FINAL DETERMINATION

Default Market Offer Prices 2020-21

30 April 2020

AUSTRALIAN ENERGY REGULATOR

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Contents

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
DMO 3	Default market offer determination for 2021-22
DUOS	Distribution use of system
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
LGC	Large-scale Generation Certificate

Shortened form	Extended form
LRET	Large-scale Renewable Energy Target
MMO	Median market offer
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
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RPP	Renewable power percentage
SAPN	SA Power Network
SBS	Solar Bonus Scheme (Queensland)
SME	Small and medium-sized business customers (enterprises)
SO	Standing offer
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
STP	Small-scale technology percentage
TOU	Time of use

Shortened form	Extended form
TUOS	Transmission use of system
UTP	(Queensland) Uniform tariff policy
VDO	Victorian Default Offer

1 Summary

This is our Final Determination for retail electricity default market offer (DMO) prices to apply from 1 July 2020 to 30 June 2021.

The DMO protects consumers by setting a maximum price a retailer can charge electricity customers on standing offers.

We made our initial DMO price determination in April 2019 following the introduction of the *Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019* (the Regulations). That determination set out the DMO prices that apply from 1 July 2019 to 30 June 2020. The introduction of DMO prices in 2019-20 led to significant decreases in the standing offer prices for residential and small business customers, with reductions from the median standing offer level ranging between:

- $118 (Energex region) and $181 (Essential Energy region) for residential customers on a flat rate tariff
- $169 (Energex region) and $236 (Endeavour Energy region) for residential customers on a flat rate tariff with controlled load
- $457 (Energex region) and $896 (SAPN region) for small business customers on a flat rate tariff.

We considered these outcomes were consistent with the policy objectives of reducing unjustifiably high standing offer prices for customers, while allowing retailers to recover the efficient costs of providing services and not dis-incentivising market participation by consumers and retailers.

Our Final Determination for DMO 2020-21 is to adjust the DMO 2019-20 prices to reflect forecast changes in wholesale, environmental and network costs. The residual costs (including retail costs) will be adjusted according to changes in the Australian Consumer Price Index (CPI).

The resulting DMO prices are set out in Table 1 below. Chapter 3 sets out our annual price determination for DMO prices.

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

Distribution region		Residential without CL	Residential with CL	Small Business without CL
Ausgrid	DMO 2 Price	$1,462	$2,024	$7,240
	for annual usage of	3,900 kWh	General usage 4,800 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 1	-$5 (-0.3%)	-$35 (-1.7%)	-$131 (-1.8%)
Endeavour	DMO 2 Price	$1,711	$2,165	$6,177
	for annual usage of	4,900 kWh	General usage 5,200 kWh + CL 2,200 kWh	20,000 kWh
	Difference to DMO 1	-$9 (-0.5%)	-$1 (0.0%)	-$27 (-0.4%)
Essential	DMO 2 Price	$1,960	$2,356	$8,041
	for annual usage of	4,600 kWh	General usage 4,600 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 1	+$3 (+0.2%)	-$19 (-0.8%)	-$4 (0.0%)
Energex	DMO 2 Price	$1,508	$1,812	$5,760
	for annual usage of	4,600 kWh	General usage 4,400 kWh + CL 1,900 kWh	20,000 kWh
	Difference to DMO 1	-$62 (-3.9%)	-$115 (-6.0%)	-$265 (-4.4%)
SAPN	DMO 2 Price	$1,832	$2,244	$8,305
	for annual usage of	4,000 kWh	General usage 4,200 kWh + CL 1,800 kWh	20,000 kWh
	Difference to DMO 1	-$109 (-5.6%)	-$176 (-7.3%)	-$815 (-8.9%)

From 1 July 2020, DMO prices for residential customers will be:

- $9 lower to $3 higher in New South Wales (NSW) (depending on the distribution region)
- $62 lower in South East Queensland

- $109 lower in South Australia.

DMO prices for residential customers with controlled load will be:

- $1 to $35 lower in NSW (depending on the distribution region)
- $115 lower in South East Queensland
- $176 lower in South Australia.

DMO prices for small business customers will be:

- $4 to $131 lower in NSW (depending on the distribution region)
- $265 lower in South East Queensland
- $815 lower in South Australia.

DMO prices are 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. The DMO price 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 price. This aims to help customers more simply compare the prices of different offers.

DMO prices for 2020-21 have been derived based on our forecasts of the key cost components that make up the retail electricity bill.

We are forecasting reductions in wholesale energy costs for hedging and purchasing on the spot market across most of the DMO distribution regions for 2020-21. This is a result of lower contract prices driven by factors such as the strong increase in renewable investment coming on-line and the reduction of gas prices for gas fired generation.

Smaller decreases and some increases are forecast for wholesale energy costs in the NSW regions, compared with South Australia and South East Queensland. This result is driven by two factors; the smaller reductions in contract prices in NSW, and the higher hedging costs associated with the peakier load forecast in NSW regions. This peakiness is due to the forecast increase in the uptake of rooftop solar in NSW, where current penetration is relatively lower. The forecast increase in wholesale energy costs for the Endeavour region is due to the time of day load profile shape exhibiting a higher degree of volatility compared with other regions in NSW.

Other energy costs associated with participating in the NEM wholesale market are forecast to increase across most distribution regions in 2020-21. The most significant change in other energy costs are the costs associated with ancillary services recovery, which on average have tripled in all regions and customer types.

Networks cost forecasts vary across the distribution regions and different customer types. The Energex and SAPN regions are currently undergoing network revenue determinations for the 2020-25 regulatory control period. The changes in network cost forecasts observed in these regions result from transitioning between one regulatory period and the next. In Energex, reductions in network costs are largely offset by the addition of jurisdictional scheme costs for 2020-21.[1]

The NSW distribution regions are within a regulatory control period and the distribution and transmission 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. The network costs for all customer types in NSW regions are forecast to change between a 3 per cent decrease to a 2 per cent increase in 2020-21.

We expect environmental costs to fall significantly across all regions and customer types for 2020-21. 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 cost of Small Scale Energy Scheme (SRES) is projected to increase by 1 per cent, with the expectation that small-scale installations (rooftop solar and solar water heater) will increase slightly in 2021.

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

Our consideration of these cost forecasts is discussed in detail in Chapter 3.

We outline our model annual usage determinations in Chapter 4. Our Final 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.

Following amendments to the Regulations in February 2020, the DMO price also applies to residential customers on solar and TOU tariffs, and to small business customers on solar tariffs.

In response to stakeholder feedback, our Final Determination specifies a usage profile showing electricity usage during each hour of the day, over a 24 hour period for each distribution region. Retailers determine when their peak, off-peak and shoulder usage periods apply and their prices for these tariff windows. Using our daily usage profile they can calculate the annual TOU price. If need be, they can adjust the tariff windows and prices to ensure the annual price remains below the DMO cap. We believe this approach will minimise any potential impacts on network tariff reform and retailer innovation. Chapter 4 sets out our approach to setting the DMO price for TOU customers.

1 On 15 March 2020, the Queensland Government announced it would pay a $50 Asset Ownership Dividend (AOD) for all residential customers in 2020 (continuing AOD payments made in 2018 and 2019).

The current evidence suggests the introduction of the DMO has reduced high priced standing offers while maintaining the availability of lower priced market offers. This outcome is consistent with the DMO objectives of providing consumer protection to standing offers customers as well as maintaining incentives for market participation and competition. Refer to **Appendix B** for further information. We will continue to monitor the market as part of preparing for the next DMO determination process.

We have consulted on how we should take into account the impacts of the recent COVID-19 pandemic in making the DMO determination for 2020-21. Based on the available information, we have decided not to make any form of adjustment to this Final Determination in response to COVID-19. This is primarily due to the current uncertainty about the impacts of COVID-19 and the paucity of information to make an adjustment at this time. Given the circumstances, we believe there is merit in considering introduction of a re-opener provision in the Regulations governing the DMO. This would require an amendment to the Regulations, which is ultimately a decision for the Commonwealth Government. This is discussed in section 2.5.

Structure of this Final Determination

Chapter 2 outlines the background and the legislative framework for setting DMO prices.

Chapter 3 sets out our Final Determination for DMO prices for 2020-21.

Chapter 4 sets out our model annual usage determination, covering the annual usage amount and the timing and pattern of supply.

Appendix A – List of submitters to AER Draft Determination and COVID-19 consultation

Appendix B – Market offer analysis for each distribution region

Appendix C – List of annual bill calculation assumptions

Appendix D – Forecast changes in cost components

Appendix E – Matters we have had regard to in determining DMO prices

Appendix F – Legislative instrument

Appendix G – Statement of compatibility with human rights

Appendix H – Nominal price movements from Draft Determination to Final Determination

2 Background

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 Final 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 otherwise no retail price regulation.

2.1 What is the default market offer (DMO)?

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 customers under a standard retail contract if the small customer does not accept a market offer.[2]

Retailers must publish, on their websites, a standard retail contract for all distribution regions in NEM regions where they operate.[3] Retailers' standard retail contracts must adopt the model terms and conditions set out in the NERR.[4]

As summarised in the Australian Competition and Consumer Commission (ACCC) Retail Electricity Pricing Inquiry (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

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2 NERL, s. 22(1); NERR, r. 16.

3 NERL, s. 25(1).

4 NERL, s. 25.

- a set period for reminder notices
- no more than one price change every six months.[5]

In the REPI final report , the 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 for advertising market offers. 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 *Competition and Consumer (Industry Code – Electricity Retail) Regulations* 2019 (the Regulations) giving effect to the DMO.

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.

2.2 Legislative requirements

The legislative framework for determining DMO prices is contained in the *Competition and Consumer (Industry Code – Electricity Retail) Regulations* 2019 (the Regulations).[6] The AER's role under the Regulations is to determine DMO prices each year for each network distribution region and customer type.

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 with the reference price.

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[7]

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

6 *Competition and Consumer (Industry Code – Electricity Retail) Regulations* 2019 (the Regulations), 4 April 2019; and *Competition and Consumer Legislation Amendment (Electricity Retail) Regulations 2020,* 6 February 2020: https://www.legislation.gov.au/Details/F2019L00530

7 Regulations s. 10.

- small customers must be told how a retailer's prices compare with the AER-determined annual price[8]

- 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.[9]

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[10] (the model annual usage)[11]

- 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).[12]

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

As DMO prices and the reference price 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.

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 particular tariff type.

Customers in jurisdictions with previously deregulated prices

DMO prices apply in distribution regions not otherwise subject to retail price regulation.[13] These regions are:

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8 Regulations s. 12.

9 Regulations, s. 14.

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

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

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

13 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.

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

Customers on standing offers

The majority of standing offer customers are customers of the 'Tier One' retailers – AGL, EnergyAustralia and Origin Energy.[14] The Tier One retailers are otherwise referred to as Local Area Retailers (LARs), who acquired the customers of a particular region at the time of retail market privatisation.[15]

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)[16]
- have moved into a premises and receive supply from the existing retailer supplying the premises but are yet to make contact with the retailer [17]
- have defaulted to a standing offer following the expiry of a market contract.[18]

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

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

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14 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.

15 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.

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

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

18 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 regions

	Residential standing offer customers (Number and %)	Small business standing offer customers (Number and %)
NSW	379,411 (11.6%)	69,700 (21.2%)
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	171,285 (12.1%)	25,345 (23.3%)
SA	61,075 (7.8%)	12,823 (14.6%)
Total standing offer customers	**611,771**	**107,868**

Source: AER Retail Market Performance update, Quarter 2, 2019-20.

Small customers of certain types

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. This includes customers on TOU and solar tariffs.
- *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 100 MWh per year. This includes customers on solar tariffs.

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

- their tariff includes demand charges[19]
- they are supplied within an embedded network[20]

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19 Regulations, s. 6(3)(a).

20 Regulations, s. 6(3)(c).

- they receive electricity via a pre-payment meter.[21]

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

2.4 Our consultation process

In making this Final Determination, we have undertaken a consultation process consistent with section 17(1) of the Regulations.

- On 19 September 2019 we published a Position Paper and received 13 submissions.
- We held a stakeholder forum in Sydney on 26 November 2019 which was attended by around 35 stakeholders.
- We published a Draft Determination for public consultation on 10 February 2020 and received 13 submissions.
- We held a webinar attended by about 60 stakeholders on 3 March 2020.
- We published our Consultant, ACIL Allen's report and modelling data, as well as our price index and cost assessment model.
- On 1 April 2020 we published an open letter to stakeholders seeking views on how we should take account of COVID-19 impacts in making our Final Determination. We received 22 submissions.

[21] Regulations, s. 6(3)(b).

In addition, we have held numerous bilateral meetings with a range of stakeholders throughout the process.

We have had regard to the submissions and information we have received through our consultations and the advice from our Consultants in making this determination.

2.5 How have we taken COVID-19 into account in making this determination?

On 1 April 2020, we published a letter seeking stakeholder views on how the AER should take into account the impacts of COVID-19 in making the DMO determination for 2020-21.

In response to our letter, we received 22 submissions from retailer, consumer advocacy, and industry association stakeholders – refer to **Appendix A** for a list of submissions.

The key themes in stakeholder submissions included:

- A recognition of the current uncertainty and difficulty in forecasting the cost impacts of COVID-19.
- Stakeholders acknowledged the considerable uncertainty in forecasting the wholesale, environmental and network costs components at this time. There was no clear consensus on whether these types of costs would materially increase or decrease as a result of COVID-19.
    - Some submissions noted that the reduction in demand would lead to a further softening of wholesale energy costs, and recommended a reduction to the DMO price.[22]
    - A number submissions did not recommend amending our current forecasting approach for these cost components.[23]
- The majority of retailer submissions identified two categories of retail costs that would likely increase as a result of COVID-19:[24]

[22] For example, Energy Consumers Australia, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 14 April 2020, p. 1.

[23] Amaysim, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 3 - 4. 1st Energy, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1. Nectr, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 - 2.

[24] Amaysim, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 4. Powershop/Meridian, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 2. 1st Energy, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1. Quinbrook Infrastructure Partners/Cape Byron Power/Energy Locals/Energy Trade, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 - 3. ERM Power, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 2. iON Holdings, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 2. Simply Energy, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April

- Increases in bad and doubtful debts as a result of more customers experiencing financial vulnerability. This includes debt write-offs and provisions for doubtful debt. Retailers also identified additional short term debt carrying costs due to more customers accessing hardship programs and extended payment plans. A number of retailer submissions noted support for the AER's Statement of Expectations, however identified this would require operational changes and increased costs, including for debt processes.
- Increases in cost to serve as a result of:
    - Requirements for staff to work from home.
    - The closure of international call centres, which has required some retailers to bolster onshore capabilities.
    - Increases in the volume and complexity of communication with customers. This is due to an increase in calls about payment difficulty, hardship and/or broken payment plans.

- A number of submissions stated that DMO prices should be adjusted for these COVID-19-related retail cost impacts:[25]
    - We received a limited number of confidential submissions that contained estimates of these COVID-19 cost impacts on retailers.
    - However, most submissions stated that there is too much uncertainty and that it is too early to be able to quantify a change in costs.
- A number of submissions noted the financial impact and cost burdens faced by small customers and recognised the broader government initiatives to assist customers, including the AER's Statement of Expectations. Some submissions did not support an increase or change to the DMO price at this time due to the impact this would have on consumers.[26]

2020, p. 1 – 3. AGL, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 2. Australian Energy Council, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 - 2.

25 Amaysim, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 4. Powershop/Meridian, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 2. 1st Energy, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1. ERM Power, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 2. iON Holdings, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 2. Simply Energy, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 – 3. AGL, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 2. Australian Energy Council, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020, p. 1 - 2.

26 Energy Consumers Australia, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 14 April 2020, p. 1. Public Interest Advocacy Centre, *Submission to impact of COVID-19 on the determination of the Default Market Offer, 9 April 2020*, p. 2., Quinbrook Infrastructure Partners/Cape Byron Power/Energy Locals/Energy Trade, Submission to impact of COVID-19 on the determination of the Default Market Offer, 9 April 2020, p. 4.

We greatly appreciate all the submissions received, especially in light of the time and resource pressures that all stakeholders are currently facing. We have carefully considered the matters raised in the submissions.

Based on the available information, we do not intend to make any adjustment to this DMO Final Determination in response to COVID-19. There are a number of factors we considered in reaching this position.

First, as noted in submissions, the current level of uncertainty about COVID-19 and limited information makes it difficult for us to forecast the cost impacts. While some submissions have provided estimates on cost impacts, these necessarily rely on various assumptions, extrapolations and limited data. Under the present circumstances there is a high risk that an ex-ante forecast of the COVID-19 impacts will be incorrect, especially given the dynamic nature of the issue. This could lead to consumers paying more than they need to or not provide the necessary incentives for retail competition and consumer participation.

Second, the information before us suggests that COVID-19 will have a limited impact on the DMO. This is due to the following factors:

- The limited information provided by stakeholders at this time suggests the COVID-19 cost impacts could be small in magnitude.
- The DMO price cap only applies to standing offer customers – this represents a limited proportion of small customers in the DMO regions; between 8 to12 per cent of residential customers and between 15 to 23 per cent of small business customers. Accordingly, the direct revenue at risk from the DMO for most retailers is limited.
- The DMO is designed to be set above observed market offers in order to not reduce incentives for market participation by customers and retailers, and allow retailers to recover their efficient costs. We note:
  - DMO prices are currently between $175 (SAPN) and $259 (Essential) above the median market offer for residential customers with no controlled load (CL).
  - DMO prices are currently between $242 (SAPN) and $330 (Essential) above the median market offer for residential customers with CL.
  - DMO prices are currently between $784 (Energex) and $1442 (Ausgrid) above the median market offer for SME customers.

  This indicates there is considerable scope to recover any incremental cost increases, for example through increasing the prices of market offers, without compromising the recovery of efficient costs[27] or exceeding the DMO price cap.

[27] We have generally used the median market offer as a proxy for what is likely to be the efficient costs of serving small customers in a distribution region.

Third, in assessing the potential cost increases identified, we have considered the impact of various COVID-19 policies, such as Commonwealth and State Government relief measures to financially support businesses and customers, and the Energy Networks Australia (ENA) relief package to defer or rebate network charges for affected customers. While these policy interventions may not fully mitigate the cost increases faced by retailers, they should have a direct impact on potential cost increases related to bad debt and other costs for managing financially vulnerable customers.

While our position is not to make an ex ante adjustment to our DMO Final Determination, this has not been a straightforward issue given the considerable uncertainty and paucity of information. We, along with other market bodies, will continue to closely monitor the impacts of COVID-19 on retailers and consumers.

Some submissions suggested a delay to our DMO Final Determination so that the uncertainty surrounding COVID-19 impacts can be better resolved.[28] We note this option is not open to us under the Regulations.[29]

A few submissions raised the need for some form of uncertainty mechanism or regulatory "re-opener" that could be used to adjust our 2020-21 DMO determination in light of market developments post 1 May.[30]

We agree that given the current uncertainties over future costs, there is merit in considering introducing a re-opener provision in the Regulations governing the DMO. We consider a re-opener provision would give the AER the scope to respond in a timely way to COVID-19, once all parties have a better understanding of the cost implications and the impact of the various policy measures being put in place now.

Given the nature of the DMO, a re-opener would be at the discretion of the AER and would only be implemented in response to a significant cost event. Reopening the DMO determination would require considerable effort by all stakeholders and would only be undertaken in response to a clearly identified need. It would function to reset the price cap on standing offers for the remainder of the regulatory period – that is, it would function prospectively to adjust the current DMO prices. The re-opener should be symmetric in that it would apply to material cost increases or decreases. As part of the re-opener process the AER could undertake some form of expedited consultation process.

We intend to explore these types of regulatory design issues with the Commonwealth Government and affected stakeholders, noting that any amendments to the Regulations are ultimately a decision for the Commonwealth Government.

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[28] Queensland Electricity Users Network, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 15 April 2020, p. 1 – 12.

[29] Regulations s.17

[30] For example, Australian Energy Council, *Submission to impact of COVID-19 on the determination of the Default Market Offer*, 9 April 2020.

3 DMO price determination

This chapter sets out our pricing methodology and reasoning for our DMO 2 price determination. It provides an overview of the DMO 2 pricing methodology, including our consideration of forecast changes in key cost components for 2020-21.

3.1 DMO 2 prices

DMO prices for 2020-21 for each customer type in each distribution region are set out in Table 4 below.[31]

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

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

Distribution region		Residential without CL	Residential with CL	Small Business without CL
Ausgrid	DMO 2 Price	$1,462	$2,024	$7,240
	for annual usage of	3,900 kWh	General usage 4,800 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 1	-$5 (-0.3%)	-$35 (-1.7%)	-$131 (-1.8%)
Endeavour	DMO 2 Price	$1,711	$2,165	$6,177
	for annual usage of	4,900 kWh	General usage 5,200 kWh + CL 2,200 kWh	20,000 kWh
	Difference to DMO 1	-$9 (-0.5%)	-$1 (0.0%)	-$27 (-0.4%)
Essential	DMO 2 Price	$1,960	$2,356	$8,041
	for annual usage of	4,600 kWh	General usage 4,600 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 1	+$3 (+0.2%)	-$19 (-0.8%)	-$4 (0.0%)
Energex	DMO 2 Price	$1,508	$1,812	$5,760
	for annual usage of	4,600 kWh	General usage 4,400 kWh + CL 1,900 kWh	20,000 kWh
	Difference to DMO 1	-$62 (-3.9%)	-$115 (-6.0%)	-$265 (-4.4%)
SAPN	DMO 2 Price	$1,832	$2,244	$8,305
	for annual usage of	4,000 kWh	General usage 4,200 kWh + CL 1,800 kWh	20,000 kWh
	Difference to DMO 1	-$109 (-5.6%)	-$176 (-7.3%)	-$815 (-8.9%)

In accordance with the Regulations, we have specified DMO prices as annual prices, based on the model annual usage (which incorporates annual usage and the timing and pattern of supply).[32] Under the Regulations, retailers must structure their tariffs to not exceed the DMO annual price for the model annual usage.[33] DMO prices are not a 'maximum bill'. Individual customer 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.

3.2 Pricing methodology for DMO 2020-21

This section outlines our pricing methodology for determining DMO 2 prices.

Our Draft Determination position

Our proposed pricing methodology in the Draft Determination involved adjusting the DMO 1 prices to reflect forecast changes in wholesale, environmental and network costs. The residual costs (including retail costs) were to be adjusted according to changes in the Australian Consumer Price Index (CPI).

We also proposed a step change assessment framework to pass through any exogenous, material change to retail costs not reflected in the DMO 1 price.

Underlying this approach was our view that the DMO 1 prices had appropriately balanced the DMO policy objectives and are an appropriate starting point for setting DMO 2 prices.

Stakeholder submissions

Retailer submissions generally supported our approach to setting prices for DMO 2. In particular, Alinta Energy, 1st Energy, Origin Energy, EnergyAustralia, AGL and the AEC supported the DMO 2 approach of indexing DMO 1 prices to take account of changes in costs.[34] The AEC and EnergyAustralia noted the approach successfully balances the requirements for a safety net for disengaged customers and encouraging retail innovation and customer participation in the market.[35]

Alinta Energy considered the DMO is harmful to competition and encouraged the AER to continue to monitor the market.[36] 1st Energy noted price regulation is intrinsically intrusive[37], and Origin noted regulated prices pose risks from regulatory error to the

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32 Regulations, s. 16(1).

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

34 Alinta Energy, *Submission to DMO 2 Draft Determination,* 9 March 2020, p. 1; 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1; EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 1; AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 1; Australian Energy Council (AEC), *Submission to D1MO 2 Draft Determination,* 10 March 2020, p. 1.

35 Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 1; EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 1.

36 Alinta Energy, *Submission to DMO 2 Draft Determination,* 9 March 2020, p. 1.

37 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1.

efficient operation of the market.[38] Powershop/Meridian supported the AER's approach to DMO 2 in principle, but considered it does not enable retailers to fully recover their efficient costs, restricting their ability to innovate.[39]

As the DMO has been in effect for less than a year we consider it is 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. Since the introduction of the DMO, we have observed reductions in the median market offer, and a move away from conditional discounts. We also note that more than 95 per cent of market offers are priced at or below the DMO. However, we continue to monitor the market. Refer to **Appendix B** for further information.

We received submissions from three consumer representatives: Energy Consumers Australia (ECA), Queensland Council of Social Services (QCOSS) and its consultant Etrog Consulting, and the Public Interest Advocacy Centre (PIAC).

PIAC and QCOSS did not support our approach for DMO 2 of indexing costs using DMO 1 as a base.

Both groups considered the DMO 1 price has not met the objectives set out in the ACCC's REPI report, which they considered are to establish a price at the level of retailers' efficient costs. The groups considered that by explicitly setting the DMO price at a level above efficient costs, the DMO price was inherently excessive. They considered the DMO price should be set at the level of efficient costs, based on a bottom-up assessment of retailers' costs, including retail costs such as customer acquisition and retention, profit margin and competition headroom.

While supporting the principle of a default price mechanism, PIAC was concerned DMO 1 and DMO 2 did not provide sufficient protection to standing offer customers. PIAC considered a DMO set closer to the level of efficient costs would better meet the DMO policy objectives, including to remove unjustifiably high prices and incentivise competition and innovation.[40]

Similarly, QCOSS/Etrog Consulting suggested the AER has failed to meet the DMO policy objectives of protecting standing offer customers from excessively high prices.

QCOSS noted a lack of transparency in the residual retail component of our cost stack, and supported a rigorous assessment of this component.

QCOSS submitted that consumers have been under-represented in the development of our DMO 2 process, noting the 'proportion of supportive submissions should not be

[38] Origin Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1.

[39] Powershop/Meridian, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1–2.

[40] Public Interest Advocacy Centre (PIAC), *Submission to DMO 2 Draft Determination,* 12 March 2020, p. 1–3.

considered a proxy for the level of support from the community for the AER's determination'.[41]

QCOSS stated that the AER should better explain the DMO for a consumer audience.[42]

QCOSS also considered the DMO price should be extended to all customers, particularly those on legacy market offers.[43]

ECA considered energy businesses should drive cost reductions to customers having a detailed understanding of their costs and the implications of reductions for their businesses. They did not comment on the DMO 2 pricing methodology, noting only that it should deliver price reductions in all jurisdictions.[44]

The matters the AER must have regard to in setting the DMO are specified under section 16(4) of the Regulations. We have also 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.[45]

We consider our approach meets all the relevant policy objectives for the DMO and criteria set out in the Regulations (refer to **Appendix E**). To meet these objectives we set the DMO 1 price at the 50th percentile of the range between the median standing offer and median market offer in each distribution region. Based on our analysis and the available evidence, we are satisfied that the DMO 1 prices balanced the policy objectives of:

- *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 as a reasonable indication of retailers' efficient costs.
- *not reducing incentives for innovation, investment, competition and market participation by customers and retailers* – We considered setting the DMO price above the level of efficient costs provides opportunity for retailers to compete, and incentives for customers to participate in the market by shopping around for an offer that suits their needs. The DMO 1 price was set higher than most

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41 Queensland Council of Social Service Inc (QCOSS), *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

42 Energy Consumers Australia (ECA), *Submission to DMO 2 Draft Determination,* 13 March 2020, p. 1–3; Etrog consulting (on behalf of Queensland Council of Social Service Inc), *Submission to DMO 2 Draft Determination,* 9 March 2020, p. 1–21.

43 Queensland Council of Social Service Inc (QCOSS), *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

44 Energy Consumers Australia (ECA), *Submission to DMO 2 Draft Determination,* 13 March 2020, p. 1 – 3.

45 ACCC, *Retail Electricity Pricing Inquiry 2017-2018*, final report, June 2018.

market offers in each distribution region, meaning customers on a DMO should have an incentive to shop around and switch.

Our pricing methodology for DMO 2 is intended to maintain this balance, by making adjustments for the forecast changes in costs in 2020-21.

The decision to set the DMO price above the level of efficient costs is consistent with the policy objectives of the Regulations and the REPI report. In its submission to the DMO 1 Draft Determination, the ACCC repeated this intention for the DMO to be set above efficient costs, noting the DMO price should not aim to be the lowest priced offer or be set at the efficient level, but rather act as a 'reasonable fall-back position for those not engaged in the market for whatever reason or for those that require its additional protections'.[46]

Altering the policy objectives of the DMO are matters outside the AER's role in setting DMO prices. We note the Government has planned a post-implementation review of the Regulations after two years[47], and stakeholders wishing to raise matters regarding altering policy objectives may wish to have them considered in this process.[48]

We recognise our Final Determination is necessarily technical in nature. Our communications material accompanying this determination provides an explanation for a non-technical audience, with a brief description of what the DMO is and a snapshot of DMO prices in each region.

During this determination process we have consulted widely with a range of stakeholders to ensure we have regard to a broad range of views in making this determination. However, we recognise the limited number of submissions received from consumer representatives to our Draft Determination should not be taken as broad acceptance of our approach.

We continually seek to provide opportunities for consumer representatives to input into our processes, and also recognise stakeholders may have different preferences for providing input. To facilitate this, we provided stakeholders with various means to share their views, including in face-to-face and teleconference meetings, during our webinar and via written submissions. For future DMO determinations we will continue to seek ways to make it easier for stakeholders to provide input into our determinations.

46 ACCC, *AER Default Market Offer, Submission to the Draft Determination*, 20 March 2019, p. 1 – 2: https://www.aer.gov.au/system/files/ACCC%20-%20AER%20Default%20Market%20Offer%20-%20Submission%20to%20Draft%20Determination%20-%2020%20March%202019.PDF

47 *Regulations, Explanatory statement:* https://www.legislation.gov.au/Details/F2019L00530/Explanatory%20Statement/Text

48 *Competition and Consumer (Industry Code - Electricity Retail) Regulations 2019, Explanatory statement,* 4 April 2019: https://www.legislation.gov.au/Details/F2019L00530/Explanatory%20Statement/Text

Final Determination

Consistent with our Draft Determination, we have adopted an approach of indexing the DMO 1 price to account for forecast changes in wholesale energy, network and environmental costs, while increasing the residual component by CPI.

3.3 Forecast changes in cost inputs in 2020-21

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 5 below.

Table 5: Forecast changes in cost components and DMO bill impact – 2019-20 to 2020-21 (incl GST, nominal)

Description	Network cost	Wholesale cost	Environ-mental cost	Overall price impact from DMO 2019-20 (%, $)		DMO 2020-21
Residential without CL						
Ausgrid	+1.8%	-0.3%	-20.8%	**-0.3%**	*-$5*	**$1,462**
Endeavour	-1.9%	+3.4%	-20.4%	**-0.5%**	*-$9*	**$1,711**
Essential	+1.9%	+0.3%	-21.1%	**+0.2%**	*+$3*	**$1,960**
Energex	-1.1%	-7.0%	-24.9%	**-3.9%**	*-$62*	**$1,508**
SAPN	-5.6%	-6.1%	-21.7%	**-5.6%**	*-$109*	**$1,832**
Residential with CL						
Ausgrid	+1.9%	-2.9%	-20.8%	**-1.7%**	*-$35*	**$2,024**
Endeavour	-0.8%	+3.9%	-20.4%	**0.0%**	*-$1*	**$2,165**
Essential	+2.0%	-1.9%	-21.1%	**-0.8%**	*-$19*	**$2,356**
Energex	-5.4%	-6.8%	-24.9%	**-6.0%**	*-$115*	**$1,812**
SAPN	-6.3%	-8.1%	-21.7%	**-7.3%**	*-$176*	**$2,244**

Description	Network cost	Wholesale cost	Environ-mental cost	Overall price impact from DMO 2019-20 (%, $)		DMO 2020-21
Small business without CL						
Ausgrid	-2.8%	-0.3%	-20.8%	**-1.8%**	*-$131*	**$7,240**
Endeavour	-1.4%	+3.4%	-20.4%	**-0.4%**	*-$27*	**$6,177**
Essential	+1.7%	+0.3%	-21.1%	**0.0%**	*-$4*	**$8,041**
Energex	-1.1%	-7.0%	-24.9%	**-4.4%**	*-$265*	**$5,760**
SAPN	-13.9%	-6.1%	-21.7%	**-8.9%**	*-$815*	**$8,305**

Note: Overall price impact includes residual cost adjusted for CPI (1.75%) in 2020-21

The key drivers for these changes are:

- Wholesale costs comprises **wholesale energy costs** associated with hedging and spot market costs, as well **as other energy costs** incurred in participating in the NEM wholesale market.[49] The overall impact of the forecast changes in **wholesale energy costs** and **other energy costs** is presented in the Wholesale cost column in table 5 above.

  The key drivers in the change in **wholesale energy costs** are the change in contract prices and shape of the load profiles. Our Consultant notes that, compared with the 2019-20, futures base contract prices for 2020-21, on an annualised and trade weighted basis to date have:

  - decreased by about $5.70/MWh for Queensland
  - decreased by about $5.00/MWh for New South Wales
  - decreased by about $10.30/MWh for South Australia.

  There are two main drivers for this:

  - the strong increase in renewable investment coming on-line between 2019-20 and 2020-21, with about 5,200 MW of renewable investment entering the NEM over the next 18 months
  - the reduction in gas prices for gas fired generation. Spot prices across the east coast gas market have declined over the past 12 months from levels near, and often above, $10/GJ. This has been due to a range of factors including reduced gas fired generation demand, improved supply

[49] Other energy costs includes costs for services such as the Australian Energy Market Operator (AEMO) charges and ancillary service charges for services to manage power system safety, security and reliability.

performance from CSG fields in Queensland, and reduced international LNG export prices.

Wholesale energy costs for the NSW regions are forecast to decrease slightly (Ausgrid and Essential) or increase (Endeavour) between 2019-20 and 2020-21. The expected increase in uptake of rooftop solar in NSW (where solar uptake is low compared with other regions) has resulted in a peakier load forecast in this region, which increases the cost to hedge. This factor has led to smaller declines in forecast costs in NSW compared with SE Queensland and South Australia. The forecast increase in wholesale energy costs for Endeavour's region is due to the time of day load profile shape exhibiting a higher degree of volatility compared with other regions in NSW.

The stronger decrease in wholesale energy costs for Queensland and South Australia compared with NSW also result from stronger declines in contract prices and less change in the demand profiles given the existing penetration of rooftop solar in these two regions.

The change in wholesale energy costs for the controlled load customers varies across the regions – with some increasing slightly, and others decreasing by up to 15 per cent between 2019-20 and 2020-21.

Other energy costs are forecast to increase across most distribution regions between 2019-20 and 2020-21. The most significant change in other energy costs are the costs associated with ancillary services, which on average have tripled in all regions for all tariff types. Higher ancillary services costs result from several events that occurred over the most recent 12 months, including the unplanned VIC-SA interconnector outage in January 2020, and the islanding of South Australia in November 2019. The cost variations by region also result from the differences in the cost associated with the Reliability and Emergency Reserve Trader (RERT) mechanism.

- **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 49 per cent because of a surge in renewables investment for the coming year to reach the 2020 LRET target. The cost of SRES is projected to increase by 1 per cent, with the expectation that small-scale installations (rooftop solar and solar water heaters) will increase slightly in 2021. The cost variations by region mainly result from differences in jurisdictional energy efficiency schemes.
- **Network costs** vary across the regions by customer and tariff type. Energex and SAPN regions are currently undergoing revenue determination resets. The changes observed in these regions result from shifting from one regulatory period to the next. In Energex's region, decreases in network tariffs have been largely offset by the addition of jurisdictional scheme costs, following the

inclusion of the Solar Bonus Scheme (SBS) and the Australian Energy Market Commission (AEMC) levy.[50]

For regions within a regulatory control period (NSW regions), the revenues are smoothed across the period allowing for relatively predictable network price movements. Changes to yearly revenue of the distribution and transmission businesses 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. The network costs for all customers in NSW regions are forecast to change between a 3 per cent decrease to a 2 per cent increase in 2020-21.

- **Residual costs** increased by 1.75 per cent across all regions based on the RBA's February 2020 Consumer Price Index inflation forecast for the 2020-21 period. Our analysis and consideration of submissions has not identified any increase or decrease in retail costs that would warrant a step change.

Each of these cost components is discussed in detail below.

A detailed assessment of the wholesale and environmental cost forecasts, including inputs provided by the Consultant and issues raised in submissions, is provided in the Consultant's report.

3.3.1 Wholesale

Overview

The electricity purchase price faced by 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 services charges for services to manage power system safety, security and reliability.

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50 On 15 March 2020, the Queensland Government announced it would pay a $50 Asset Ownership Dividend (AOD) for all residential customers in 2020 (continuing AOD payments made in 2018 and 2019).

Our Draft Determination position

In the Draft Determination we adopted a market based approach for the assessment of wholesale costs, making use of financial derivative data. This approach has three key parts.

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

   Our Consultant assessed the possibility of separating the NSLP into small business and residential profiles. 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 regions are on smart meters. Therefore, there is insufficient data in Queensland, NSW and SA to effectively split the NSLP into residential and small business profiles.

2. **Hedging 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 price. 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 to 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 with pricing and volume information, and extend up to 3 months before the beginning of a determination period.

3. **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 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.

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 hedge book, 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

Retailer submissions were generally supportive of the market based approach to forecasting wholesale energy costs.[51]

1st Energy, AGL and Origin Energy sought clarification on the treatment of the Reliability and Emergency Reserve Trader (RERT) mechanism under our energy cost forecasting approach.[52]

The RERT mechanism allows Australian Energy Market Operator (AEMO) to contract for and activate emergency reserves such as generation or demand response to counteract critical shortfalls. RERT costs are initially incurred by AEMO and are subsequently recovered from market participants, with event based, quarterly and annual reporting of activated responses and costs incurred. It is difficult to forecast the cost of RERT into the future as it acts as a safety net and mechanism of last resort that is only called upon under extreme circumstances.

Due to the delay in costs incurred by AEMO and the subsequent recovery from retailers, and difficulty in forecasting RERT costs, our approach takes RERT costs as published by AEMO for 2018-19 year and applies it to the 2019-20 DMO wholesale energy cost forecast. For the identification of the 2020-21 DMO RERT cost, we used the latest available published data from AEMO, which includes the summer months of

[51] 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1; AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 1 – 2; Origin Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1.

[52] AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2; Origin Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

2019-20. With the passage of the peak summer months, it is unlikely RERT will be activated again in the 2019-20 period.

Under this approach:

- RERT costs are included for South Australia in the 2019-20 DMO wholesale energy cost forecast resulting from RERT costs incurred in the 2018-19 period
- no RERT costs are included for South Australia in the 2020-21 DMO wholesale energy cost forecast as RERT was not triggered and unlikely to be triggered in South Australia in the 2019-20 period
- RERT costs are included for NSW in the 2020-21 DMO wholesale energy cost forecast as RERT was triggered in January of 2020 in NSW.

Powershop/Meridian prefer to split residential and small business customer usage profiles.[53] As per our Draft Determination, we note there is insufficient data in Queensland, NSW and SA to effectively split the profiles for residential and small business customers. Further, 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. We will continue to monitor the availability of smart meter data in DMO regions in future determinations.

Energy Australia submitted the AER's approach needs to sufficiently consider the uncertainties involved in estimating wholesale energy costs.[54] It noted that estimates of wholesale energy costs from different consultants could materially diverge.

We consider our wholesale energy cost forecasting approach is conservative and appropriately accounts for the uncertainties in forecasting. The forecasting methodology takes into account appropriate contract weightings, and 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. Our Consultant ran over 500 simulations of demand and spot price outcomes, along with the application of contracting strategies, and has based its estimate of wholesale energy costs at the 95th percentile of the distribution of all outcomes. That is, the wholesale energy cost used is exceeded by only 5 per cent of the simulated wholesale energy costs outcomes.

Energy Consumers Australia submitted that it was surprised by the DMO price increase in the NSW regions resulting partly from higher wholesale energy costs, given the AEMC has forecast a decrease in costs.[55] Differences in load profiles, supply scenarios, approaches to account for uncertainty and risk, and the market data and cut-off date used will affect the wholesale energy forecast. In addition, the particular forecasting approach chosen is informed by the purpose of the task and relevant policy

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53 Powershop/Meridian, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1 – 2.

54 EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 6 – 7.

55 Energy Consumers Australia (ECA), *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 2.

objectives. The AER has different objectives than other agencies. These factors are likely to explain the difference in our Draft Determination compared with other wholesale energy cost forecasts. The Consultant's report includes a section that discusses methodological differences between its modelling and the AEMC's. The key differences relate to the treatment of spot market modelling, demand profiles and assumptions about retailer hedging.

Final Determination

Our Final Determination approach is to use a market based approach (using financial derivative data) to forecast 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.

This is consistent with the approach applied in our Draft Determination, but we have used updated market data up to 25 March 2020.

For more information on the approach and consideration of the submissions to the Draft Determination, see the Consultant's report.

The wholesale cost inputs provided by the Consultant are given in Table 6 below.

Table 6: Wholesale costs for 2019-20 and 2020-21, $/MWh (excl GST, nominal).

Distribution region	Tariff	2019-20	2020-21
Ausgrid	Flat rate	111.36	111.06
	CL1	84.15	74.02
	CL2	79.64	72.11
Endeavour	Flat rate	108.61	112.27
	CL1	98.59	103.92
	CL2	98.59	103.92
Essential	Flat rate	103.17	103.50
	CL1	95.11	87.90
	CL2	95.11	87.90
Energex	Flat rate	98.34	91.49
	CL1	72.52	72.29
	CL2	80.97	74.06
SAPN	Flat rate	164.21	154.12
	CL1	109.65	93.15

Source: Consultant report

3.3.2 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.[56] 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).[57]

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 – these are included in our forecasts of network costs, discussed below. 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.[58]

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

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

58 ACIL Allen estimate the cost of the ESS by applying the estimated ESS target to the ESC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2019-20 and 2020-21. ACIL Allen take REES costs from the AEMC Price Trends report. For more information on these costs see the Consultant Report.

Our Draft Determination position

Our Draft Determination approach included 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

Origin Energy supported our overall approach to estimating environmental costs, stating that it supports 'the approach applied by ACIL with respect to renewable energy costs'.[59]

Nearly all retailers supported our approach to estimating SRES costs.[60] Specifically, retailers supported ACIL Allen's approach to providing its own STP estimates where STP values were non-binding.

AGL, EnergyAustralia, and the AEC raised concerns with our approach to estimating LRET costs. They suggested our approach using LGC forward prices is not representative of the actual cost that retailers incur as per their respective PPAs with large-scale renewable energy generators, or internal investment in renewable energy generation units for vertically integrated companies.[61]

AGL suggested alternative approaches to estimating LGC prices, such as:

- avoiding a downward adjustment as PPA costs are unchanged, or
- modelling costs based on historical PPAs, or
- applying a floor price to LGCs.[62]

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59 Origin Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

60 Origin Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2. 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1. AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2. Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2.

61 AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2. EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 1 – 6. Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2.

62 AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2.

In our Draft Determination, we identified the complexities in determining a benchmark LGC price through the use of PPA information. We noted the various forms, durations and commercial drivers for these arrangements and the challenges this would create for estimating a benchmark LGC price for a specific regulatory period. We acknowledge 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 currently.

Energy Australia stated that the market based approach does not represent retailer practice.[63] We recognise that there are retailers that 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, not all retailers are in a position to be able to enter into PPAs and make use of other hedging methods, as Powershop notes in its submission.

The CER's latest Carbon Market Report[64] shows that LGCs trade reasonably well in the market. For example, LGC market trades during calendar year 2019 amounted to over 69 million LGCs, or over two times the mandated LRET target for 2019. In addition, analysis by our Consultant shows that TFS-brokered forward contracts for calendar year 2019, since they commenced trading, comprise around 40 per cent of the LRET target for 2019. If 2019 spot trades are included, then this share increases to around 53 per cent. This indicates that the broker data used in estimating LGC prices in this determination is robust and representative of the broader LGC market.

Therefore, we maintain the view that LGC brokerage prices that are transparent, publicly available and a function of market conditions, are the best available proxy for assessing the cost of acquiring LGCs. Given this we do not consider AGL's alternative methodologies would provide a more robust estimate of LRET costs.

EnergyAustralia submitted that our market-based LGC estimates are out of line with cost trends from other recent regulatory decisions by ICRC and ESCV.[65]

We understand ICRC's model[66] determines LGC prices based on publicly available spot price data averaged over an 11-month period. Our view is that using forward prices for each relevant estimation period will provide a more accurate representation of the costs incurred within the period than using historical spot prices.

ESCV estimated an LGC price in November 2019 for its VDO final determination using a volume-weighted average of LGC future trades for 2020. We have considered the use of a volume-weighted average compared with the use of a simple average of LGC

63 EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p.3.

64 Clean Energy Regulator, *Quarterly Carbon Market Report,* February 2020.

65 EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 5 – 6.

66 Independent Competition and Regulatory Commission, *Draft Report – Electricity Price Investigation 2020-24, 4* February 2020, p. 21 – 24.

forward prices over two years. Our Consultant compared the two methodologies and a third methodology – a volume-weighted average since trading began (October 2016 for 2019 LGCs, and May 2017 for 2020 and May 2018 for 2021 LGCs). We consider this third methodology is likely to be the most robust as it takes into account the entire time period in which trades occur. We have therefore adopted this methodology to estimate LGC prices for our Final Determination.[67]

Final Determination

In response to our Draft Determination submissions and further analysis, we have refined our approach to estimating LGC prices. We will use a volume-weighted average of LGC forward prices since trading commenced.

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

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

The jurisdictional energy efficiency schemes, and network losses (that impact environmental cost forecasts) vary between distribution regions. As a result, the total forecast environmental costs ($/MWh) are different across regions. See Table 7 below.

67 Results from using a volume-weighted average since trading commenced showed a slightly higher cost for LGCs than using a simple average over a 2 year period.

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

Distribution region	Tariff	2019-20	2020-21
Ausgrid	Flat rate	21.68	17.17
	CL1	21.77	17.22
	CL2	21.77	17.22
Endeavour	Flat rate	21.81	17.36
	CL1	21.81	17.36
	CL2	21.81	17.36
Essential	Flat rate	21.87	17.25
	CL1	21.87	17.25
	CL2	21.87	17.25
Energex	Flat rate	20.10	15.10
	CL1	20.10	15.10
	CL2	20.10	15.10
SAPN	Flat rate	23.72	18.57
	CL1	23.72	18.57

Source: Consultant report

3.3.3 Network costs

Overview

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 the distribution network businesses annually set for customer use of the network. Network tariffs are typically constituted of two components.

- 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 recovered across the entire customer base.
- Metering charges relating to the distribution network businesses' installation and maintenance of type 5 manually-read interval meters and type 6 accumulation meters.

Draft Determination

In the Draft Determination we noted retailers typically pass through the applicable network tariff to their customers. To assess the changes in network costs in 2020-21 we proposed the following approach:

- for networks within a network regulatory control period, use the indicative network tariffs from the last available annual pricing proposals. In 2020-21, this would apply to Ausgrid, Endeavour and Essential Energy
- for networks undergoing a network revenue reset, use the final revenue determination changes in revenue as the best available information for network cost forecasts. We noted that it may be possible to take into account material network revenue and non-network cost drivers. In 2020-21, this would apply to Energex and SAPN.

Aside from the above approaches, we proposed:

- for Ausgrid, not to adjust the DMO 1 price for the impact of the remittal decision on the 2019-20 tariffs
- for Energex, if the funding arrangements for the Solar Bonus Scheme (SBS) costs were to change such that distribution network businesses become responsible for recovering costs from their customers, we would adjust our assessment to take this into account.

Stakeholder submissions

Stakeholders supported our approach of using annual pricing proposals to assess network costs for distribution networks within a regulatory control period. However, the majority of submissions noted that using annual revenue changes for networks undergoing a revenue reset would not reflect the changes in actual costs incurred by retailers.[68] This is because each customer type may be affected differently, both in total revenue and in tariff components (daily charge and usage charge).

We note the final annual pricing proposals for networks undergoing a revenue reset (SAPN and Energex for 2020-21) are submitted after our DMO Final Determination. Given this constraint, there are two main options for estimating network costs:

- use the indicative tariffs from the revised regulatory proposals, or
- use the annual revenue changes in the relevant final network revenue determination.

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68 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1; AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 3 – 4; Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination*, 10 March 2020, p. 1 – 2; EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 9 – 10; Powershop/Meridian, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2; Alinta Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1.

Most stakeholders recommended using the indicative tariffs from the revised regulatory proposals. We used these for assessing network costs in our Draft Determination.[69] A few stakeholders suggested including a risk or contingency allowance if we were to use changes in revenue.[70] If we were to use the changes in revenues in the final network revenue determination, Origin Energy and AGL suggested we consider the impact of revenue changes to different tariffs. This could be achieved by engaging directly with Energex and SAPN.

We note both the approaches – the one using indicative tariffs from revised regulatory proposals and the other using revenue changes from final decisions – have their benefits and shortcomings.

Revenue decisions set caps on a distribution or a transmission network business' revenue for a forward-looking five year period. The process is lengthy and consultative. The final network revenue determinations provide the latest AER approved annual revenue. However, they do not incorporate any tariff rebalancing, which involves changing the revenue allocation across different tariff classes and components. Also, the revenue decisions do not include information on jurisdictional schemes.

The indicative tariffs in the revised regulatory proposals are submitted by the distribution network businesses in response to draft network revenue determinations published by AER. Therefore, they do not reflect the latest AER approved annual revenue. The tariffs include costs associated with Distribution Use of System (DUOS), Transmission Use of System (TUOS) and jurisdictional schemes. The distribution network businesses are able to include information related to any tariff rebalancing and may also include estimates of other network cost drivers not reflected in the revenue decisions. These proposals are also required to include indicative charges associated with the jurisdictional schemes.

We have decided to use the indicative tariffs from the revised regulatory proposals to assess changes in network costs in the regions undergoing resets, as these will reflect the likely tariff structures and include other cost information.

Alinta Energy supported our position that should the Queensland Government make changes to its subsidy for the jurisdictional Solar Bonus Scheme (SBS), this would be incorporated in the DMO 2 prices in the Final Determination.

The indicative tariffs in Energex's revised regulatory proposal do not contain any jurisdictional scheme costs. However, we have considered the information published by the Queensland Competition Authority (QCA) in its draft determination for

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69 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1; AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 3 – 4; Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination*, 10 March 2020, p. 1 – 2; EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 9 – 10.

70 Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination*, 10 March 2020, p. 1 – 2; Powershop/Meridian, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2; Alinta Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1.

Regulated Retail Electricity Prices for regional Queensland for 2020-21 (published on 31 March 2020). The QCA notes it received advice from Energy Queensland (EQ) of its intention to include jurisdictional scheme amounts, which include SBS and Australian Energy Market Commission (AEMC) levy costs, in the Ergon and Energex annual network pricing proposals.[71] Since these costs were not provided in the revised regulatory proposal submitted by Energex, we have added these costs to our network cost assessment for the Energex distribution region.[72]

Final Determination

Our network costs forecasts for 2020-21 are based on the following sources:

- New South Wales: For Essential, we have used the NUOS tariffs and metering charges from the 2020-21 annual pricing proposal submitted by the distribution network business. The 2020-21 annual pricing proposals received from Ausgrid and Endeavour had incorporated changes in forecast demand that the AER was still assessing at the time of finalising this Final Determination. Therefore, we consider the indicative NUOS tariffs and metering charges for 2020-21 from the 2019-20 annual pricing proposals approved by the AER provide the best available information for expected changes in network costs in these regions.
- South East Queensland: We have used the indicative NUOS tariffs and metering charges from the revised regulatory proposal submitted by Energex as part of the 2020-25 revenue reset, plus the jurisdictional scheme charges outlined in the QCA's draft decision for Regulated Retail Electricity Prices for regional Queensland for 2020-21.
- South Australia: We have used the indicative NUOS tariffs and metering charges from the revised regulatory proposal submitted by SAPN as part of the 2020-25 revenue reset.

The network tariffs for the Final Determination and their sources are given in **Appendix D3**.

3.3.4 Residual costs and the step change framework

Overview

Retail costs are incurred by retailers to acquire, service and retain customers, including meeting regulatory obligations.[73] These costs plus a retail profit margin form the residual cost component of our DMO price.[74]

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71 QCA, *Regulated retail electricity prices for 2020–21 – Draft Determination*, March 2020, p. 17.

72 QCA, *Technical appendices – Regulated retail electricity prices for 2020–21 – Draft Determination*, March 2020, p. 17.

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

74 Residual costs for the 2019-20 period is worked out as the DMO 1 price less wholesale, environmental and network costs for a distribution region and tariff type.

Our approach to forecasting retail cost changes is to identify the residual costs in DMO 1 prices after wholesale, environmental and network costs are deducted, and index these costs by the change in the forecast Consumer Price Index (CPI).

We also have a step change framework to assess specific adjustments to retail costs, either cost additive or subtractive. 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.

Draft Determination

Our Draft Determination approach updated the DMO 1 residual costs for the forecast change in CPI between 2019-20 and 2020-21 of 1.85 per cent.

We considered potential step changes for regulatory changes such as five minute settlement, the Retailer Reliability Obligation (RRO) and Consumer Data Right (CDR) obligations. We did not find any evidence to warrant a step change in costs for any of these regulatory changes.

Stakeholder submissions

Retailers and consumer groups took opposing views on the approach of indexing residual costs by CPI. Most retailer submissions were either supportive or silent on the methodology of indexing the residual cost by CPI[75], though many suggested an upward adjustment to the retail cost should be applied to account for regulatory changes. Consumer groups disagreed with the application of CPI to forecast changes in residual costs as it does not reflect efficiency and productivity improvements.

Specific feedback from submissions included the following:

- AGL noted there are many significant changes and proposals affecting the energy retail environment with material cost impacts. AGL does not separately account for each of the step changes and accepts that increasing the residual cost by CPI is appropriate without an explicit cost assessment.[76]
- Alinta Energy wants the AER to take account of the cumulative cost of regulatory changes including: personnel, IT, compliance, co-ordination of generation and transmission investment, two-sided markets, post-2025 market

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[75] AGL, *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 4.

[76] AGL, *Submission to DMO 2 Draft Determination*, 10 March 2020, p. 4.

design. Further, Alinta Energy requested the AER adopt a benchmarking approach to take account of additional costs in the step change framework, because providing AER information to substantiate step changes is costly.[77]

- Powershop/Meridian stated a CPI adjustment for the residual component risked underestimating the change in costs due to the ongoing costs of innovation. It stated there is a lack of evidence a CPI adjustment would cover costs such as peer-to-peer trading, virtual power plants and demand response. It noted the AER has only considered five-minute settlement, consumer data right and the retailer reliability obligation in relation to its step change framework. It submitted there are other innovations and associated costs the AER should consider under this framework, including numerous rule changes introduced by the AEMC over 2019-20.[78]
- Origin Energy expressed its disappointment with AER's decision not to include a step change increase in retail costs for the cost of five-minute settlement in the DMO price. It considered the AER has an obligation to determine a DMO price that does not underestimate a retailer's actual costs.[79]
- Vector proposed the AER include the costs of installing advanced meters as a retail cost component in the DMO, and in forecasting changes to input costs.[80] Our consideration and position on metering costs are discussed in the section 4 of this Determination, in the discussion on advanced meters.
- QCOSS/Etrog Consulting disagreed with the use of CPI to index retail costs from DMO 1 and submitted the AER should apply productivity improvements to the DMO. It further submitted the AER should not approve costs through its step change framework before it has developed a method for identifying and analysing negative step changes in costs, and applying productivity improvements to retailers' costs.[81]
- ECA submitted the retail cost component should be flat or reduced instead of increasing by CPI. It noted the ACCC found retail costs decreased between 2013 and 2018 by $20.[82]

The methodology used to determine DMO 2 is an extension of the top-down methodology used to determine the DMO 1 prices. Our approach to estimating the residual costs involves two steps:

- calculating the residual component in 2019-20 by deducting forecast wholesale, environment and network costs from the DMO 1 price

77 Alinta Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 1 – 2.

78 Powershop/Meridian, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

79 Origin Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2 – 3.

80 Vector, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 4 – 5.

81 Queensland Council of Social Service Inc (QCOSS), *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2 – 3; Etrog consulting (on behalf of Queensland Council of Social Service Inc), *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 12 – 15.

82 Energy Consumers Australia (ECA), *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 3.

- indexing this residual component by forecast CPI to forecast the residual component in 2020-21.

This approach has the benefit of maintaining the residual cost component of the DMO price at current levels in real terms. Our view is that this level of residual costs has met the DMO policy objectives as part of DMO 1, including enabling retailers to recover their efficient costs. Therefore, absent any significant changes to retail costs, this approach will produce a forecast of the residual costs for 2020-21 that is consistent with the criteria under the Regulations and the DMO policy objectives. In the case where retail costs are materially impacted by exogenous factors such as new regulatory obligations, there is scope to apply step changes to the residual cost component.

In our Draft Determination we invited stakeholders to provide evidence, justification and any cost information for potential step changes, including regulatory changes such as five minute settlement. There was no evidence or detailed justifications for any step changes included in the submissions. Origin Energy did not submit additional information to further substantiate the cost impacts of five minute settlement. Alinta Energy noted that substantiating costs resulting from step changes is a costly exercise. While understanding that it is costly to provide evidence, the cost of producing cost estimates and justifications should be a small proportion of any material cost incurred as a result of step changes.

As explained in our Draft Determination, we considered the costs of implementing five minute settlement based on the information provided by retailers. We found there was insufficient evidence to indicate an adjustment to the residual cost is needed. We received no further evidence or information to alter this view.

On 7 April 2020, the three energy market bodies - the AER, AEMC and AEMO - wrote to the Commonwealth Minister for Energy and Emissions outlining an agreed set of objectives and criteria for considering altering the implementation dates for some key market reforms and rule changes due to COVID-19. Part of this was a proposal to provide industry with a 12 month delay to the remaining expenses associated with five minute settlement.[83]

We note the Retailer Reliability Obligation (RRO) was triggered in South Australia, with the obligation starting in 2021-22. Given this is outside of the relevant DMO 2 period, the assessment of the cost impact of the RRO will be made as part of the DMO 3 Determination process.

The timing of the implementation of the Consumer Data Right (CDR) and the detailed scope of the data sets to be included is still to be confirmed. The Treasury has not released any further updates on the scope of the energy CDR since the release of the Draft Determination. Noting this, we consider the CDR obligation is unlikely to have a

83 See letter at: https://www.aer.gov.au/system/files/prioritising-implementation-timeframes-for-rule-changes-covid-19-response.pdf

material cost impact for the 2020-21 period. Assessment of the cost impact of the CDR obligation will be made as part of the DMO 3 Determination process.

We note the submissions from QCOSS/Etrog and ECA that residual costs should not be indexed by CPI. We acknowledge that improvements in technologies and processes should drive productivity and this could be reflected in how we forecast residual costs. We will consider this for future determinations, noting a robust quantification of any productivity factor would require relevant data. In the absence of detailed information, an alternative may be to apply a simple type of stretch factor. We consider applying CPI for this Final Determination is a reasonable approach given the policy objectives of the DMO and the relatively high threshold for implementing any step changes in retail costs.

Final Determination

Our Final Determination approach is to index the DMO 1 residual costs for the forecast change in CPI between 2019-20 and 2020-21 by 1.75 per cent.[84]

Our analysis and consideration of submissions has not identified any increase or decrease in retail costs warranting a step change.

[84] The CPI inflation applied to the DMO 2 time period is published in the RBA's output growth and inflation forecasts for year-ended June 2021, from the RBA's February 2020 Statement of Monetary Policy.- Economic Outlook

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 price 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.[85] The Regulations refer to these elements in combination as the 'model annual usage'.

In February 2020, the Commonwealth Government amended the Regulations to make the DMO price cap apply to residential customers on TOU and solar tariffs, and to small business customers on solar tariffs. This means the DMO annual price and model annual usage we determine for each distribution region will now apply to standing offer customers on these tariff types.[86]

The Regulations do not enable us to determine separate DMO prices or model annual usage for these tariff types.

This chapter sets out our methodology for determining the DMO model annual usage for 2020-21, including our approach to TOU and solar tariff customers.

Draft Determination

Annual usage

Our Draft Determination was to continue to use the annual usage amounts from our DMO 1 Determination for residential customers (with and without CL) and small business customers. Following the amendments to the Regulations, the residential usage amounts would apply to customers on TOU tariffs, as well as solar tariffs. The small business usage amount would apply to small business customers on solar tariffs.[87]

In the Draft Determination we noted available evidence indicated:

- the annual usage of TOU customers was broadly similar to non-TOU customers
- the annual usage of solar and non-solar customers was broadly similar.[88]

We therefore considered the annual usage for flat rate customers (that is, our DMO 1 annual usage determination) met the criteria of being 'broadly representative' of a TOU and solar customer for the purposes of the DMO 2 model annual usage determination.

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

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

87 AER, *Draft Determination, Default market offer prices 2020-21*, 10 February 2020, p. 49.

88 AER *Draft Determination, Default market offer prices 2020-21*, 10 February 2020, p. 51.

TOU customers

Timing and pattern of supply – daily usage profile

Our Draft Determination set a daily usage profile specifying the amount of energy a residential customer would use during each hour of the day over a 24 hour period, for each distribution region. We determined the profiles by converting the DMO 1 annual usage allocations into daily and hourly blocks.

This approach would enable retailers to determine when their peak, off-peak and shoulder usage periods apply and their prices for these tariff windows. Using the daily usage profile retailers could calculate the annual TOU price.

DMO annual price

The Regulations do not provide for us to make a separate annual price or model annual usage determination for TOU customers. Our Draft Determination therefore considered how we should take into account any differences in costs to serve TOU customers in the single DMO price.

Our Draft Determination position was that, while acknowledging retailers faced higher fixed costs to serve TOU customers in some regions, we would not adjust the DMO price to account for these. This was because:

- the DMO price is sufficient to enable recovery of efficient costs for TOU customers, being above the median TOU market offer, our proxy for a retailer's efficient costs.
- the relatively small number of customers on TOU standing offer tariffs would mean any cost differences, where they exist, would have limited impact on retailers' revenues
- our proposed daily usage profiles addressed the possibility of higher network usage costs as retailers could now determine a level of peak, off-peak and shoulder time periods relevant to their retail tariff. Our analysis showed TOU network usage costs under our proposed daily usage profiles (aligned to network tariffs) were similar to or lower than flat rate network usage costs.

Solar customers – timing and pattern of supply and annual price

Our Draft Determination acknowledged that while retailers incur some moderate additional costs to serve solar customers, the DMO price was sufficient in each region to accommodate any differences in costs without affecting retailers' abilities to recover efficient costs. Our draft position was not to adjust the DMO price to take higher costs into account.

Stakeholder submissions

Annual usage

Stakeholders generally supported our Draft Determination approach of using the DMO 1 annual usage amounts, noting they provide simplicity, consistency and comparability.[89]

Powershop/Meridian sought further detail on how we determined average small business customer usage.[90]

The figure of 20,000 kWh was reported by the ECA and we consider it the best available approximation for our purpose.[91]

TOU customers

Daily usage profile

Stakeholders generally supported our Draft Determination approach to TOU tariffs:

- EnergyAustralia considered the hourly usage profiles provided for a more accurate comparison between actual tariff prices and the reference price[92]
- Derek Bolton considered an daily usage profile was preferable to fixed peak, off-peak and shoulder allocations[93]
- QCOSS (Etrog Consulting) welcomed the implementation of an hourly usage profile in preference to fixed tariff windows[94]
- Alinta Energy similarly supported the introduction of a daily usage profile in preference to fixed tariff windows, noting that though calculations to compare tariffs with the DMO price involve some additional steps, the flexibility it affords retailers is likely to better meet the DMO objectives.[95]

Some stakeholders also suggested minor changes to clarify how the profiles work, and improve their accuracy.

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89 AER, *Draft determination default market offer prices 2020-21*, p. 52.

90 Powershop/Meridian, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

91 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.

92 EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 9.

93 Derek Bolton, *Submission to DMO 2 Draft Determination,* 20 February 2020, p. 1.

94 Etrog consulting (on behalf of Queensland Council of Social Service Inc), *Submission to DMO 2 Draft Determination,* 9 March 2020, p. 21.

95 Alinta Energy, *Submission to DMO 2 Draft Determination,* 9 March 2020, p. 2.

To improve accuracy, EnergyAustralia suggested we develop TOU usage profiles distinguishing weekday and weekend use, and that we specify the hourly profile blocks to four decimal points to ensure they add to a whole number.[96]

We acknowledge that while weekend electricity usage patterns are likely to differ from weekday usage, we do not currently have detailed usage data that would enable us to reflect this difference in the profiles. We may consider stakeholders' preferences for more detailed profiles in future DMO consultations, where access to customer usage data may be possible using our information gathering powers.

We agree it is preferable for the daily usage to add as closely as possible to the whole annual usage figure and have adjusted the profiles accordingly.

EnergyAustralia and QCOSS (Etrog Consulting) suggested we clarify how retailers were to use the profiles, including providing worked examples.[97]

We note the ACCC provides guidance to retailers about their responsibilities under the Code through its *Guide to the Electricity Retail Code*, which includes illustrative examples for the DMO price cap and reference price provisions. The ACCC will be updating this document to take into account the recent revisions to the Regulations, and the new daily profile approach TOU usage.

Powershop/Meridian and the AEC requested we continue to monitor differences in costs to serve between TOU customers and flat rate customers to ensure our assumptions remain appropriate in future determinations.[98]

Alinta Energy encouraged the AER to continue to consider the impacts of tariff reform on the DMO in future determinations.[99]

While recognising that tariff reform encompasses more than TOU tariffs, we will continue to monitor the implementation of TOU tariffs as part of future DMO determinations. We are also mindful of the interaction between the DMO and tariff reform in our role in assessing network businesses' tariff proposals.

Derek Bolton suggested the daily usage profile could be manipulated by retailers to increase revenues from some customer segments.[100] He suggested that where the usage profile does not align with actual customer usage for individual users, retailers have an opportunity to increase earnings above the estimated annual DMO limit. In particular, he suggested the usage profile does not align with the actual peak periods experienced by some users, and underestimates peak usage. He suggested retailers

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[96] EnergyAustralia, *Submission to DMO 2 Draft Determination*, 13 March 2020, p. 9.

[97] Etrog consulting (on behalf of Queensland Council of Social Service Inc), *Submission to DMO 2 Draft Determination,* 9 March 2020, p. 15.

[98] Powershop/Meridian, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 3; Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2.

[99] Alinta Energy, *Submission to DMO 2 Draft Determination,* 9 March 2020, p. 2.

[100] Derek Bolton, *Submission to DMO 2 Draft Determination,* 20 February 2020, p. 1.

will specify higher tariffs for actual peak periods, enabling them to increase earnings above the estimated annual DMO limit.

We acknowledge the profiles are highly simplified. Their purpose is to give retailers a more flexible way to calculate annual usage in each TOU period. It is this annual usage figure that a retailer must apply when setting prices, such that the combined annual price of the peak, shoulder and off-peak periods do not exceed the DMO price.

Currently, retailers are free setting their TOU prices in way that maximises the profitability of customers with particular usage profiles. In our view, the requirement that retailers use our daily usage profiles when setting standing offer prices does not significantly alter this status quo. Providing flexibility to retailers to set tariff windows and prices also enables them to pass on network price signals to customers seeking to relieve network congestion during peak periods, consistent with network tariff reform.

Advanced meters

Some stakeholders suggested the DMO price should reflect the higher costs retailers incur for installing and maintaining advanced ('digital' or 'smart') meters, noting the Power of Choice reforms require these be installed where conventional accumulation meters require replacement, and a range of other situations.

Metering coordinator, Vector, noted increasing installation costs due to recently introduced rules requiring retailers to install meters within set timeframes. It also noted retailers incurred additional costs to remediate unsafe sites so that meters could be installed safely. These costs would become more material for retailers as more consumers switched to advanced meters.[101]

1st Energy suggested the replacement of accumulation with advanced meters costs of $140 per customer per annum.[102]

Vector and 1st Energy considered we should increase the DMO price to take into account these costs.[103]

The AEC also highlighted the move to cost reflective tariffs and noted it may be necessary for the AER to take into account the annual cost of advanced meters in future DMO determinations.[104]

As noted, there is no provision under the Regulations for us to determine a separate DMO price for TOU customers. Accordingly, we have considered how any additional costs for advanced meters should be accounted for in the single DMO price. We also

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101 Vector, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

102 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

103 Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2; Vector, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 3; 1st Energy, *Submission to DMO 2 Draft Determination*, 9 March 2020, p. 2.

104 Australian Energy Council (AEC), *Submission to DMO 2 Draft Determination,* 10 March 2020, p. 2.

note, in setting the DMO price the Regulations require us only to consider annual or ongoing costs, not one-off fees or a fee for a service provided on request.[105]

Under the Power of Choice reforms, advanced meter costs are not regulated and form part of the contract between retailers and metering coordinators. We have no visibility over these commercial arrangements. In the absence of detailed cost information, we have considered analysis conducted by the Queensland Competition Authority in 2019, and the accompanying consultant's report from ACIL Allen.[106]

Key findings from these reports are:

- the average annual cost of an advanced meter is higher than a conventional meter. Based on ACIL Allen's research, the QCA final report found a typical residential advanced meter costs approximately $118 per meter per annum in South East Queensland, though actual costs vary by retailer.[107] They suggested an accumulation meter costs around $36 per year
- retailers recover the costs of advanced meters in different ways. QCA noted most retailers do not currently charge customers individually for their particular metering costs. Due to the relatively small number of advanced meters installed, retailers either absorb the costs, or spread them across all customers[108]
- retailers avoid some costs when a customer has a smart meter installed. These include meter reading costs (as advanced meters can be read remotely) and the costs that would have been incurred had an accumulation meter been installed.

In assessing whether the single DMO annual price meets the DMO policy objectives in regards to customers with advanced meters, we have considered whether the DMO cap enables retailers to recover their efficient costs.

Our analysis of October 2019 TOU market offer prices in our Draft Determination indicates there is a significant margin between the median market offer (our proxy for retailers' efficient costs) and the DMO price.[109]

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105 Regulations, s. 5 (see the definition of 'price').

106 QCA, *Ministerial advice: Benefits of advanced digital metering,* September 2019; ACIL Allen, *Report to the Queensland Competition Authority, Advanced digital meters, estimating the potential net benefits final report,* 2 September 2019.

107 QCA, *Ministerial advice: Benefits of advanced digital metering,* September 2019, p. 3; ACIL Allen, *Report to the Queensland Competition Authority, Advanced digital meters, estimating the potential net benefits final report,* 2 September 2019, p. 16.

108 QCA, *Ministerial advice: Benefits of advanced digital metering,* September 2019, p. 3; ACIL Allen, *Report to the Queensland Competition Authority, Advanced digital meters, estimating the potential net benefits final report,* 2 September 2019, p. 28.

109 AER, *Draft determination default market offer prices 2020-21,* p. 59.

Table 8 shows the median TOU market offer bill (where annual usage aligned to the underlying TOU network tariff windows) is below the median flat rate market offer and the DMO 1 price.

Table 8: Median annual market offer price, flat rate and TOU[110]

	Median bill – TOU (network tariff-aligned profile)	DMO 1 price	$ margin (median bill below the DMO price)
Ausgrid	$1,252	$1,467	$215
Endeavour	$1,395	$1,720	$325
Essential	$1,672	$1,957	$285
Energex	$1,396	$1,570	$174
SAPN *	N/A	$1,941	N/A

Note: * There are no TOU offers in the SAPN region from which to calculate median bills.

While we acknowledge advanced meters and associated costs will be higher than for accumulation meters, based on the above analysis and the QCA cost information, we are satisfied the DMO price is at a high enough level above retailers' efficient costs to enable retailers to recover the recurring costs of advanced meters. Our Final Determination position is not to make any adjustment to the DMO price to account for advanced metering costs.

We note comments from the AEC, Vector and 1st Energy suggesting the increasing uptake of advanced meters means the associated costs will become increasingly significant for retailers, and the suggestion that we continue to monitor this. We acknowledge the Power of Choice reforms will result in a growing proportion of advanced meters in the future. We will continue to monitor our approach to ensure it remains appropriate in future DMO Determinations.

Solar customers

Most submissions to the Draft Determination did not comment on our proposed approach to extending the DMO price cap to solar customers. We note stakeholders previously expressed support for the approach first set out in our Position Paper.

110 TOU annual bills have been calculated using the affordability reporting function from Energy Made Easy, and are indicative only.

Final Determination

Annual usage

Our Final 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.

The residential annual usage amount (with and without CL) will apply to customers with solar and TOU tariffs.

The small business annual usage amount will apply to customers on solar tariffs.

The annual usage amounts are set out in Table 9.

Table 9: 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

Timing and pattern of supply

Consistent with our Draft Determination, our Final Determination on the timing and pattern of supply is to:

- assume the same usage pattern occurs every day of the year (with no seasonal differences)
- continue to use the allocations of total annual CL usage across multiple CLs from our DMO 1 determination
- set a daily usage profile for TOU customers, specifying the amount of energy a customer would use during each hour of the day over a 24 hour period for each distribution region

The daily usage profiles for each distribution region and the allocations for multiple CLs are specified in the DMO Legislative Instrument included at **Appendix F**.

Appendices

Appendix A – List of submitters to AER Draft Determination and on the COVID-19 implications for the DMO

Appendix B – Market offer analysis for each distribution region

Appendix C – List of annual bill calculation assumptions

Appendix D – Forecast changes in cost components

Appendix E – Matters we have had regard to in determining DMO prices

Appendix F – Legislative instrument

Appendix G – Statement of compatibility with human rights

Appendix H – Nominal price movements from Draft Determination to Final Determination

A List of submitters to AER Draft Determination and on the COVID-19 implications for DMO

Draft Determination submissions

1. 1st Energy
2. Australian Energy Council (AEC)
3. AGL
4. Alinta Energy
5. Energy Consumers Australia (ECA)
6. EnergyAustralia
7. Derek Bolton
8. Origin Energy
9. Powershop/Meridian
10. Public Interest Advocacy Centre (PIAC)
11. Queensland Council of Social Service Inc (QCOSS), Etrog Consulting
12. Red Energy/Lumo (confidential)
13. Vector

Submissions on the COVID-19 consultation

1. 1st Energy
2. ACT Civil and Administrative Tribunal (ACAT)
3. Australian Energy Council (AEC)
4. AGL (public and confidential)
5. Amaysim
6. AER Consumer Consultative Group members
7. Energy Consumers Australia (ECA)
8. EnergyAustralia (confidential)
9. ERM Power
10. Ion Group (QEnergy, Mojo Power, People Energy, Sanctuary Energy)
11. Locality Planning Energy (LPE)
12. Momentum Energy
13. NECTR

14. Public Interest Advocacy Centre (PIAC)
15. Origin Energy (confidential)
16. Powershop/Meridian
17. Queensland Energy Users Network (QEUN)
18. Quinbrook (Cape Byron Power, Energy Trade, Energy Locals)
19. Simply Energy (public and confidential)
20. Red Energy/Lumo (confidential)
21. Vector
22. Vocus

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*.[111] 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 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 regions. For small business customers, the annual usage is 20,000 kWh.

B.1 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 four points in time:

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

- 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
- 31 December 2019 – six months after the introduction of the DMO
- 31 March 2020 – nine months after the introduction of the DMO.

Figures B.1 to B.15 show these movements in graph form. These 15 charts show the offers from Energy Made Easy (EME) for residential flat rate customer offers, residential flat rate customers with controlled load and small business flat rate customers.

Changes in market offer prices in Ausgrid's region

Figure B1: Residential flat rate tariff

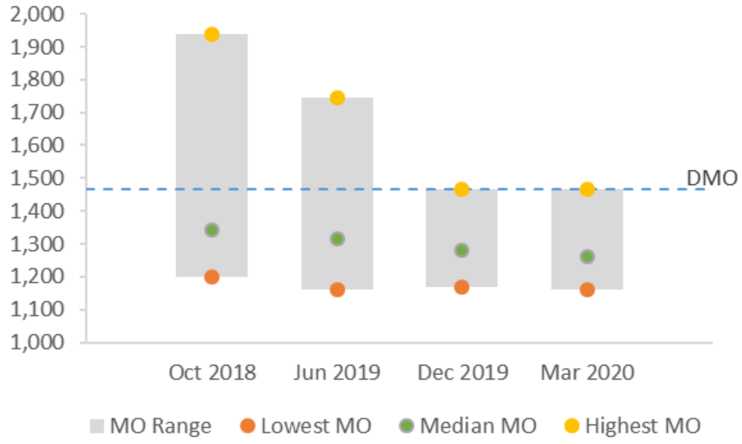


Figure B2: Residential flat rate tariff with controlled load

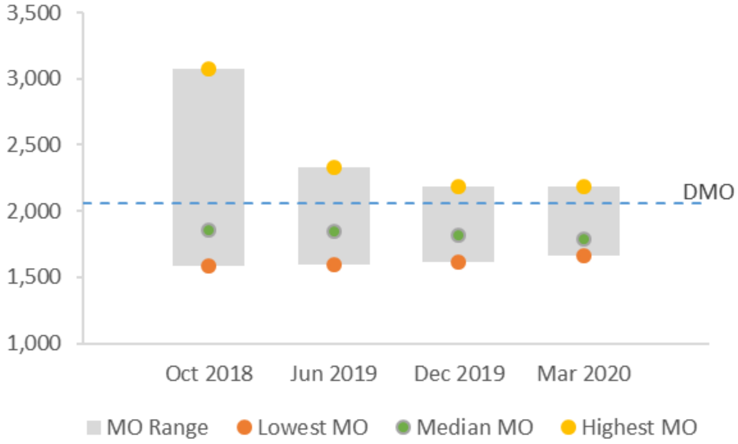
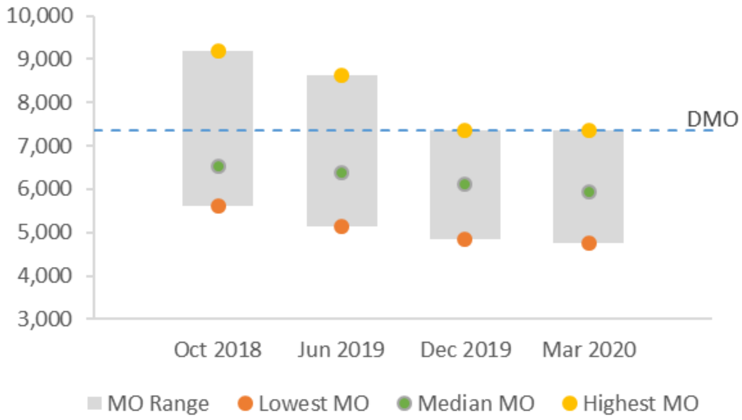


Figure B3: Small business flat rate tariff



Changes in market offer prices in Endeavour Energy's region

Figure B4: Residential flat rate tariff

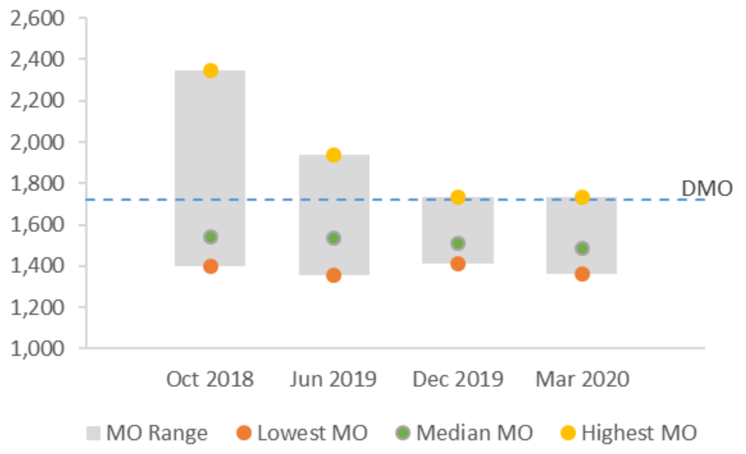


Figure B5: Residential flat rate tariff with controlled load

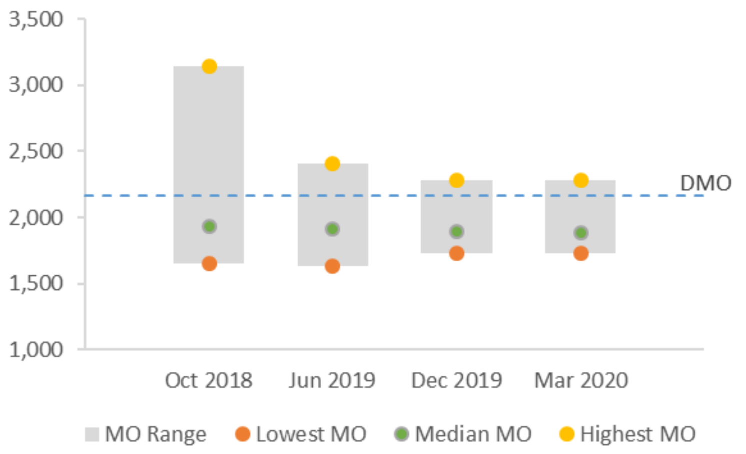
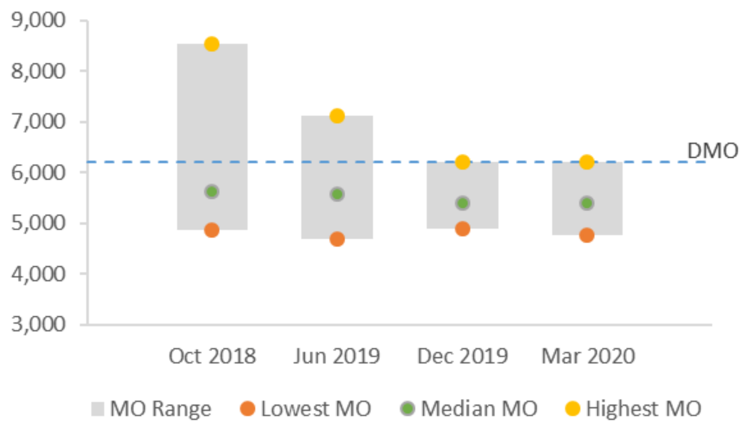


Figure B6: Small business flat rate tariff



Changes in market offer prices in Essential Energy's region

Figure B7: Residential flat rate tariff

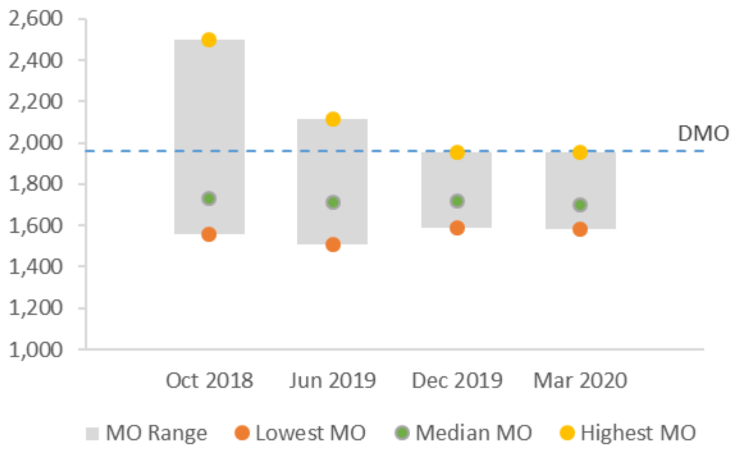


Figure B8: Residential flat rate tariff with controlled load

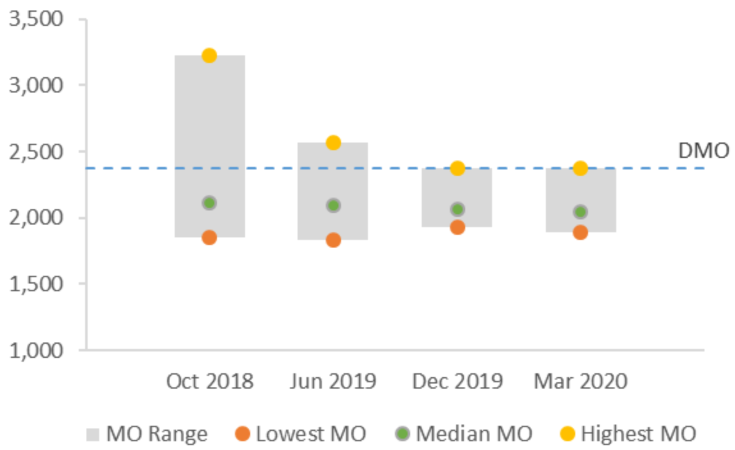
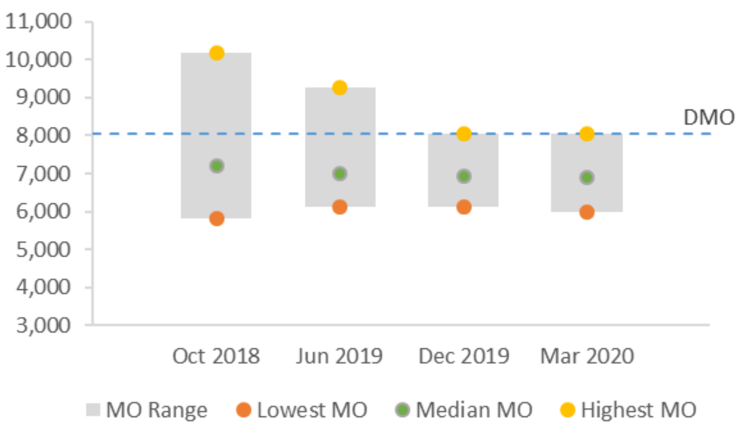


Figure B9: Small business flat rate tariff



Changes in market offer prices in Energex's region

Figure B10: Residential flat rate tariff

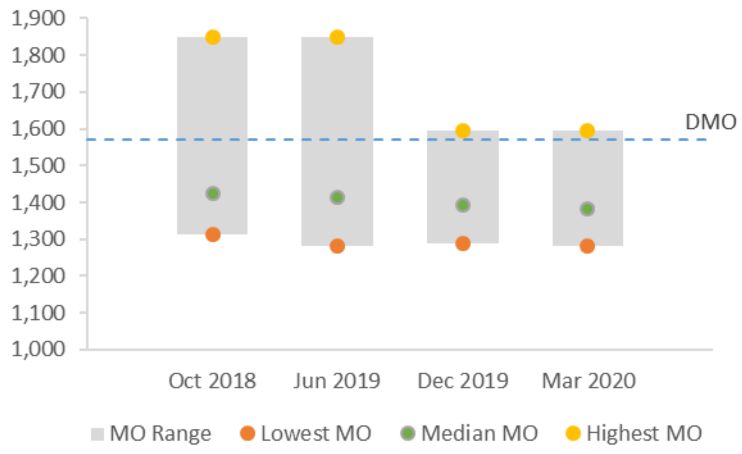


Figure B11: Residential flat rate tariff with controlled load

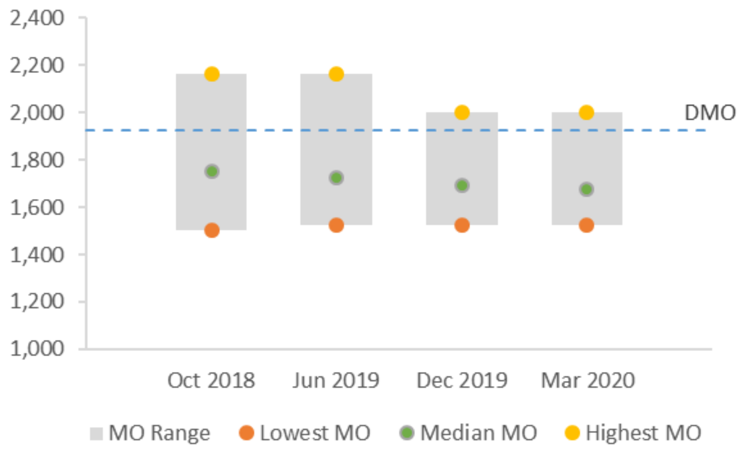
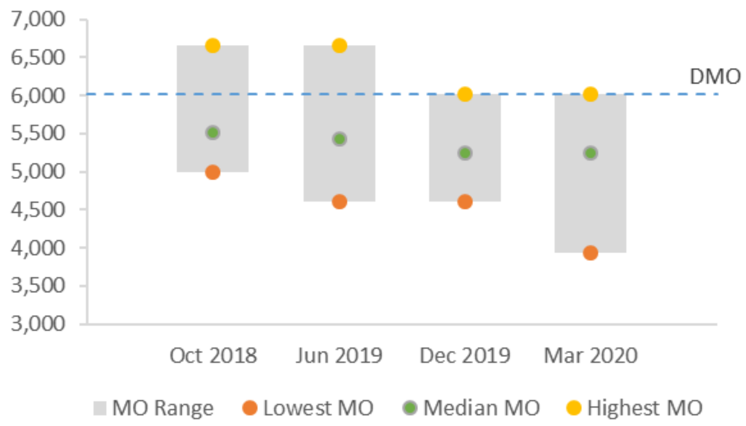


Figure B12: Small business flat rate tariff



Changes in market offer prices in SAPN's region

Figure B13: Residential flat rate tariff

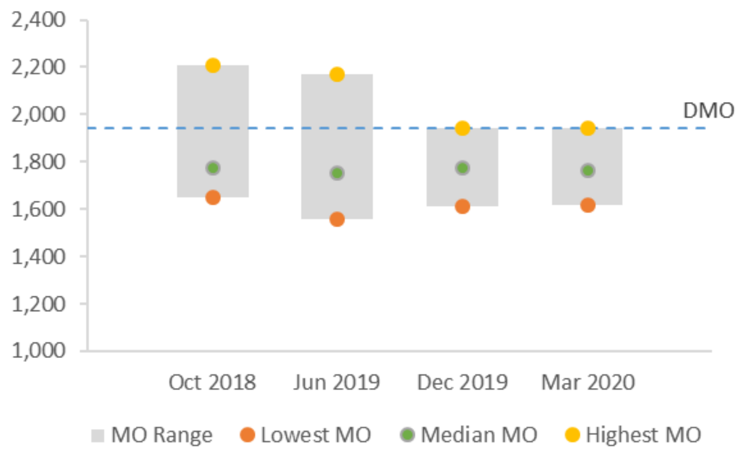


Figure B14: Residential flat rate tariff with controlled load

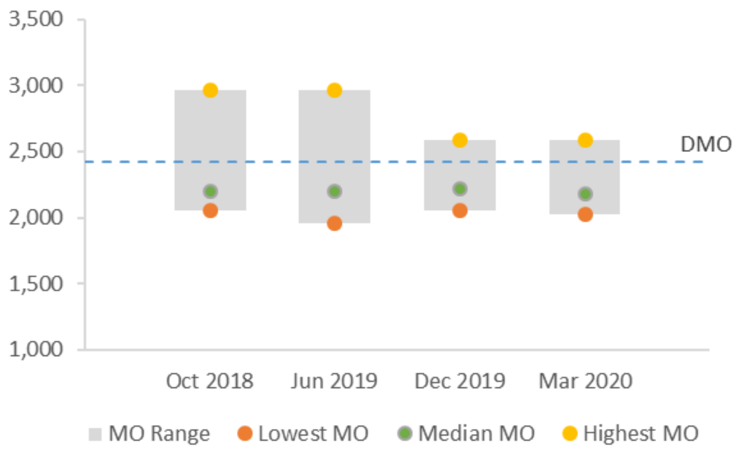
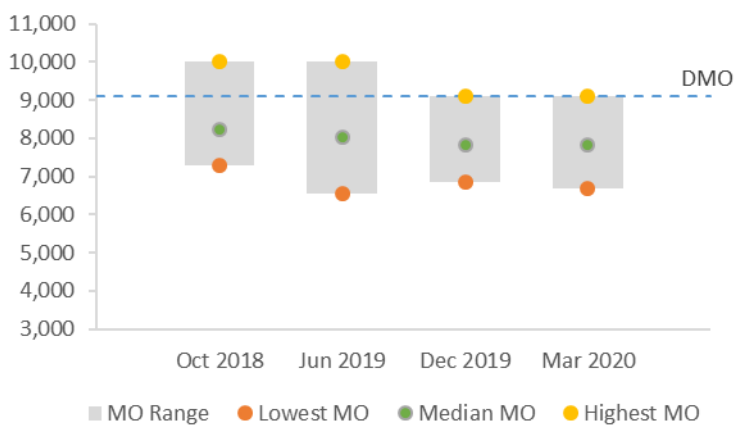


Figure B15: Small business flat rate tariff



From October 2018 to December 2019, the change in median market offers across the distribution regions for residential customers ranged from a reduction of 4.5 per cent to a marginal increase of 0.5 per cent. From December 2019 to March 2020, the median market offer for both residential flat rate and flat rate with controlled load tariffs decreased in all regions between 1 to 2 per cent.

The lowest market offer for small businesses decreased in all regions from December 2019 to March 2020, ranging from 2 to 3 per cent in all regions, with the exception of the Energex region, which had a 15 per cent reduction in the lowest market offer. The vast majority of market offers continue to be below or equal to the DMO, ranging between 95 to 100 per cent of offers, depending on the region and tariff type. There are no tariff restrictions on market offers – for the set usage the bill may be more than the applicable DMO. This could be because they have an innovative offer (includes new technology or features) or may be targeted at higher or lower consumption customers (higher or lower daily charge with an opposite change in usage component).

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 note that from 1 July 2019, network prices increased in some regions (Essential and SAPN) but reduced or remained flat in all other regions. 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. In March 2020 only 11 to 17 per cent of market offers featured conditional discounts depending on the region and tariff type. This is a large reduction compared with market offers available in June 2019, where 32 to 62 per cent featured conditional discounts. We will continue to monitor these changes over the longer term.

C 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).

D 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

D.1 Annual usage

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

D.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 D1: 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 N90
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

Distribution region	Residential flat rate	Residential CL	Small business flat rate
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 3.3.3, for the determination year 2020-21, the network tariffs for the Essential region in this Final Determination were sourced from the Tariff structure statements (TSS) in the 2020-21 annual pricing proposal submitted by the distribution network business. For Ausgrid and Endeavour regions, the 2020-21 annual pricing proposals received from the businesses had incorporated changes in forecast demand that the AER was still assessing at the time of the finalising this Final Determination. Therefore, for Ausgrid and Endeavour regions the network tariffs were sourced from the indicative 2020-21 tariffs in the 2019-20 annual pricing proposals approved by the AER.[112] For Energex and SAPN, we have used the indicative tariffs available in the revised pricing proposal for the network revenue determination 2020-2025.[113]

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, Queensland Solar Bonus Scheme (SBS) in South East Queensland and Essential region, 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.

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)

112 Pricing proposals and tariffs 2019-20 are available on the AER website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs

113 Determination and access arrangements are available on the AER website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?f%5B0%5D=type%3Aaccc_aer_determination

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 Final 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 3.3.3, the approved network tariffs are not be available for the regions undergoing a revenue reset in 2020 – Energex and SAPN. Therefore, we have used the indicative tariffs from the revised regulatory proposals to assess changes in network costs in the reset regions, as these reflect the likely tariff structures and include other cost information.

D.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, the Draft Determination 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, and prudential costs. The environmental costs include the costs associated with Large-scale Renewable Energy Target (LRET), Small-scale Renewable Energy Scheme (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 wholesale or environmental cost 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)

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 cost estimates from the Consultant for the single CLP to both controlled load tariffs in these two distribution regions.

D.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 above, the residual component was then adjusted for consumer price index (CPI) inflation sourced from the Reserve Bank of Australia (RBA) estimates.[114]

D.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 CPI) +

Step change, if any

[114] The CPI inflation applied to the DMO 2 time period is published in the RBA's output growth and inflation forecasts for year-ended June 2021, from the RBA's February 2020 Statement of Monetary Policy.- Economic Outlook

E Matters we have had regard to in determining DMO prices

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 we received throughout our consultation process.

Table E1 summarises how we have considered each of the matters under section 16(4) in determining total annual prices.

Table E1: 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 region, 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 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.[115] • 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.

115 See discussion in section 3.3.

	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 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.[116]

[116] ACCC, *Submission to the AER Position Paper*, p. 2.

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)	**0.3395**	**0.3395**	**0.3395**	**0.3395**	**0.3395**	**0.3395**	**0.3395**	**0.4690**	**0.4690**	**0.4690**	**0.4690**	**0.4690**	**0.4690**	**0.4690**	**0.5681**	**0.5681**	**0.5681**	**0.5681**	**0.5681**	**0.5681**	**0.4690**	**0.4690**	**0.3395**	**0.3395**

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)	**0.4179**	**0.4179**	**0.4179**	**0.4179**	**0.4179**	**0.4179**	**0.4179**	**0.5772**	**0.5772**	**0.5772**	**0.5772**	**0.5772**	**0.5772**	**0.5772**	**0.6992**	**0.6992**	**0.6992**	**0.6992**	**0.6992**	**0.6992**	**0.5772**	**0.5772**	**0.4179**	**0.4179**

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
Usage (kWh/hour)	**0.4072**	**0.4072**	**0.4072**	**0.4072**	**0.4072**	**0.4072**	**0.4072**	**0.5832**	**0.5832**	**0.5832**	**0.5832**	**0.5832**

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)	**0.5832**	**0.5832**	**0.7518**	**0.7518**	**0.7518**	**0.7518**	**0.7518**	**0.7518**	**0.5832**	**0.5832**	**0.4072**	**0.4072**

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
Usage (kWh/hour)	**0.4321**	**0.4321**	**0.4321**	**0.4321**	**0.4321**	**0.4321**	**0.4321**	**0.6189**	**0.6189**	**0.6189**	**0.6189**	**0.6189**

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)	**0.6189**	**0.6189**	**0.7978**	**0.7978**	**0.7978**	**0.7978**	**0.7978**	**0.7978**	**0.6189**	**0.6189**	**0.4321**	**0.4321**

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
Usage (kWh/hour)	**0.3725**	**0.3725**	**0.3725**	**0.3725**	**0.3725**	**0.3725**	**0.3725**	**0.5503**	**0.5503**	**0.5503**	**0.5503**	**0.5503**

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)	**0.5503**	**0.5503**	**0.7163**	**0.7163**	**0.7163**	**0.7163**	**0.7163**	**0.7163**	**0.5503**	**0.5503**	**0.3725**	**0.3725**

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
Usage (kWh/hour)	**0.3563**	**0.3563**	**0.3563**	**0.3563**	**0.3563**	**0.3563**	**0.3563**	**0.5264**	**0.5264**	**0.5264**	**0.5264**	**0.5264**

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)	**0.5264**	**0.5264**	**0.6851**	**0.6851**	**0.6851**	**0.6851**	**0.6851**	**0.6851**	**0.5264**	**0.5264**	**0.3563**	**0.3563**

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)	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.7100**	**0.7100**	**0.7100**	**0.7100**	**0.7100**	**0.7100**	**0.5433**	**0.5433**	**0.3837**	**0.3837**

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)	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.3837**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.5433**	**0.7100**	**0.7100**	**0.7100**	**0.7100**	**0.7100**	**0.7100**	**0.5433**	**0.5433**	**0.3837**	**0.3837**

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)	**0.3641**	**0.3641**	**0.3641**	**0.3641**	**0.3641**	**0.3641**	**0.3641**	**0.4725**	**0.4725**	**0.4725**	**0.4725**	**0.4725**	**0.4725**	**0.4725**	**0.5717**	**0.5717**	**0.5717**	**0.5717**	**0.5717**	**0.5717**	**0.4725**	**0.4725**	**0.3641**	**0.3641**

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)	**0.3823**	**0.3823**	**0.3823**	**0.3823**	**0.3823**	**0.3823**	**0.3823**	**0.4961**	**0.4961**	**0.4961**	**0.4961**	**0.4961**	**0.4961**	**0.4961**	**0.6003**	**0.6003**	**0.6003**	**0.6003**	**0.6003**	**0.6003**	**0.4961**	**0.4961**	**0.3823**	**0.3823**

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	N/A	N/A

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	$1,462	$2,024	$7,240
Endeavour Energy	$1,711	$2,165	$6,177
Energex	$1,508	$1,812	$5,760
Essential Energy	$1,960	$2,356	$8,041
SA Power Networks	$1,832	$2,244	$8,305

DATED THIS 30TH DAY OF APRIL 2020

Australian Energy Regulator

G Statement of compatibility with human rights

This Legislative Instrument has been prepared in accordance with the human rights and freedoms recognised or declared in the international instruments listed in section 3 of the *Human Rights (Parliamentary Scrutiny) Act 2011*: see Appendix A.

Appendix A

STATEMENT OF COMPATIBILITY WITH HUMAN RIGHTS

Prepared in accordance with Part 3 of the Human Rights (Parliamentary Scrutiny) Act 2011

Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2019

The Determination is compatible with the human rights and freedom recognised or declared in the international instruments listed in section 3 of the *Human Rights (Parliamentary Scrutiny) Act 2011*.

Overview of legislative instrument

This Legislative Instrument sets out the AER's determinations under Part 3 of the *Competition and Consumer (Industry Code – Electricity Retail Regulations 2019* (the Regulations). Specifically:

- Clause 5 sets out the AER determined per-customer amount of electricity supplied in specified distribution regions to small customers.
- Clause 6 sets out the AER determined timing or pattern of the supply of electricity in specified distribution regions to small customers.
- Clause 7 sets out the AER determined reasonable per-customer annual price for supplying electricity in specified distribution regions to small customers.

The determinations made by the AER under the Legislative Instrument commence on 1 July 2020.

The Regulations confer price setting functions on the AER.

Human rights implications

The Legislative Instrument is prepared under the Regulations. The Regulations regulate business conduct and do not engage any of the applicable rights or freedoms.

Conclusion

The Legislative Instrument is compatible with human rights as it does not raise any human rights issues.

H Nominal price movements from Draft Determination to Final Determination

Table H1 shows the nominal movement for each cost component between the DMO 2 Draft Determination published on 10 February 2020 and this Final Determination.

Table H1: Changes in cost components from DMO 2 Draft to Final Determination ($nominal)

Description	DMO 2 Draft 2020-21	Network cost	Wholesale cost	Environ-mental cost	Residual cost	Overall nominal change	DMO 2 Final 2020-21
Residential without CL							
Ausgrid	**$1,483**	*$0*	*-$10*	*$0*	*-$11*	*-$21*	**$1,462**
Endeavour	**$1,729**	*$0*	*-$6*	*$1*	*-$13*	*-$18*	**$1,711**
Essential	**$1,967**	*$15*	*-$9*	*$0*	*-$13*	*-$7*	**$1,960**
Energex	**$1,484**	*$51*	*-$13*	*-$1*	*-$13*	*$24*	**$1,508**
SAPN	**$1,856**	*$0*	*-$13*	*-$0*	*-$11*	*-$24*	**$1,832**
Residential with CL							
Ausgrid	**$2,059**	*$0*	*-$16*	*$0*	*-$18*	*-$35*	**$2,024**
Endeavour	**$2,193**	*$0*	*-$10*	*$1*	*-$20*	*-$28*	**$2,165**
Essential	**$2,383**	*$4*	*-$14*	*$1*	*-$18*	*-$27*	**$2,356**
Energex	**$1,780**	*$65*	*-$15*	*-$1*	*-$17*	*$32*	**$1,812**
SAPN	**$2,282**	*$1*	*-$22*	*-$0*	*-$17*	*-$38*	**$2,244**
Small business without CL							
Ausgrid	**$7,348**	*$0*	*-$53*	*$0*	*-$55*	*-$108*	**$7,240**
Endeavour	**$6,250**	*$0*	*-$23*	*$4*	*-$54*	*-$73*	**$6,177**
Essential	**$8,081**	*$52*	*-$39*	*$2*	*-$55*	*-$40*	**$8,041**
Energex	**$5,647**	*$227*	*-$57*	*-$2*	*-$55*	*$113*	**$5,760**
SAPN	**$8,429**	*$0*	*-$66*	*-$1*	*-$57*	*-$124*	**$8,305**

Note: Due to rounding in this table, totals may not sum exactly.

The key drivers for these movements are:

- **Networks costs** used in the Draft Determination were maintained in all the distribution regions except Essential, with 2020-21 network prices still to be approved for those regions at the time of making this Final Determination. There was a slight change (of under $1) in charges in the Alternate Control Services (ACS) for some customers. The increase in the Energex region is as a result of the shift in solar bonus scheme funding arrangement from the Queensland Government to the network businesses. See section 3.3.3 for more detail.

- **Wholesale costs**, which includes wholesale energy and other market participation costs decreased across all regions. Wholesale energy costs have decreased by between $1.49 (QLD) and $3.82 per MWh (SA) due to lower observed forward contract prices. This reduction is offset in part by increase in ancillary services and prudential costs between $0.45 per MWh (SA) and $1.20 per MWh (NSW).

- **Environmental costs** remained steady, with minor upward revisions to the Small-scale Renewable Energy Scheme compliance costs resulting from Clean Energy Regulator's issuance of binding 2020 Small-scale Technology Percentage in March. Large-scale Generation Certificate forward prices remained subdued with an influx of renewable investments coming online over the next 18 months.

- **Residual costs** decreased as a result of RBA's revised CPI forecast for the 2020-21 period falling from 1.85% (November 2019 forecast) to 1.75% (February 2020 CPI forecast).