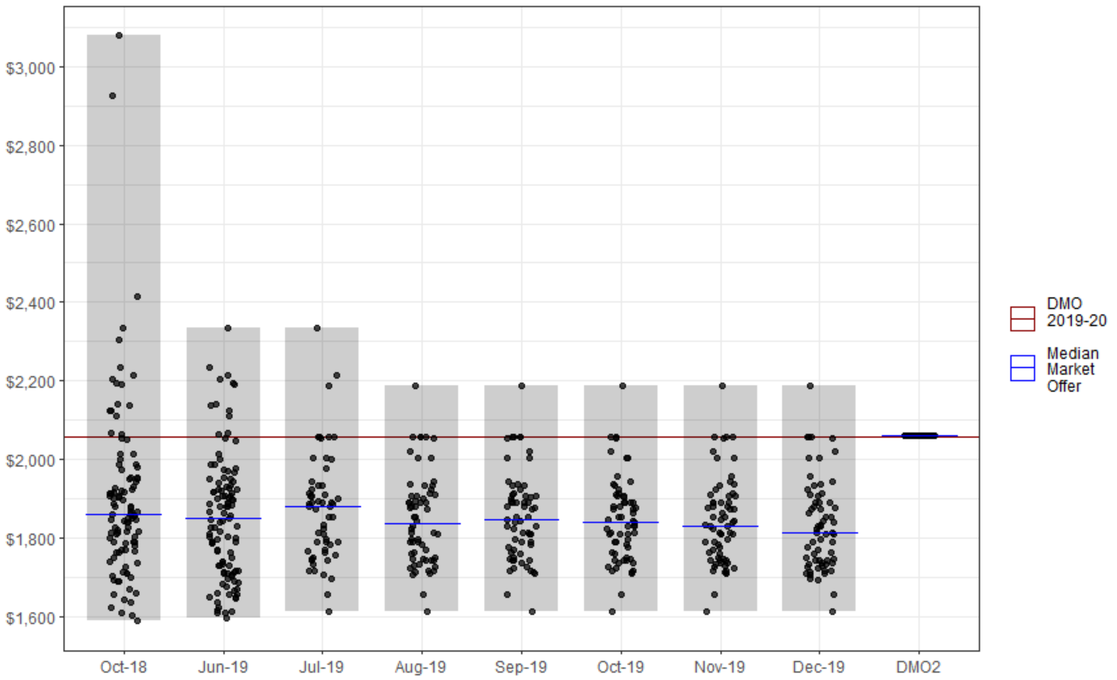


Figure B13: Market offer annual bill of all retailers for residential controlled load (including all discounts) in Endeavour Energy's region

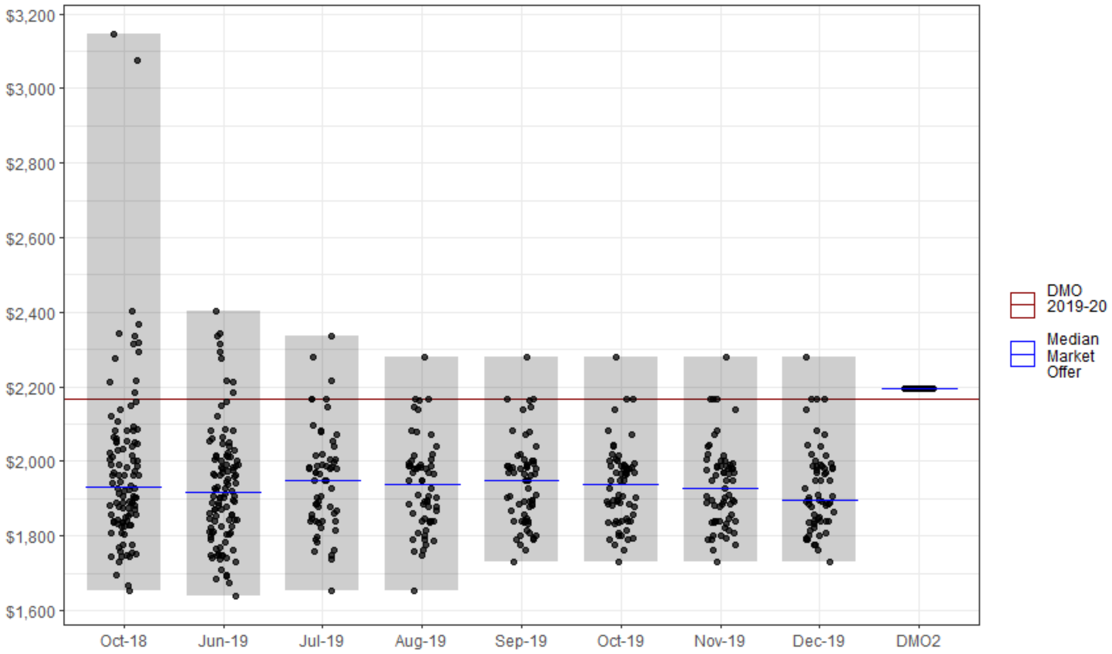


Figure B14: Market offer annual bill of all retailers for residential controlled load (including all discounts) in Energex's region

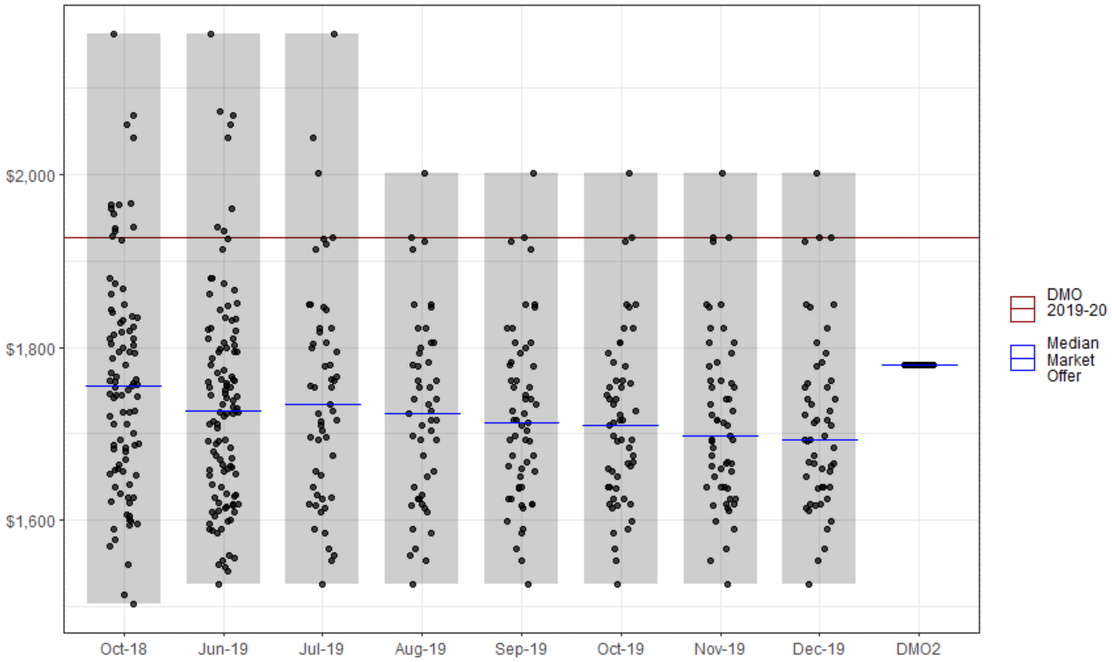


Figure B15: Market offer annual bill of all retailers for residential controlled load (including all discounts) in Essential Energy's region

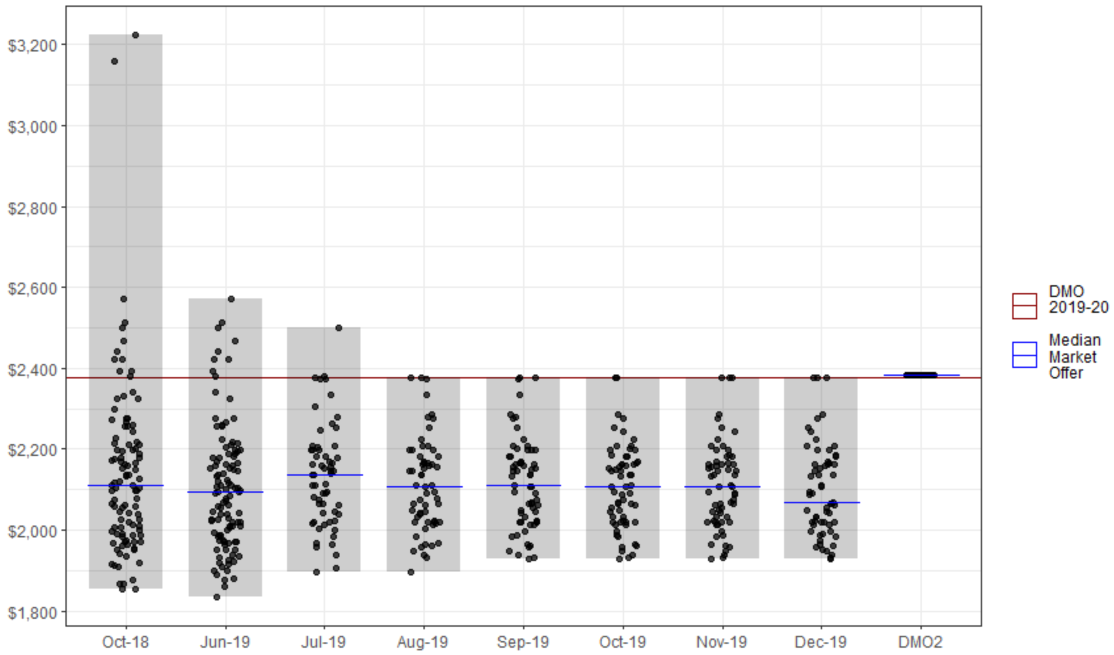


Figure B16: Market offer annual bill of all retailers for residential controlled load (including all discounts) in SAPN's region

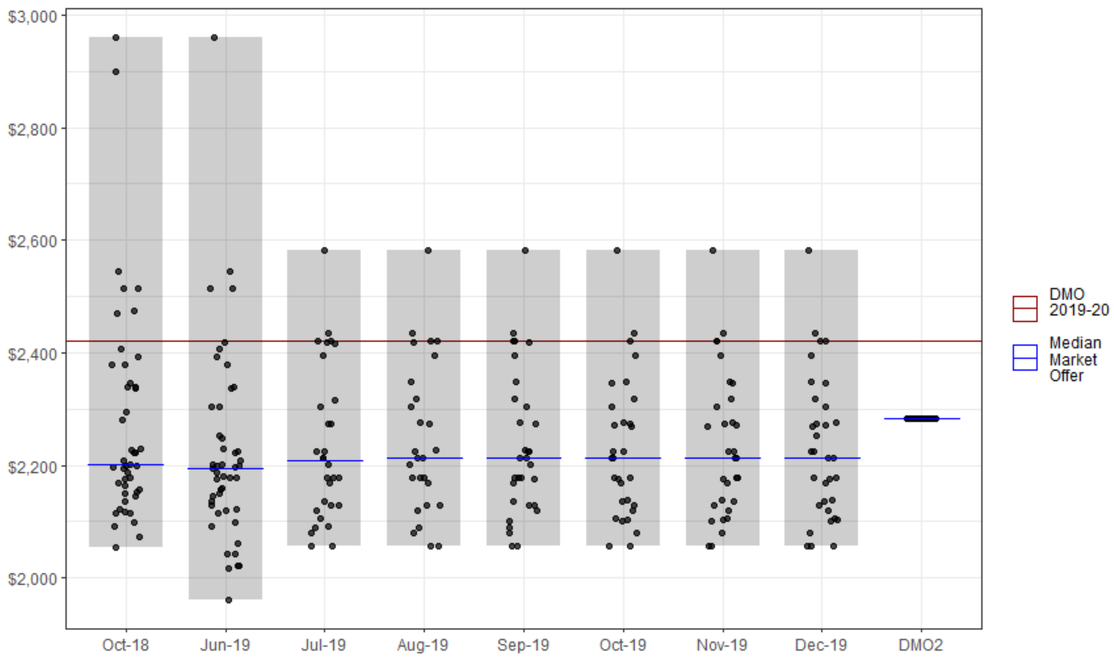


Figure B17: Market offer annual bill of all retailers for SME (including all discounts) in Ausgrid's region

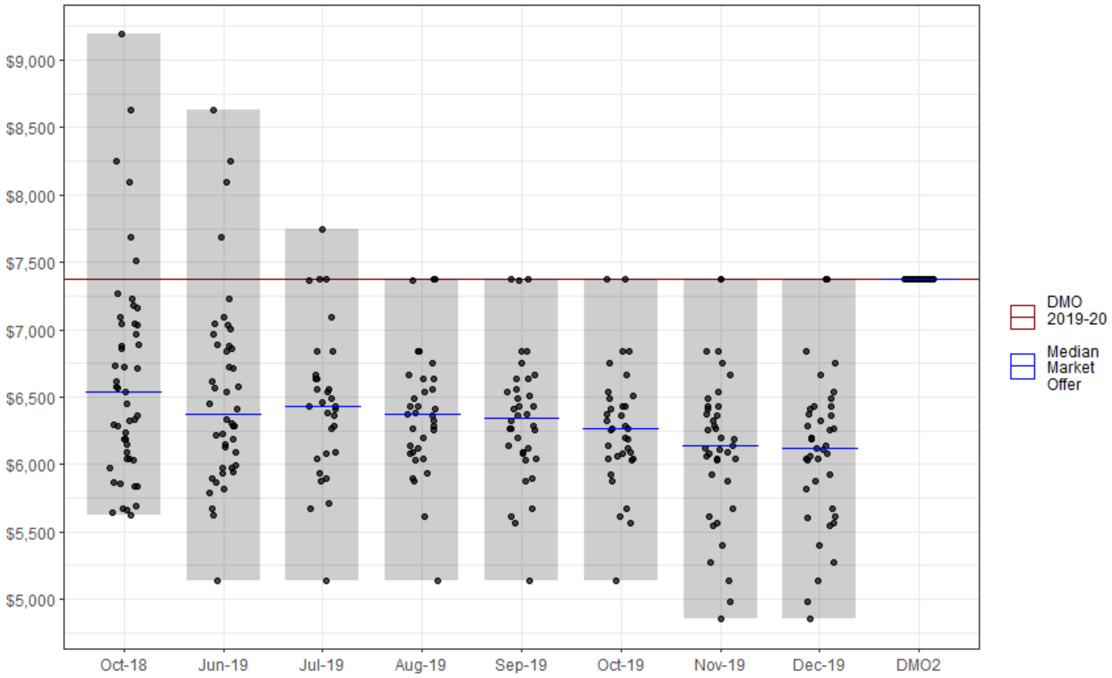


Figure B18: Market offer annual bill of all retailers for SME (including all discounts) in Endeavour Energy's region

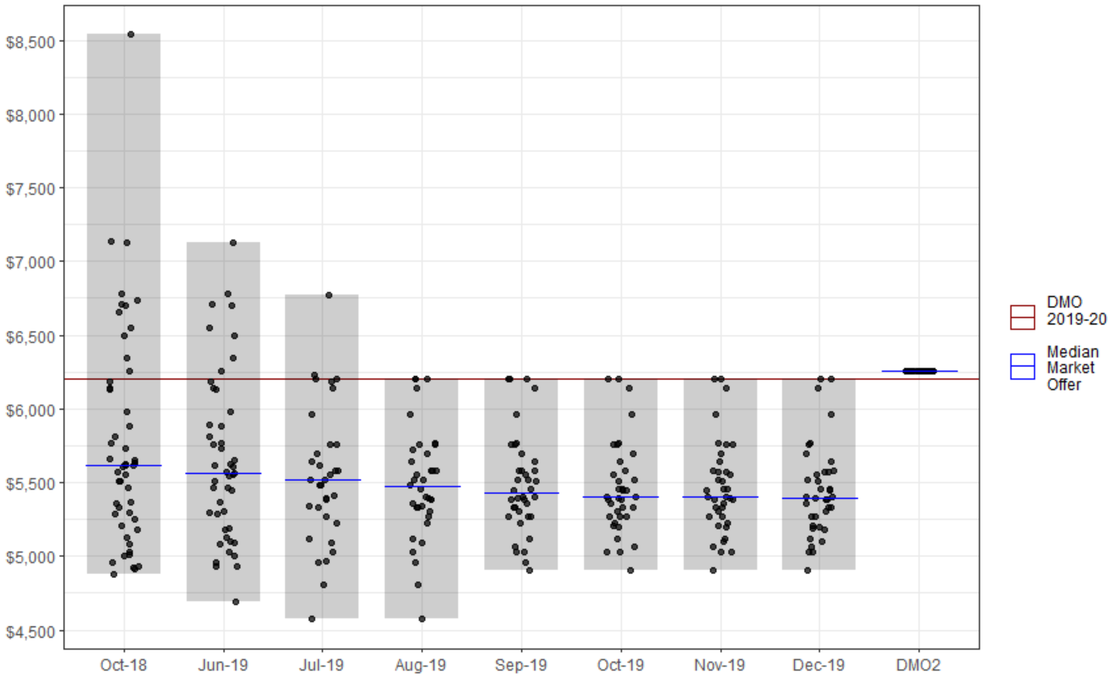


Figure B19: Market offer annual bill of all retailers for SME (including all discounts) in Energex's region

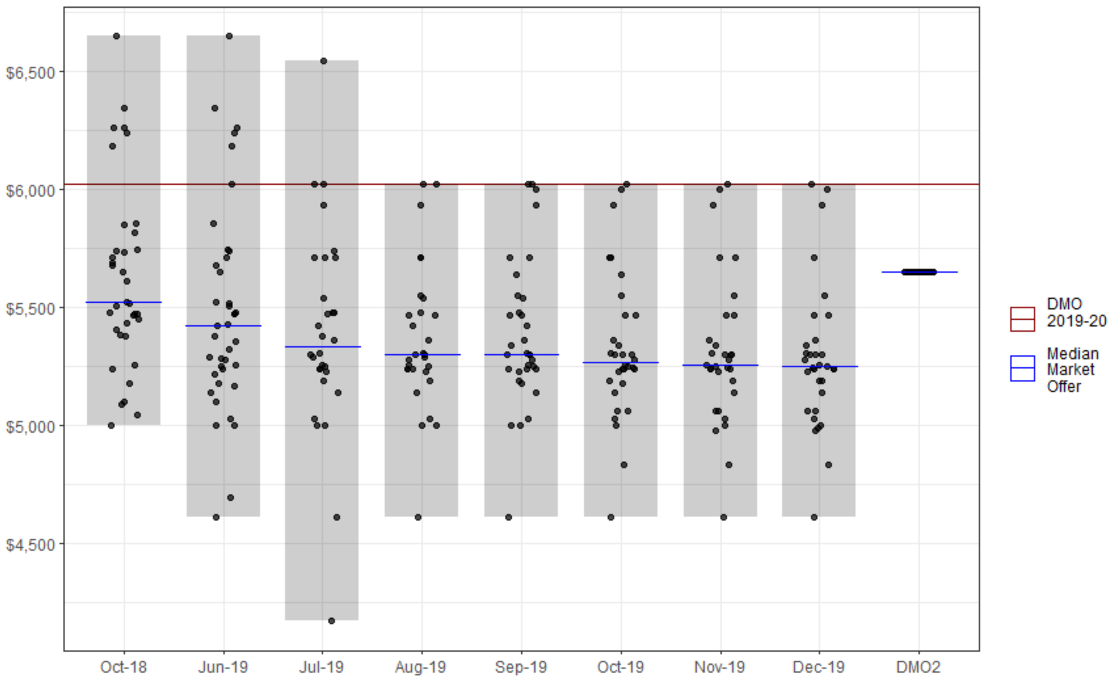


Figure B20: Market offer annual bill of all retailers for SME (including all discounts) in Essential Energy's region

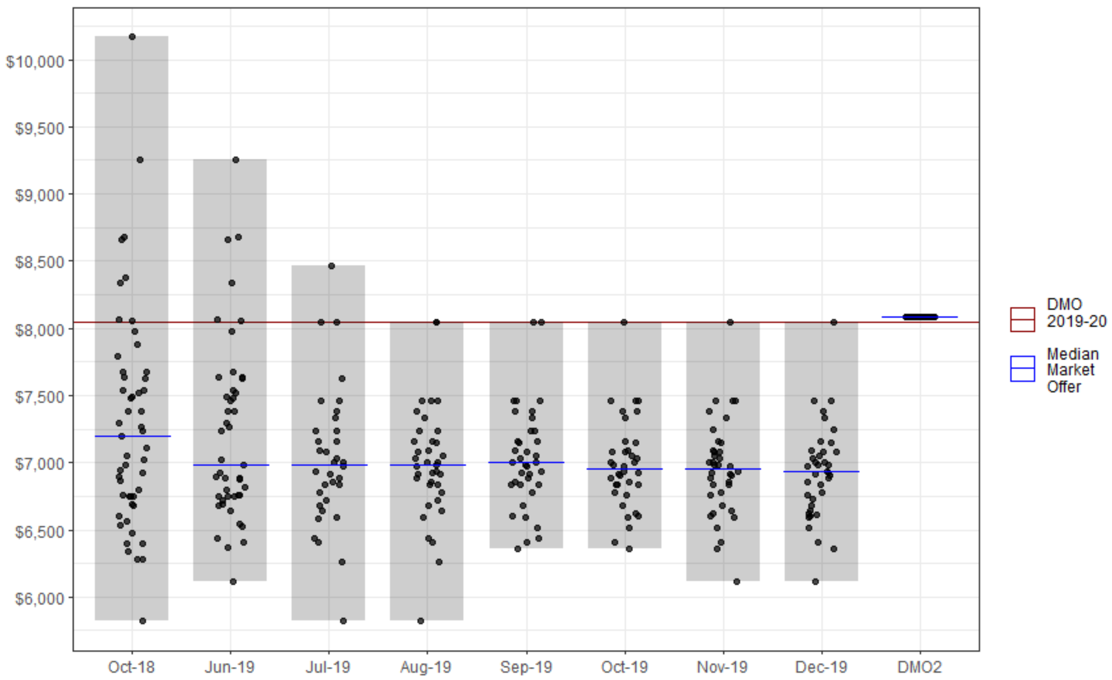
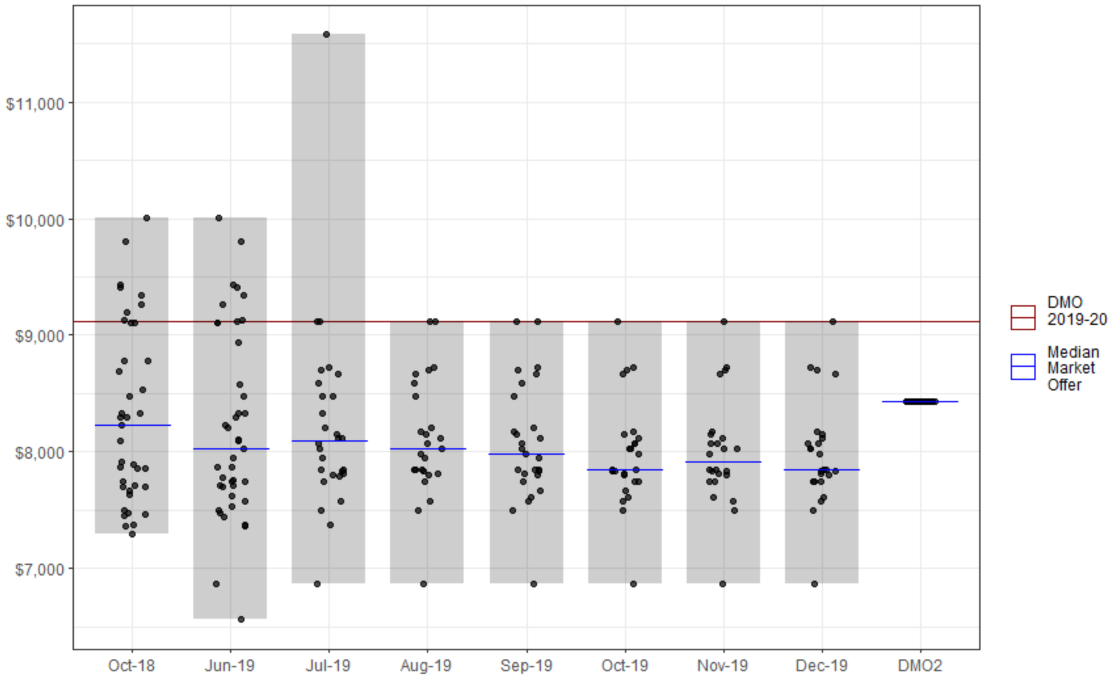


Figure B21: Market offer annual bill of all retailers for SME (including all discounts) in SAPN's region



C Forecast changes in cost components

As outlined in Section 3, we determined the DMO 2 prices using an indexation approach. DMO 1 prices are used as base prices for each distribution region. We have adjusted the DMO 1 prices for the forecast changes in underlying costs in 2020-21.

The approach to forecast the changes in network, wholesale and environmental costs is outlined below. To calculate the impact of these changes on underlying costs in retail annual bills, the cost stack for the base year (2019-20) was estimated. The overall year-on-year changes are then applied to the DMO 1 prices to arrive at DMO 2 prices. The detailed approach for the model is outlined below.

Key inputs: sources and calculations

C.1 Annual usage

As discussed in Section 4, the annual usage is unchanged from the DMO 1 Final Determination.

C.2 Network tariffs

For the base year, the network tariffs were sourced from the approved annual pricing proposals for 2019-20 for all the distribution regions. As outlined in the Position Paper, we only referenced relevant non-TOU network tariffs, given in the table below.

Table C1: Network tariffs to assess the changes in network charges

Distribution region	Residential flat rate	Residential CL	Small business flat rate
Ausgrid	Residential Non TOU - EA010	EA030 – Controlled load 1 EA040 – Controlled load 2	EA050 Small business non-TOU closed
Endeavour	Residential Energy (anytime) N70	Controlled Load 1 N50 Controlled Load 2 N54	General Supply TOU N84
Energex	Residential Flat NTC8400	Super Economy NTC9000 Economy NTC9100	Business Flat NTC8500
Essential	Residential Anytime BLNN2AU	Energy Saver 1 BLNC1AU Energy Saver 2 BLNC2AU	Small Business Anytime BLNN1AU
SAPN	Residential Single Rate (RSR) (flat rate fixed and variable tariffs)	Residential Single Rate (RSR) (CL variable tariff)	Business single rate (BSR)

As discussed in Section 3.4.3, for the determination year 2020-21, the network tariffs for this Draft Determination were sourced from the latest available indicative tariff structure statements (TSS). Those for Ausgrid, Endeavour and Essential are available in the approved annual pricing proposals for 2019-20.[108] For Energex and SAPN, they are available in the revised pricing proposal for the network revenue determination 2020-2025, post the publication of Draft Determinations.[109]

The network cost components include Distribution Use of System (DUOS), Transmission Use of System (TUOS), the relevant jurisdictional schemes, including Climate Change Fund (CCF) in NSW and Jurisdictional Scheme Obligations (JSO) in SA, and the relevant metering installation (capital) and maintenance (non-capital) charges in the Alternate Control Services (ACS). The network tariffs for these cost components have both a fixed (or supply) charge and a variable (or usage) charge. The calculation of annual network costs using these tariffs is below.

108 Pricing proposals and tariffs 2019-20, found here: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs

109 Determination and access arrangements, found here: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?f%5B0%5D=type%3Aaccc_aer_determination

Annual network cost component (for tariffs without CL) ($) = Fixed charge ($ pa) + Variable charge ($/MWh) x General Usage

Annual network cost component (for tariffs with CL) ($) = (Fixed charge for flat rate ($ pa) + Variable charge for flat rate ($/MWh) x General Usage) + (Fixed charge for CL1 ($ pa) + Variable charge for CL 1 ($/MWh) x CL Usage) x Proportion of CL1 + (Fixed charge for CL2 ($ pa) + Variable charge for CL 2 ($/MWh) x CL Usage) x Proportion of CL2

Total annual network cost ($) = Sum of all cost components ($) x (1 + GST)

Where the indicative network tariffs are not broken down into detailed components, the Network Use of System (NUOS) charges are considered directly. NUOS is an aggregated cost, including DUOS, TUOS and all jurisdictional schemes. However, where the break up is available, we have used the detailed network tariffs to better calculate network costs, which involves inclining or declining blocks. Considering our model annual usage, only the first block in the Endeavour and SAPN regions are relevant to assess network costs for our Draft Determination.

The expected changes in the network costs are calculated using the total annual network costs for all the tariffs. However, as outlined in Section 3.4.3, for the Final Determination it is unlikely the network tariffs will be available for the regions undergoing a revenue reset in 2020 – Energex and SAPN. Therefore, to calculate the expected changes in the network costs for these distribution areas we will have regard to the final network revenue determinations for the respective distribution businesses when they become available.

C.3 Wholesale and environmental costs

These cost estimates for the base year and forecasts for the determination year were provided by the Consultant.

As discussed in Chapter 3 and the Position Paper, the wholesale cost components include wholesale energy purchase costs (WEC), ancillary service charges, NEM fees, Reliability and Emergency Reserve Trading (RERT) costs, prudential costs. The environmental costs include the costs associated with LRET, SRES, and the relevant energy efficiency schemes — NSW Energy Savings Scheme (ESS) and the SA Retailer Energy Efficiency Scheme (REES).

The network loss factor is then calculated by applying the Distribution Loss Factor (DLF) and Marginal (or Transmission) Loss Factor (MLF) on these wholesale and environmental costs. The sources of these cost components, and the assumptions behind the estimates are discussed in the Consultant’s report.

Wholesale and environmental costs have only variable (or usage) charges. The calculation of annual network cost using these tariffs is outlined in the equations below.

Annual wholesale or environmental cost component (for tariffs without CL) ($) = Variable charge ($/MWh) x General Usage

Annual wholesale or environmental cost component (for tariffs with CL) ($) = (Variable charge for flat rate ($/MWh) x General Usage) + (Variable charge for CL 1 ($/MWh) x CL Usage) x Proportion of CL1 + (Variable charge for CL 2 ($/MWh) x CL Usage) x Proportion of CL2

Total annual wholesale or environmental cost ($) = Sum of all cost components ($) x (1 + loss factor) x (1 + GST)

The expected changes in the wholesale and environmental costs are calculated using the total annual network costs for all the tariffs.

For Endeavour and Essential, as confirmed by our Consultant, there is only one controlled load profile (CLP) available in the AEMO MSATS data. To have consistency in the cost assessment approaches across the DMO regions, we have applied the wholesale and environmental costs estimates from the Consultant for the single CLP to both controlled load tariffs in these two distribution regions.

C.4 Residual costs and step changes

The residual component is calculated as the difference between the DMO 1 prices and the aggregate total annual network, wholesale and environmental costs in the base year. The equations outlining the approach are given below.

Residual cost ($) = DMO 1 price ($) – sum of network, wholesale and environmental cost components ($)

As outlined in the Position Paper, the residual component was then adjusted for inflation using the consumer price index (CPI), sourced from the Reserve Bank of Australia (RBA) estimates.[110]

C.5 Indexing

The indexation of the DMO price is applied by applying a rate of change to each of the cost components. As mentioned above, to calculate the overall impact, the expected changes in the underlying costs are then weighted with the proportion of the base year costs of the DMO 1 prices. The equations outlining the approach are given below.

DMO 2 price = DMO 1 price x

(Proportion of network costs x change in network costs +

Proportion of wholesale costs x change in wholesale costs +

Proportion of environmental costs x change in environmental costs +

Proportion of residual costs x change in residual costs)

The indexation calculations are provided in the sections for each distribution region in the Consultant's report.

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110 We calculated the relevant CPI for the DMO 2 time period by averaging the RBA's forecast year to quarter for Dec 2020 and Jun 2021, from the RBA's November 2019 Appendix to the *Statement of Monetary Policy*.

The following charts show how the forecast changes in costs drive the DMO 1 prices to arrive at the DMO 2 prices for all five distribution regions and all three tariff types.

Figure C1: Forecast changes in costs, Ausgrid residential flate rate

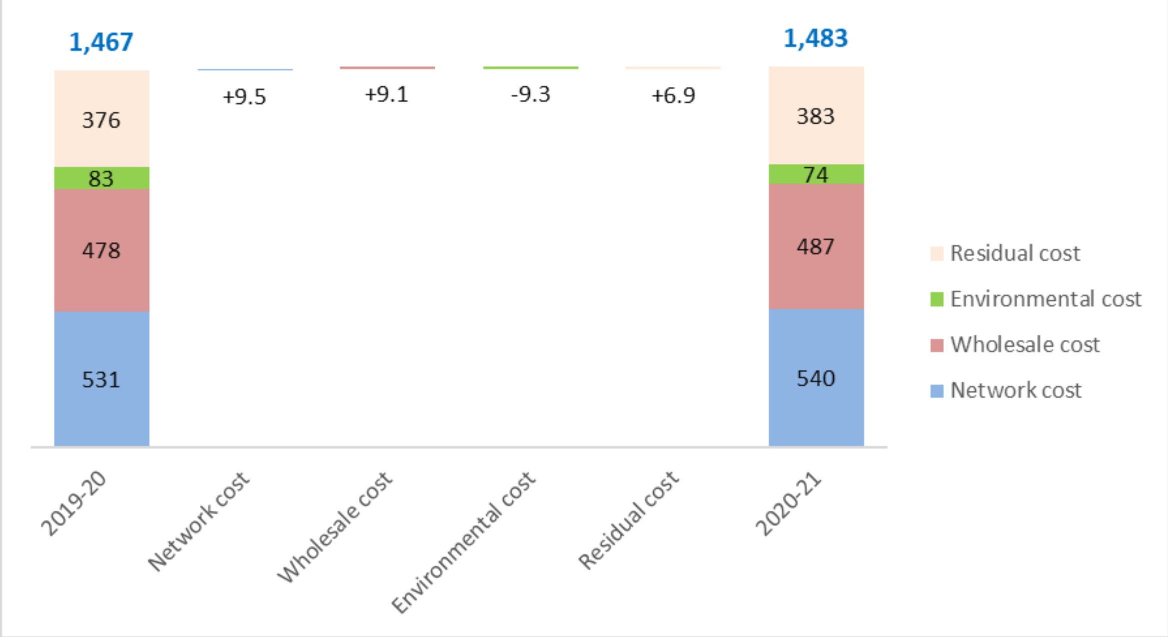


Figure C2: Forecast changes in costs, Endeavour Energy residential flate rate

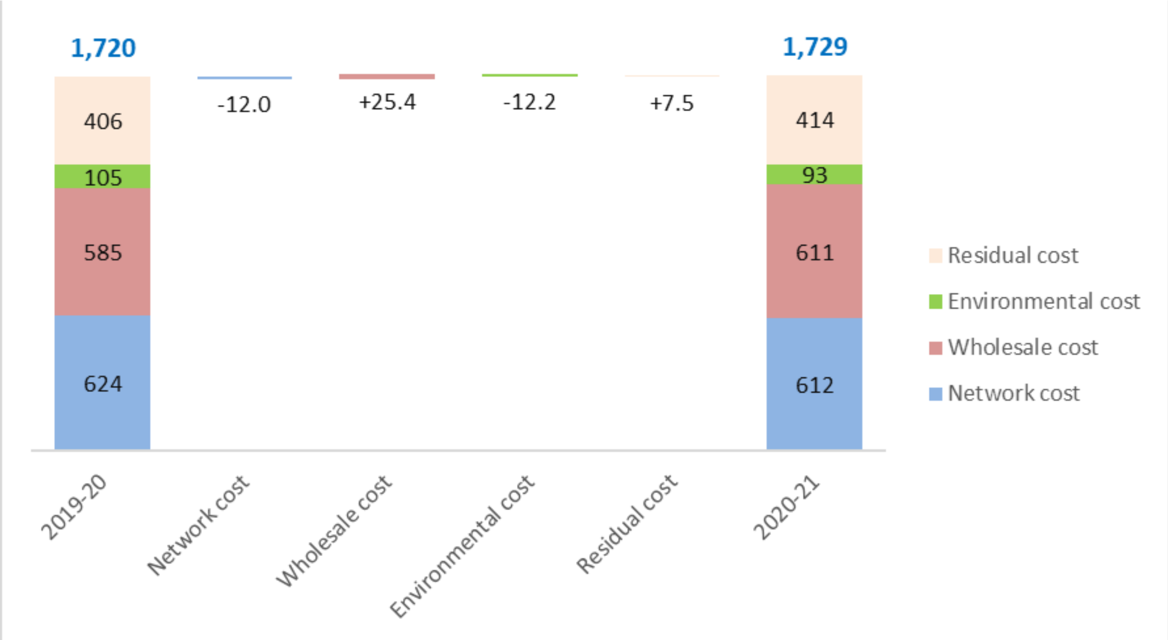


Figure C3: Forecast changes in costs, Essential Energy residential flate rate

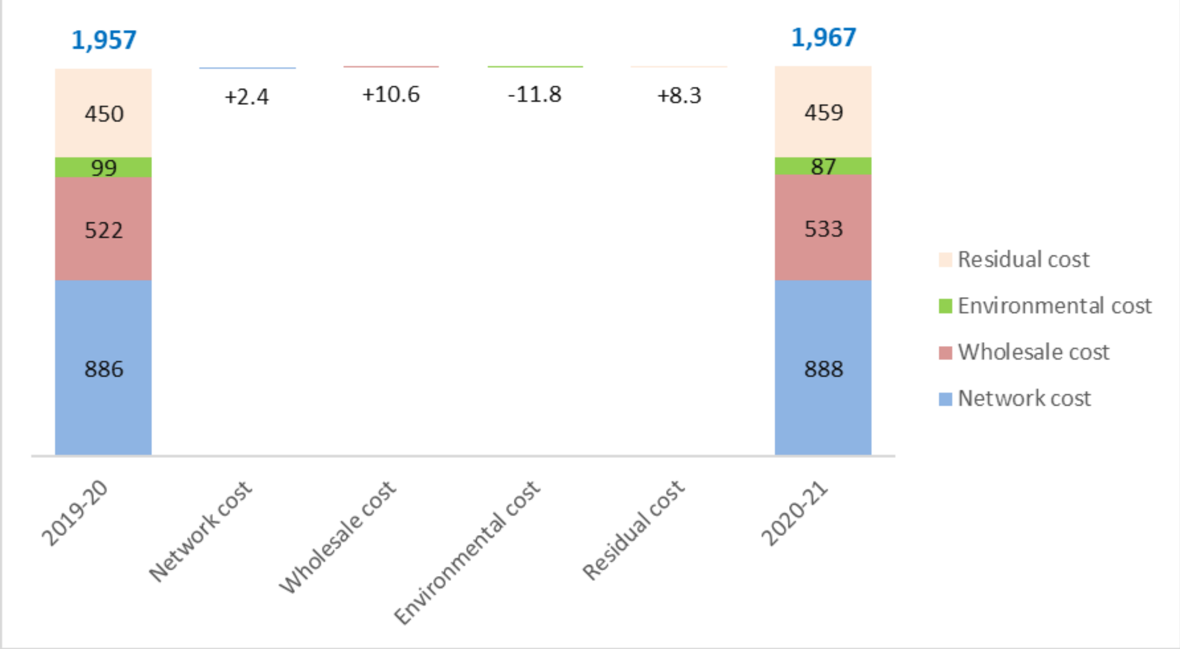


Figure C4: Forecast changes in costs, Energex residential flate rate

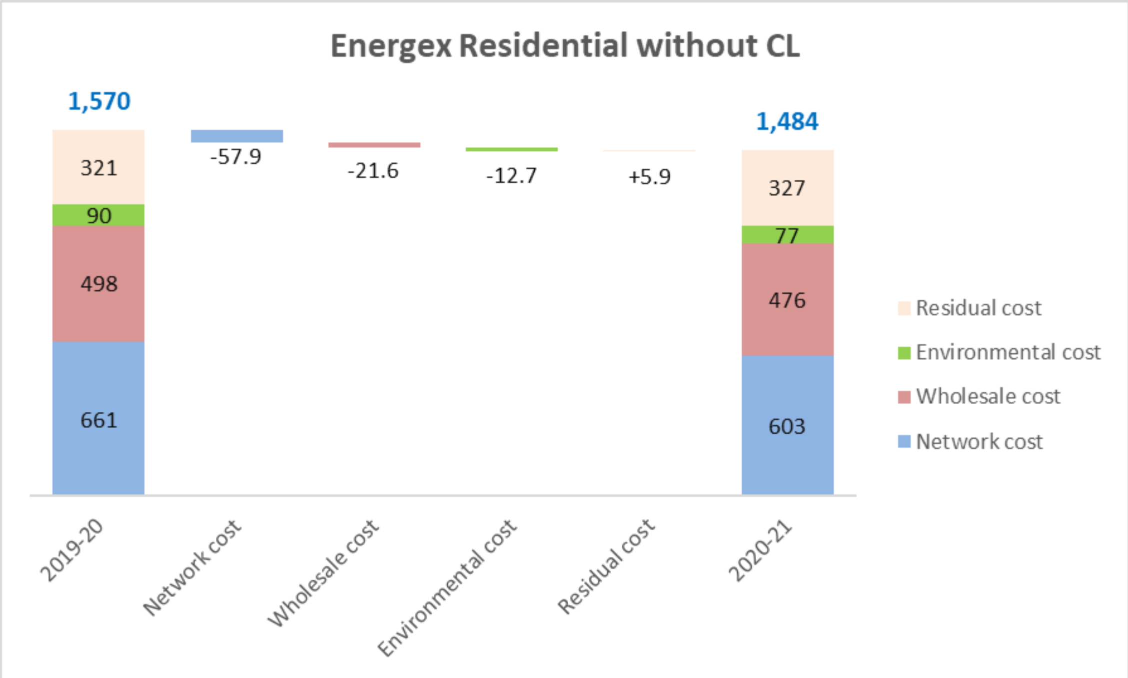


Figure C5: Forecast changes in costs, SAPN residential flate rate

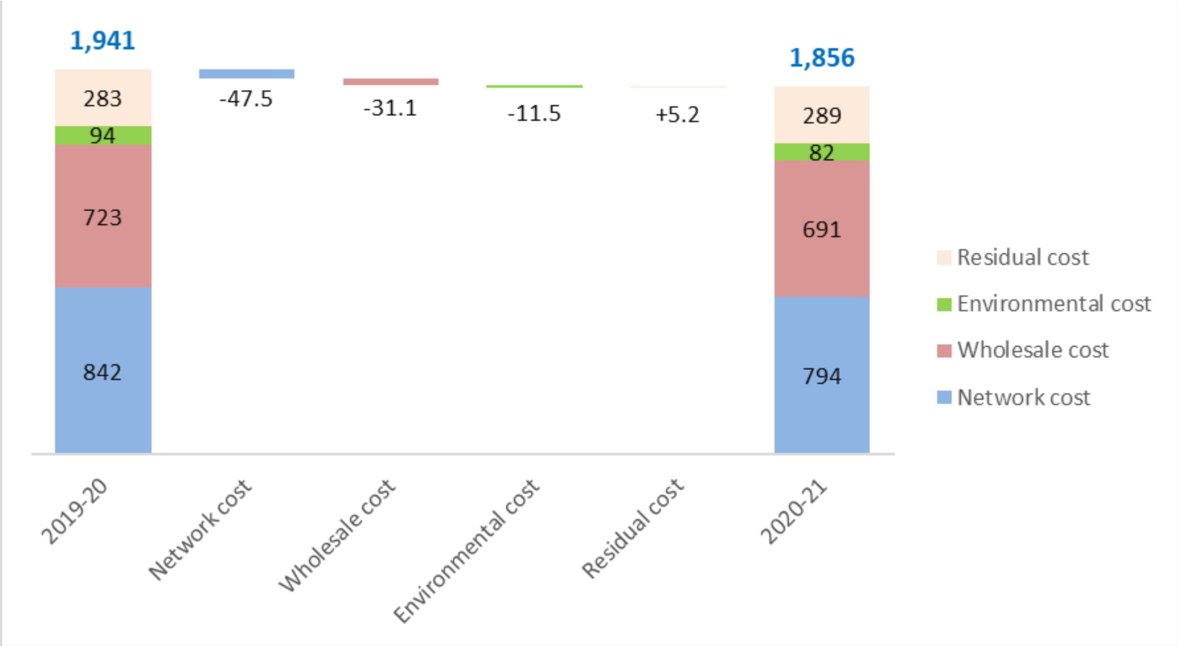


Figure C6: Forecast changes in costs, Ausgrid residential with CL

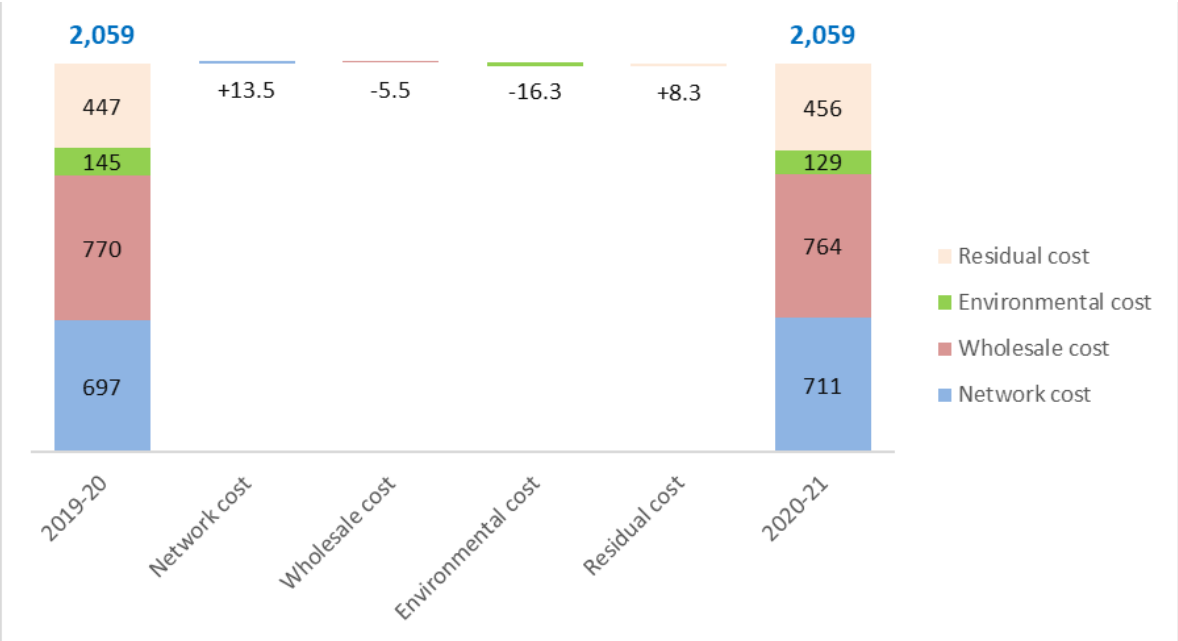


Figure C7: Forecast changes in costs, Endeavour Energy residential with CL

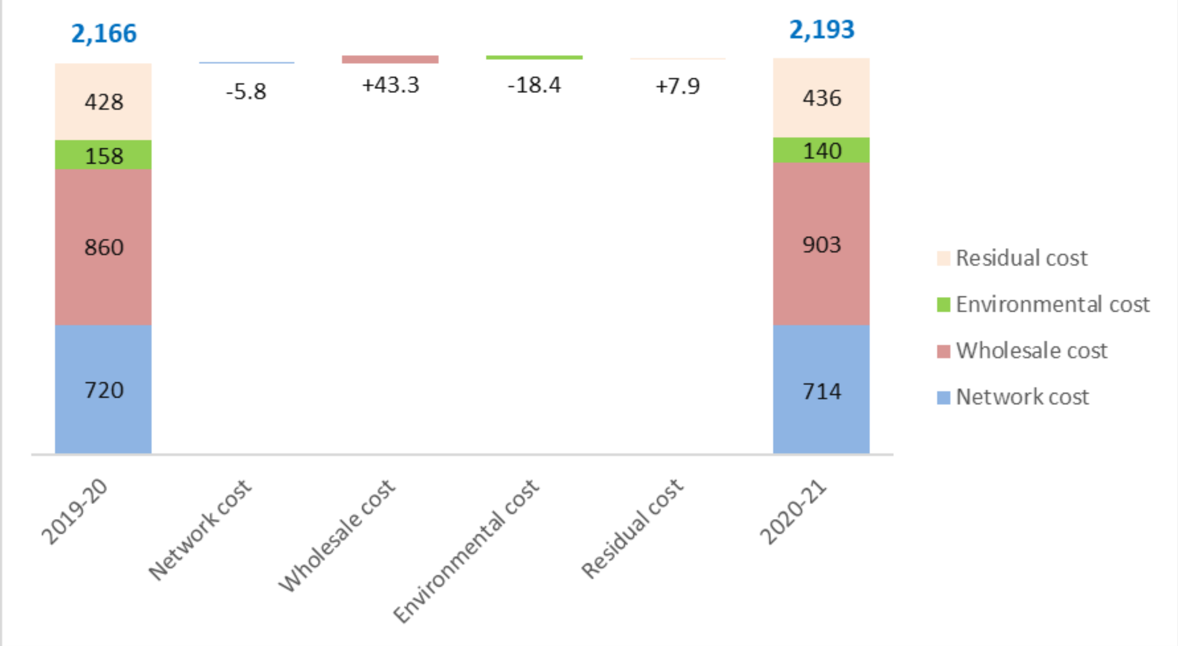


Figure C8: Forecast changes in costs, Essential Energy residential with CL

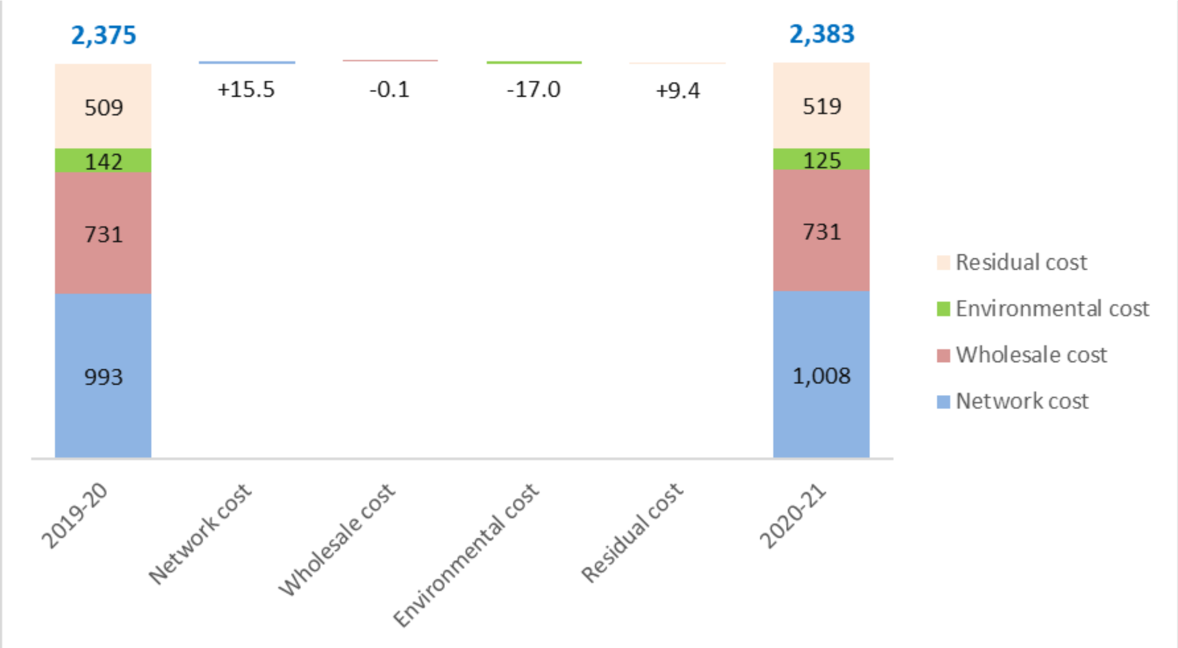


Figure C9: Forecast changes in costs, Energex residential with CL

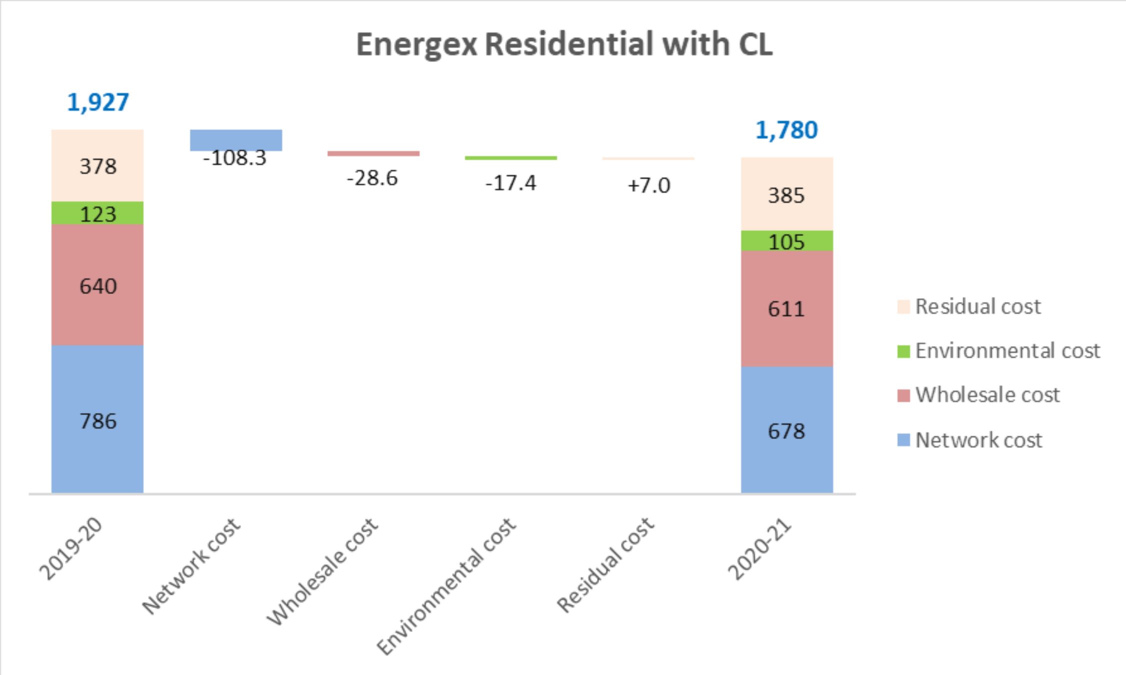


Figure C10: Forecast changes in costs, SAPN residential with CL

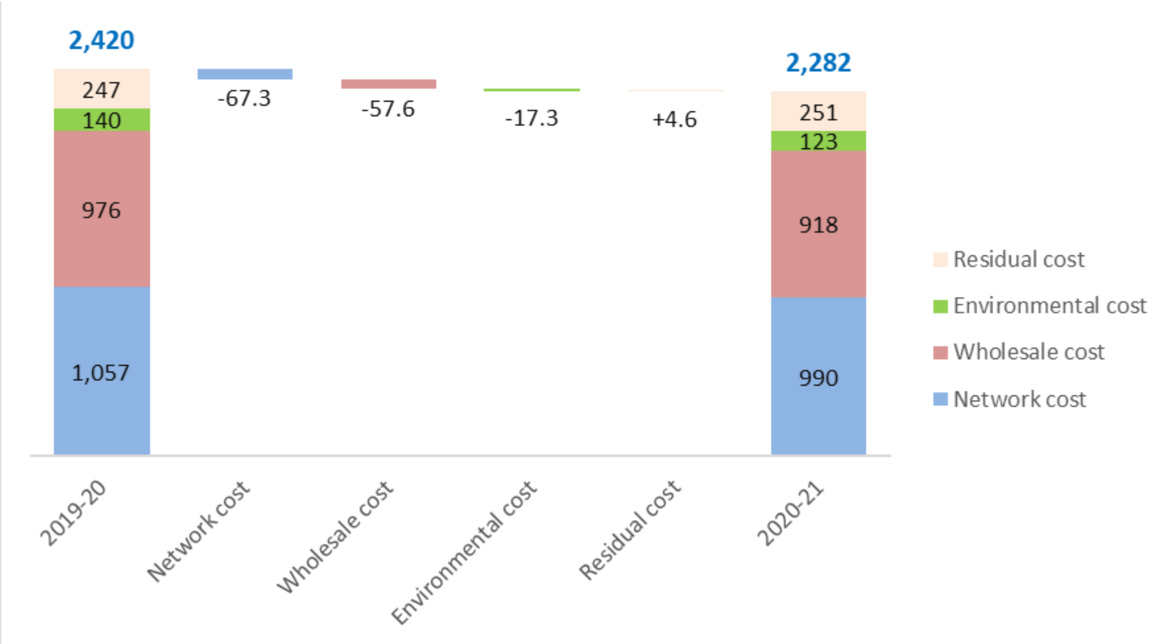


Figure C11: Forecast changes in costs, Ausgrid SME

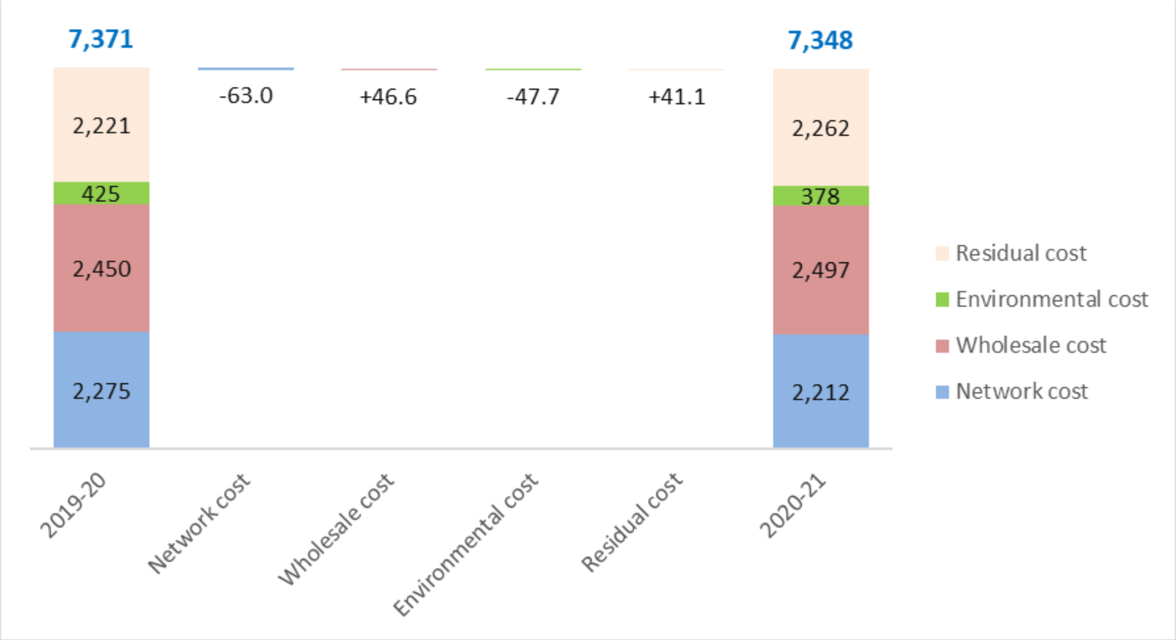


Figure C12: Forecast changes in costs, Endeavour Energy SME

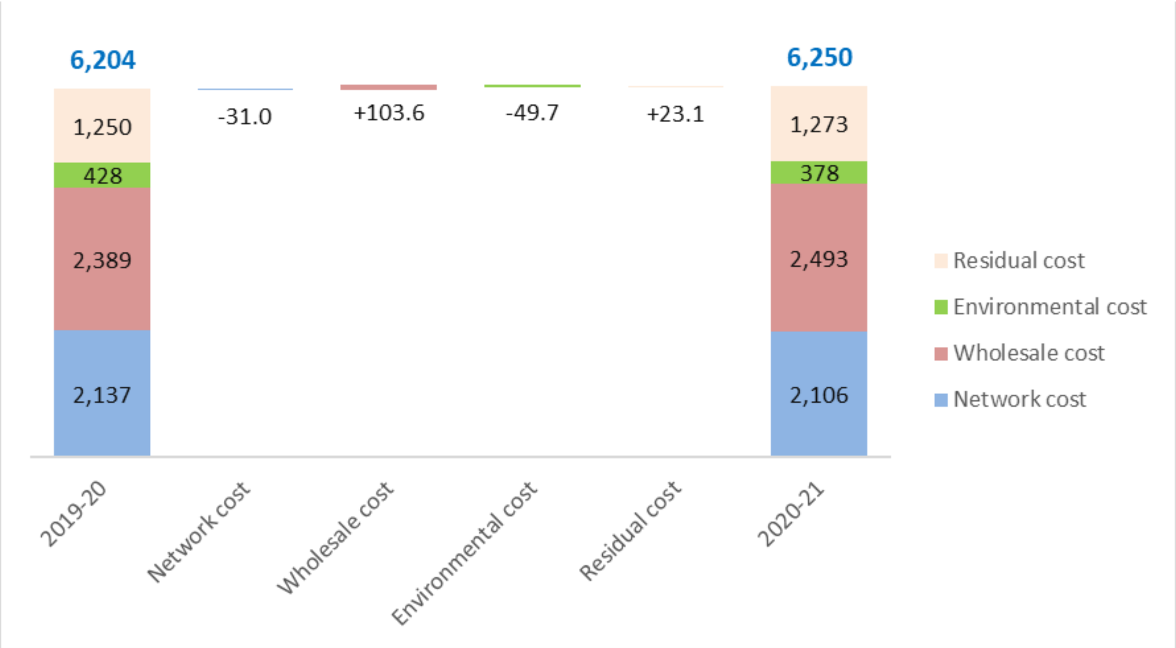


Figure C13: Forecast changes in costs, Essential Energy SME

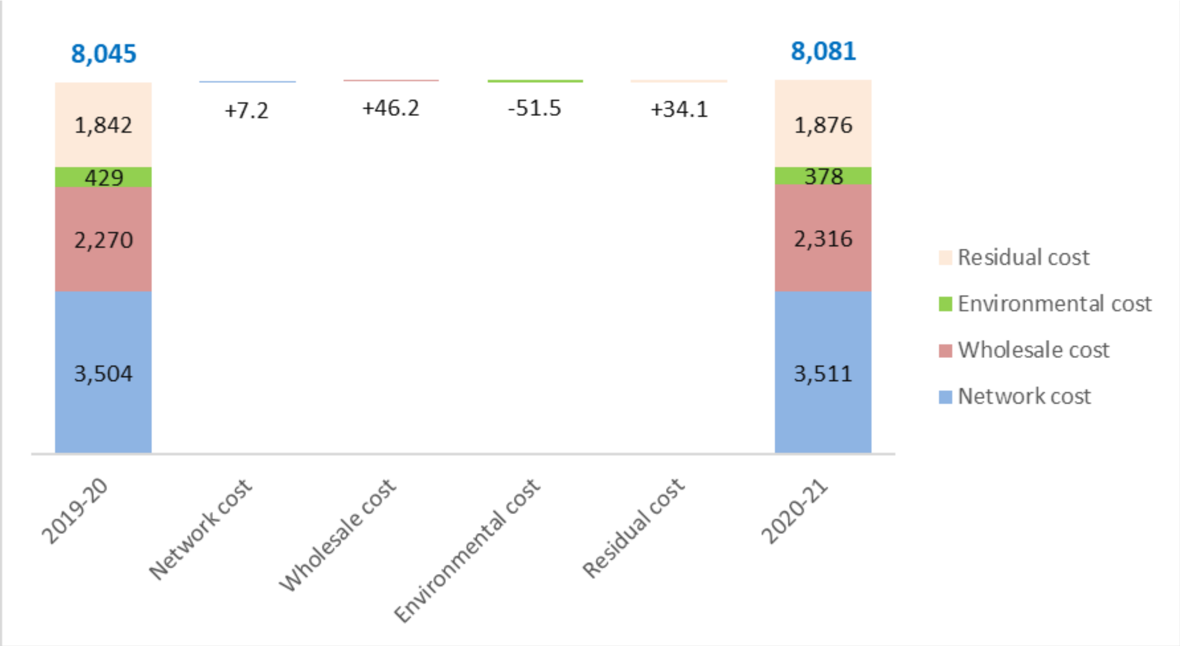


Figure C14: Forecast changes in costs, Energex SME

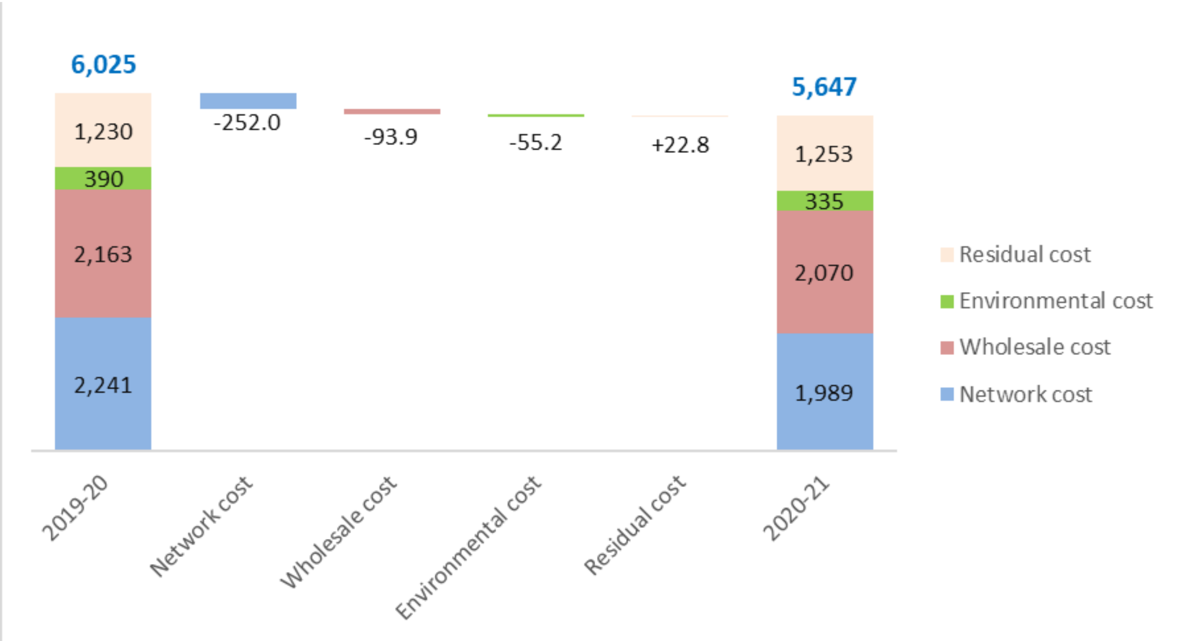
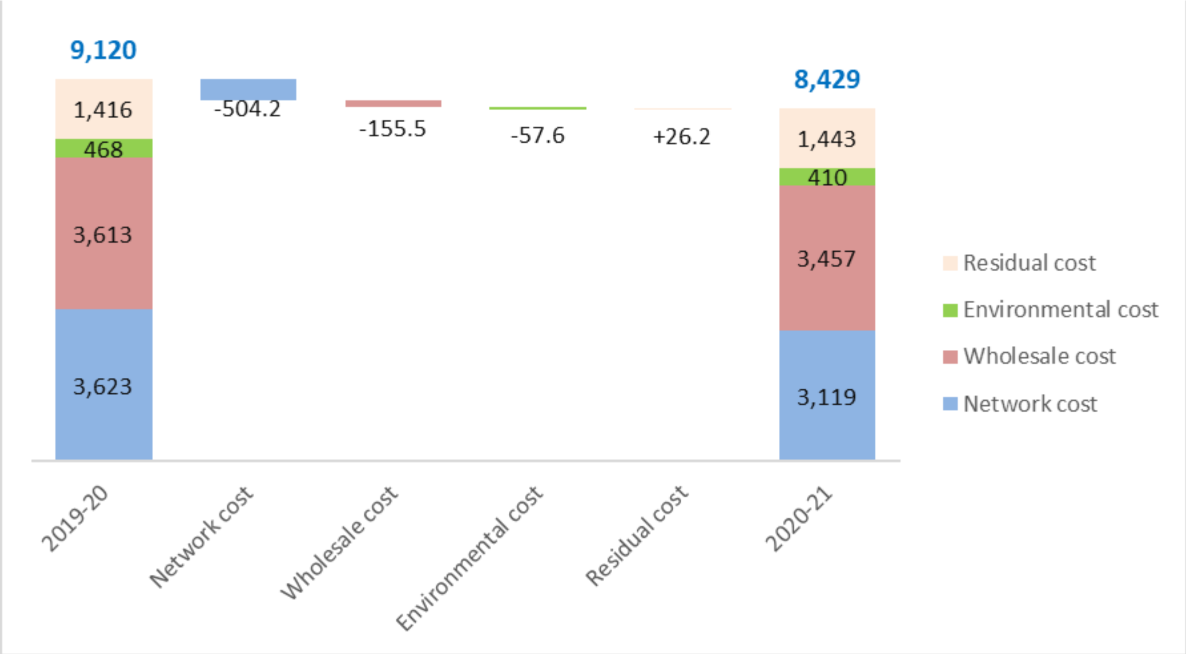


Figure C15: Forecast changes in costs, SAPN SME



D Time of use worked example on the application of a daily consumption profile

Our Draft Determination in relation to the timing and pattern of supply for TOU tariff types is to set a daily usage allocation for each network distribution region and customer type.

We have created these allocations by:

- deriving a daily amount of peak, off-peak and shoulder usage from our DMO 1 annual usage allocations (i.e. by dividing by 365)
- calculating hourly usage for each period, based on the TOU timing assumptions developed as part of our 2017 Energy Consumption Benchmarks project.

Table D1 shows how we derive hourly usage from the DMO 1 annual allocations for the Essential Energy distribution area.[111]

Table D2 shows the resulting daily profile.

Note, we have used designated peak, off-peak and shoulder periods identified in the Energy Consumption Benchmarks project to derive hourly usage amounts for our purposes. Our daily profiles developed for this Draft Determination do not specify peak, off-peak and shoulder usage periods. Instead, as discussed in Chapter 4, we propose allowing retailers the flexibility to divide the day into peak, off-peak and shoulder periods corresponding to their specific tariffs.

Table D1: Calculating hourly blocks from DMO 1 annual usage allocations, Essential Energy (4,600 kWh/year)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1,554.80	4.26	*2pm-8pm*	*6*	**0.710**
Off-peak	1,260.40	3.45	*10pm-7am*	*9*	**0.384**
Shoulder	1,784.80	4.89	*7am-2pm, 8-10pm*	*9*	**0.543**

111 Appendix E and F of the Draft Determination sets out our calculations and profiles for each region and customer type.

Table D2: Daily profile, Essential Energy region

Essential region – 4600 kWh/yr												
Time	*0000-0100*	*0100-0200*	*0200-0300*	*0300-0400*	*0400-0500*	*0500-0600*	*0600-0700*	*0700-0800*	*0800-0900*	*0900-1000*	*1000-1100*	*1100-1200*
kWh	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543
Time	*1200-1300*	*1300-1400*	*1400-1500*	*1500-1600*	*1600-1700*	*1700-1800*	*1800-1900*	*1900-2000*	*2000-2100*	*2100-2200*	*2200-2300*	*2300-2400*
kWh	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384

Two scenarios are included below to illustrate how a retailer would use the profile above to calculate annual peak, off-peak and shoulder usage for two separate retail tariffs.

D.1 Scenario 1 – Retail Tariff 'A' (aligned to network tariff TOU periods)

In scenario 1, the retail tariff has the same time periods as Essential Energy's approved TOU network tariff.

Table D3 shows the Essential Energy's network tariff periods.

Table D4 shows the Essential TOU periods overlaid on our daily profile.

Table D3: Retail Tariff A, periods

Essential Energy TOU network tariff periods	
Peak	7-9am, 5-8pm Weekdays
Off peak	10pm-7am weekdays All weekend
Shoulder	9-5, 8-10pm weekdays

Table D4: Essential Energy TOU tariff overlaid on DMO daily profile

Essential region – 4600kWh/yr												
Time	***0000-0100***	***0100-0200***	***0200-0300***	***0300-0400***	***0400-0500***	***0500-0600***	***0600-0700***	***0700-0800***	***0800-0900***	***0900-1000***	***1000-1100***	***1100-1200***
Wk day	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543
Wk end	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543
Time	***1200-1300***	***1300-1400***	***1400-1500***	***1500-1600***	***1600-1700***	***1700-1800***	***1800-1900***	***1900-2000***	***2000-2100***	***2100-2200***	***2200-2300***	*2300-2400*
Wk day	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384
Wk end	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384

Table D5 shows the daily total for each type of day. This is multiplied by the number of days to calculate the annual usage for each period.

Table D5: Retail Tariff A, period usage calculation

Day type	Peak	Off-peak	Shoulder
Weekday daily usage (kWh)	3.216	3.456	5.931
Weekday annual usage (kWh) – 261 days	*839.376*	*902.016*	*1547.991*
Weekend daily usage (kWh)	0	12.603	0
Weekend daily usage (kWh) – 104 days	*0*	*1310.712*	*0*
Total annual usage (kWh)	**839.38**	**2212.73**	**1547.99**

D.2 Scenario 2 – Retail Tariff 'B'

Tables D6, D7 and D8 illustrate how a retailer in the Essential region wanting to set a two-period TOU tariff with the same structure over each day of the year ('Tariff B'), would calculate usage in different periods.

Table D6: Essential Energy, retail Tariff B

Period	Time window
Peak	4-9pm all days
Off peak	9pm-4pm all days
Shoulder	NA

Table D7: Tariff B overlaid on DMO daily profile

Essential region – 4600kWh/yr												
Time	***0000-0100***	***0100-0200***	***0200-0300***	***0300-0400***	***0400-0500***	***0500-0600***	***0600-0700***	***0700-0800***	***0800-0900***	***0900-1000***	***1000-1100***	***1100-1200***
Every day	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543
Time	***1200-1300***	***1300-1400***	***1400-1500***	***1500-1600***	***1600-1700***	***1700-1800***	***1800-1900***	***1900-2000***	***2000-2100***	***2100-2200***	***2200-2300***	*2300-2400*
Every day	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384

Table D8: Tariff B, period usage calculation

Day type	Peak	Off-peak	Shoulder
Weekday daily usage (kWh) **365 days**	3.383	9.22	NA
Total annual usage (kWh)	**1234.80**	**3365.30**	**NA**

E Calculating hourly usage from DMO 1 annual profile

Table E1: Ausgrid general usage (no CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1244.1	3.409	*2pm-8pm*	6	**0.568**
Off-peak	1115.4	3.056	*10pm-7am*	9	**0.340**
Shoulder	1540.5	4.221	*7am-2pm, 8-10pm*	9	**0.469**

Table E2: Ausgrid general usage (CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1531.2	4.195	*2pm-8pm*	6	**0.699**
Off-peak	1372.8	3.761	*10pm-7am*	9	**0.418**
Shoulder	1896	5.195	*7am-2pm, 8-10pm*	9	**0.577**

Table E3: Endeavour general usage (no CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1646.4	4.511	*2pm-8pm*	6	**0.752**
Off-peak	1337.7	3.665	*10pm-7am*	9	**0.407**
Shoulder	1915.9	5.249	*7am-2pm, 8-10pm*	9	**0.583**

Table E4: Endeavour general usage (CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1747.2	4.787	*2pm-8pm*	6	**0.798**
Off-peak	1419.6	3.890	*10pm-7am*	9	**0.432**
Shoulder	2033.2	5.570	*7am-2pm, 8-10pm*	9	**0.619**

Table E5: Essential general usage (no CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1554.8	4.260	*2pm-8pm*	6	**0.710**
Off-peak	1260.4	3.453	*10pm-7am*	9	**0.384**
Shoulder	1784.8	4.890	*7am-2pm, 8-10pm*	9	**0.543**

Table E6: Essential general usage (CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1554.8	4.260	*2pm-8pm*	6	**0.710**
Off-peak	1260.4	3.453	*10pm-7am*	9	**0.384**
Shoulder	1784.8	4.890	*7am-2pm, 8-10pm*	9	**0.543**

Table E7: Energex general usage (no CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1568.6	4.298	*2pm-8pm*	6	**0.716**
Off-peak	1223.6	3.352	*10pm-7am*	9	**0.372**
Shoulder	1807.8	4.953	*7am-2pm, 8-10pm*	9	**0.550**

Table E8: Energex general usage (CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1500.4	4.111	*2pm-8pm*	6	**0.685**
Off-peak	1170.4	3.207	*10pm-7am*	9	**0.356**
Shoulder	1729.2	4.738	*7am-2pm, 8-10pm*	9	**0.526**

Table E9: SAPN general usage (no CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1252	3.430	*2pm-8pm*	6	**0.572**
Off-peak	1196	3.277	*10pm-7am*	9	**0.364**
Shoulder	1196	4.252	*7am-2pm, 8-10pm*	9	**0.472**

Table E10: SAPN general usage (CL)

TOU period	DMO 1 annual usage allocation – kWh/year	kWh/day	*AER benchmark time period assumptions*	*Hours/ day*	Hourly kWh usage
Peak	1314.6	3.602	*2pm-8pm*	6	**0.600**
Off-peak	1255.8	3.441	*10pm-7am*	9	**0.382**
Shoulder	1629.6	4.465	*7am-2pm, 8-10pm*	9	**0.496**

F TOU hourly consumption region profiles

Ausgrid distribution region

Table F1: Time of Use daily usage profile – Residential Usage without Controlled Load (3,900 kWh/yr)

Ausgrid general usage (no CL) (3900kWh/yr)												
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00
Usage (kWh/hour)	0.340	0.340	0.340	0.340	0.340	0.340	0.340	0.469	0.469	0.469	0.469	0.469

Ausgrid general usage (no CL) (3900kWh/yr)												
Time	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.469	0.469	0.568	0.568	0.568	0.568	0.568	0.568	0.469	0.469	0.340	0.340

Table F2: Time of Use daily usage profile – Residential General Usage with Controlled Load (4,800 kWh/yr)

Ausgrid general usage (CL) (4800kWh/yr)												
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00
Usage (kWh/hour)	0.418	0.418	0.418	0.418	0.418	0.418	0.418	0.577	0.577	0.577	0.577	0.577

Ausgrid general usage (CL) (4800kWh/yr)												
Time	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.577	0.577	0.699	0.699	0.699	0.699	0.699	0.699	0.577	0.577	0.418	0.418

Endeavour Energy distribution region

Table F3: Time of Use daily usage profile - Residential Usage without Controlled Load (4,900 kWh/yr)

Endeavour general usage (no CL) (4900kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.407	0.407	0.407	0.407	0.407	0.407	0.407	0.583	0.583	0.583	0.583	0.583	0.583	0.583	0.752	0.752	0.752	0.752	0.752	0.752	0.583	0.583	0.407	0.407

Table F4: Time of Use daily usage profile – Residential General Usage with Controlled Load (5,200 kWh/yr)

Endeavour general usage (CL) (5200kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.432	0.432	0.432	0.432	0.432	0.432	0.432	0.619	0.619	0.619	0.619	0.619	0.619	0.619	0.798	0.798	0.798	0.798	0.798	0.798	0.619	0.619	0.432	0.432

Essential Energy distribution region

Table F5: Flexible Tariff (Time of Use tariff) daily usage profile - Residential Usage without Controlled Load (4,600 kWh/yr)

Essential general usage (no CL) (4600kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384

Table F6: Time of Use daily usage profile – Residential General Usage with Controlled Load (4,600 kWh/yr)

Essential general usage (CL) (4600kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384

Energex distribution region

Table F7: Flexible Tariff (Time of Use tariff) daily usage profile - Residential Usage without Controlled Load (4,600 kWh/yr)

Energex general usage (no CL) (4600kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.372	0.372	0.372	0.372	0.372	0.372	0.372	0.550	0.550	0.550	0.550	0.550	0.550	0.550	0.716	0.716	0.716	0.716	0.716	0.716	0.550	0.550	0.372	0.372

Table F8: Time of Use daily usage profile – Residential General Usage with Controlled Load (4,400kWh/yr)

Energex general usage (CL) (4400kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.356	0.356	0.356	0.356	0.356	0.356	0.356	0.526	0.526	0.526	0.526	0.526	0.526	0.526	0.685	0.685	0.685	0.685	0.685	0.685	0.526	0.526	0.356	0.356

South Australian Power Networks distribution region

Table F9: Flexible Tariff (Time of Use tariff) daily usage profile - Residential Usage without Controlled Load (4,000 kWh/yr)

SAPN general usage (no CL) (4000kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.472	0.472	0.472	0.472	0.472	0.472	0.472	0.572	0.572	0.572	0.572	0.572	0.572	0.472	0.472	0.364	0.364

Table F10: Time of Use daily usage profile – Residential General Usage with Controlled Load (4,200 kWh/yr)

SAPN general usage (CL) (4200kWh/yr)																								
Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.382	0.382	0.382	0.382	0.382	0.382	0.382	0.496	0.496	0.496	0.496	0.496	0.496	0.496	0.600	0.600	0.600	0.600	0.600	0.600	0.496	0.496	0.382	0.382

G Controlled Load annual usage allocations

G.1 Ausgrid

Table G1: CL annual usage allocations (kWh/year) – Ausgrid

CL1 only	CL2 only	CL 1 and 2 (% of total)	
		CL1 (67%)	CL2 (33%)
2,000	2,000	1,340	660

G.2 Endeavour Energy

Table G2: CL annual usage allocations (kWh/yr) – Endeavour

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (67%)	CL 2 (33%)
2,200	2,200	1,474	726

G.3 Energex

Table G3: CL annual usage allocations (kWh/yr) – Energex

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (29%)	CL 2 (71%)
1,900	1,900	551	1,349

G.4 Essential Energy

Table G4: CL annual usage allocations (kWh/yr) – Essential Energy

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (77%)	CL 2 (23%)
2,000	2,000	1,540	460

G.5 SAPN

Table G5: CL annual usage allocations (kWh/yr) – SAPN

CL 1 only	CL 2 only	CL 1 and 2 (% of total)
1,800	NA	NA

H List of annual bill calculation assumptions

Subject	Specifications
Raw data	All available data from Energy Made Easy (EME) for October 2018 DMO 2019-20. Also, end of month EME data from June to December 2019.
Unique data set	For offers to be considered unique, the following criteria are applied: • Contract type (standing, market) • Retailer • Total annual bill (unconditional, conditional) • Fixed component (unconditional, conditional) • Usage component (unconditional, conditional) • CL fixed component (unconditional, conditional) • CL usage component (unconditional, conditional).
GST	Annual bill includes GST.
Demand component to flat tariff	Offers with a demand component to the flat tariff are removed from the data.
Usage allocation	Assumption of uniform consumption throughout the year to calculate the annual bill. Hence the daily consumption is consistent across the year with no adjustments for seasonality.
Days per year, days per quarter	365 days per year. Quarter calculated by daily charge times 365 days then divided by 4. No further adjustment made for leap years, as the contract start date varies depending on the customer.
Controlled loads CL1 & CL2	Where CL1 and CL2 are listed in the raw data, we apportion the total CL usage depending on the distribution region. This represents the customer being on a retail offer with a frat rate, CL1 and CL2. When the EME raw data only has CL1, this could represent CL1 or CL2 in a retailer's offer. Hence the customer is on a flat rate tariff with CL1, or a flat rate tariff with CL2.
Standing offer with controlled load	Some retailers offer three standing offers with CL – flat rate with CL1, flat rate with CL2 or flat rate with CL1 and CL2. We have used the highest standing offer for each

	retailer in calculating the median standing offer. This is usually CL2.
Discounts	Discounts on unconditional and conditional offers are applied to usage and supply as per each offer (percentage or dollar amount) as applied in EME.
Fees	Most fees are excluded for the calculation of the annual bill as they are one-off payments or dependent on the customer’s payment. These include connection fees, disconnection fees, late payment fees, direct debit dishonour payment fee, credit card processing fee, credit card merchant service fee, direct debit payments fee, establishment fee, and other fees.
Membership fees	This annual fee is effectively a supply charge, hence is included in the calculation of the annual bill.
Metering fees	Ongoing metering fees are included in the calculation of the annual bill. Up front metering charges are excluded, as there is no set scenario that would apply to most customers.
Bundling	No bundling included, such as gas, phone, internet, mobile, pool services.
Green charges	Assumption of no additional payment for green schemes to calculate the annual bill. Offers including green supply are removed from the data.
PV / Solar feed in tariffs	Assumption of zero PV solar exported. Offers with ‘solar’, ‘FiT’ and ‘FI’ are removed from data.
Recent offers removed	General offers available in EME with specific restrictions such as: • electric car • solar battery • football team membership • SME distinct industry (bakeries)

I Network TOU tariff structures

Table I1: Network TOU tariff structures

Network tariff name	Number of periods	Period	Times (24h)
DMO 1 annual allocation – nominal tariff structure	2P	**P**	0700-2100 all days
		OP	2100-0700 all days
	3P	**P**	1400-2000 all days
		OP	1000-0700 all days
		SH	0700-1400, 2000-2200 all days
	4P	**P**	1400-200 all days
		OP	2200-0700 all days
		SH1	0700-1400 all days
		SH2	2000-2200 all days
Ausgrid – Residential TOU (EA025)	3P	**P**	Summer (Nov-Mar) – 1400-2000 weekdays
			Winter (Jun-Aug) – 1700-2100 weekdays
		OP	2200-0700 weekdays
			all weekend
		SH	Summer– 0700-1400; 2000-2200 weekdays
			Winter – 0700-1700; 2100-2200 weekdays
			Non-summer/non-winter weekdays: 0700-2200
Endeavour Energy – Seasonal TOU (N71)	2P	**P**	High season peak (Nov-Mar) – 1600-2000 weekdays

			Low season peak (Apr-Oct) – 1600-2000 weekdays
		OP	Weekends
			2000-1600 weekdays
Endeavour – Residential TOU (N705)	3P	**P**	1300-2000 weekdays
		OP	2200-0700 weekdays All weekend
		SH	0700-1300, 2000-2200 weekdays
Essential Energy - Residential TOU (BLNT3AU)	3P	**P**	0700-0900, 1700-2000 weekdays
		OP	1000-0700 weekdays
			All weekend
		SH	0900-1700, 2000-2200 weekdays
Energex – Residential TOU		**P**	1600-2000 weekdays
		OP	1000-0700 weekdays and weekends
		SH	0700-1600, 2000-2200 weekdays
			0700-2200 weekends
SAPN*	**3P***	**P**	0600-1000, 1500-0100 all days
		OP	0100-0600 all days
*proposed 2020-21 tariff		***Solar Sponge***	1000-1500 all days

J Draft legislative instrument

Draft Legislative Instrument

Default Market Offer Prices 2020-21

1. Name

This instrument is the *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2020.*

2. Commencement

This instrument commences on 1 July 2020.

3. Authority

This instrument is made under section 16(1) of the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Regulations).

4. Definitions

In this Determination:

a) ***Regulations*** means the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019*; and

b) ***Residential Annual Usage without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

c) ***Residential Annual Price without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

d) ***Residential Annual Usage with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

e) ***Residential Annual Price with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

f) ***Small Business Annual Usage*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

g) ***Small Business Annual Price*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

h) ***General Usage*** means the non-controlled load usage of a small customer under s 6(2)(a) of the Regulations; and

i) ***Controlled Load Usage*** means the controlled load usage of a small customer under s 6(2)(a) of the Regulations.

j) Terms defined in the Regulations have the same meaning in this instrument.

5. Per-customer usage determination

In accordance with s 16(1)(a)(i) of the Regulations, the AER determines the per-customer amount of electricity supplied in specified distribution regions to small customers of the following types:

Per-customer annual usage determination

Distribution region	Residential Annual Usage without Controlled Load	Residential Annual Usage with Controlled Load		Small Business Annual Usage
		General Usage	*Controlled Load Usage*	
Ausgrid	3,900 kWh	4,800 kWh	2,000 kWh	20,000 kWh
Endeavour Energy	4,900 kWh	5,200 kWh	2,200 kWh	20,000 kWh
Energex	4,600 kWh	4,400 kWh	1,900 kWh	20,000 kWh
Essential Energy	4,600 kWh	4,600 kWh	2,000 kWh	20,000 kWh
SA Power Networks	4,000 kWh	4,200 kWh	1,800 kWh	20,000 kWh

6. Timing or pattern of supply determination

In accordance with s 16(1)(a)(ii) of the Regulations, the AER determines the timing or pattern of the supply of electricity in specified distribution regions to small customers:

a) Seasonality assumptions, all tariff and customer types

For all tariff and customer types, consumption has no seasonal weighting. That is, kilowatt hours consumed are assumed to be the same on each day of the year.

b) Daily usage profile for Flexible Tariffs (Time of Use tariffs) – Residential Usage without Controlled Load and General Usage / Residential Usage with Controlled Load

i. Ausgrid distribution region

Flexible Tariff (Time of Use tariff) daily usage profile – Daily Residential Usage without Controlled Load (3,900 kWh/yr)

Time	00:00 – 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 -13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	**0.340**	**0.340**	**0.340**	**0.340**	**0.340**	**0.340**	**0.340**	**0.469**	**0.469**	**0.469**	**0.469**	**0.469**	**0.469**	**0.469**	**0.568**	**0.568**	**0.568**	**0.568**	**0.568**	**0.568**	**0.469**	**0.469**	**0.340**	**0.340**

Flexible Tariff (Time of Use tariff) daily usage profile – Daily General usage – Daily Residential Usage with Controlled Load (4,800 kWh/yr)

Time	**00:00 - 01:00**	**01:00 - 02:00**	**02:00 - 03:00**	**03:00 - 04:00**	**04:00 - 05:00**	**05:00 - 06:00**	**06:00 - 07:00**	**07:00 - 08:00**	**08:00 - 09:00**	**09:00 - 10:00**	**10:00 - 11:00**	**11:00 - 12:00**	**12:00 - 13:00**	**13:00 - 14:00**	**14:00 - 15:00**	**15:00 - 16:00**	**16:00 - 17:00**	**17:00 - 18:00**	**18:00 - 19:00**	**19:00 - 20:00**	**20:00 - 21:00**	**21:00 - 22:00**	**22:00 - 23:00**	**23:00 - 00:00**
Usage (kWh/hour)	0.418	0.418	0.418	0.418	0.418	0.418	0.418	0.577	0.577	0.577	0.577	0.577	0.577	0.577	0.699	0.699	0.699	0.699	0.699	0.699	0.577	0.577	0.418	0.418

ii. Endeavour Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,900 kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.407	0.407	0.407	0.407	0.407	0.407	0.407	0.583	0.583	0.583	0.583	0.583	0.583	0.583	0.752	0.752	0.752	0.752	0.752	0.752	0.583	0.583	0.407	0.407

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (5,200 kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.432	0.432	0.432	0.432	0.432	0.432	0.432	0.619	0.619	0.619	0.619	0.619	0.619	0.619	0.798	0.798	0.798	0.798	0.798	0.798	0.619	0.619	0.432	0.432

iii. Energex distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.372	0.372	0.372	0.372	0.372	0.372	0.372	0.550	0.550	0.550	0.550	0.550	0.550	0.550	0.716	0.716	0.716	0.716	0.716	0.716	0.550	0.550	0.372	0.372

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,400kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.356	0.356	0.356	0.356	0.356	0.356	0.356	0.526	0.526	0.526	0.526	0.526	0.526	0.526	0.685	0.685	0.685	0.685	0.685	0.685	0.526	0.526	0.356	0.356

iv. Essential Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,600 kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.384	0.384	0.384	0.384	0.384	0.384	0.384	0.543	0.543	0.543	0.543	0.543	0.543	0.543	0.710	0.710	0.710	0.710	0.710	0.710	0.543	0.543	0.384	0.384

v. South Australian Power Networks distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,000 kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.472	0.472	0.472	0.472	0.472	0.472	0.472	0.572	0.572	0.572	0.572	0.572	0.572	0.472	0.472	0.364	0.364

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,200 kWh/yr)

Time	00:00 - 01:00	01:00 - 02:00	02:00 - 03:00	03:00 - 04:00	04:00 - 05:00	05:00 - 06:00	06:00 - 07:00	07:00 - 08:00	08:00 - 09:00	09:00 - 10:00	10:00 - 11:00	11:00 - 12:00	12:00 - 13:00	13:00 - 14:00	14:00 - 15:00	15:00 - 16:00	16:00 - 17:00	17:00 - 18:00	18:00 - 19:00	19:00 - 20:00	20:00 - 21:00	21:00 - 22:00	22:00 - 23:00	23:00 - 00:00
Usage (kWh/hour)	0.382	0.382	0.382	0.382	0.382	0.382	0.382	0.496	0.496	0.496	0.496	0.496	0.496	0.496	0.600	0.600	0.600	0.600	0.600	0.600	0.496	0.496	0.382	0.382

c) Controlled Load annual usage allocations

i. Ausgrid distribution region (kWh/year)

CL1 only	CL2 only	CL 1 and 2 (% of total)	
		CL1 (67%)	CL2 (33%)
2,000	2,000	1,340	660

ii. Endeavour Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (67%)	CL 2 (33%)
2,200	2,200	1,474	726

iii. Energex distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (29%)	CL 2 (71%)
1,900	1,900	551	1,349

iv. Essential Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (77%)	CL 2 (23%)
2,000	2,000	1,540	460

v. South Australian Power Networks distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2
1,800	NA	NA

7. Per-customer annual price determination

In accordance with s 16(1)(b) of the Regulations, the AER determines what it considers the reasonable per-customer annual price for supplying electricity in specified distribution regions to small customers of the types set out below.

Per-customer annual price determination (all prices GST-inclusive)			
Distribution region	**Annual Residential Price without Controlled Load**	**Annual Residential Price with Controlled Load**	**Small Business Annual Price**
Ausgrid	$1,483	$2,059	$7,348
Endeavour Energy	$1,729	$2,193	$6,250
Energex	$1,484	$1,780	$5,647
Essential Energy	$1,967	$2,383	$8,081
SA Power Networks	$1,856	$2,282	$8,429

If, in accordance with the Regulations, the cap is extended to an electricity retailer's standing offer prices for supplying electricity to a consumer who:

(a) is not a small customer; and
(b) would be a small customer apart from paragraph 6(3)(d) (customers with solar photovoltaic units),

then the annual prices set out above will also apply to these customer types.

DATED THIS [XX] DAY OF [MONTH] 2020

Australian Energy Regulator