FINAL DETERMINATION

Default Market Offer Prices 2021-22

27 April 2021

AUSTRALIAN ENERGY REGULATOR

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Contents

Shortened forms

Shortened form	Extended form
5MS	5 minute settlement
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

Shortened form	Extended form
LGC	Large-scale Generation Certificate
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

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

1 Summary

1.1 The DMO price cap and its objectives

This is our Final Determination for retail electricity default market offer (DMO) prices to apply from 1 July 2021 to 30 June 2022.

The Default Market Offer (DMO) is the maximum price an electricity retailer can charge a standing offer customer each year. A customer might be on a standing offer if they have never switched to a retailer's market offer, or for a range of other reasons.

The objectives of the DMO price cap are to:

- prevent retailers charging unjustifiably high standing offer prices
- allow retailers to recover their efficient costs of providing services, including a reasonable retail margin
- ensure there are incentives for competition, innovation and investment by retailers, and retain incentives for consumers to engage in the market.

Our first DMO determination, for 2019-20 (DMO 1), resulted in annual reductions of $118 to $181 to the median standing offer price for residential customers.

For our 2020-21 determination (DMO 2), we maintained the balance we achieved in the initial DMO by:

- adjusting the environmental, wholesale and network components of the retail bill 'cost stack' to take into account the forecast changes for the 2020-21 period
- adjusting residual costs (including retail costs) in line with changes to the cost of inflation.

We referred to this as an indexation approach.

Compared to DMO 1, our DMO 2 determination saw prices:

- for residential customers reduce by a further $109 in the SAPN region, and $62 in the Energex region, while remaining flat in the New South Wales regions
- for business customers reduce by a further $815 in the SAPN region, $265 in the Energex region, and between $4 to $131 in the New South Wales regions.

1.2 Final DMO 2021-22 prices

Our continued use of the indexation approach has resulted in 2021-22 (DMO 3) prices that are lower for customers in all regions compared to last year. Compared to 2020-21, Final DMO 3 prices for residential customers without Controlled Load will be:

- $53-$102 lower in New South Wales (depending on the distribution region)
- $53 lower in South East Queensland
- $116 lower in South Australia.

For small business customers, DMO prices will be:

- $250-$441 lower in New South Wales (depending on distribution region)
- $243 lower in South East Queensland
- $272 lower in South Australia.

The main factors driving these decreases are:

- forecast wholesale cost reductions of 19 to 23 per cent compared to 2020-21, due to lower forward contract prices and the changing shape of load profiles due to continued strong investments in renewable generation. As wholesale costs account for around 27 to 41 per cent of the 2020-21 DMO price, these decreases have been the greatest driver of lower DMO 3 prices
- these decreases are offset in part by cost increases of 10 to 12 per cent for retailers to comply with government environmental regulations, including the Large-scale Renewable Energy Target and the Small-scale Renewable Energy Scheme, compared to last year. We call these environmental costs.

Network costs increased by around 1 to 14 per cent compared to 2020-21. Increases in all areas are larger than we predicted in the Draft Determination. In particular, higher transmission charges have been passed on through the network charges for customers in the Ausgrid, Endeavour and Essential Energy regions. Changes in demand since the pandemic have affected networks' revenue recovery, which has flowed into the following year's tariffs.

The AER had not approved network prices in time for use in the Final Determination. Consistent with our Draft Determination position, we have used the network businesses' 2021-22 network pricing proposals, submitted in March 2021. While there is the potential for these to change before being approved, this is the best information available to us at this time.

We have also applied the Reserve Bank of Australia's (RBA) February 2021 forecast Consumer Price Index inflation for the end of June 2022, of 1.5 per cent, to the DMO residual cost component.

We have not made any adjustments to the DMO price to reflect increases in retailers' operating costs under the step change framework. These include increases relating to COVID-19 bad and doubtful debt, advanced meters, and regulatory changes.

We have also clarified that our criteria for assessing step changes is whether the DMO policy objectives would be achieved if we did not make an adjustment.

In applying this test, we have conducted analysis that indicates that the DMO price remains well above the median market offer across the relevant DMO distribution regions. We have also 'stress tested' our analysis using a nominal $35 retailer cost increase figure (as an estimate of the cumulative impact of additional retailer costs) and have concluded that, even accounting for a $35 increase, the DMO price continues to meet the policy objectives.

Figures 1 and 2 illustrate the change in DMO price components between DMO 2 and DMO 3 for residential customers without Controlled Load (CL) and small business customers. Appendix D contains the full set of these figures for each customer type.

Figure 1: DMO 2 to DMO 3 cost component changes, residential flat rate

Figure 2: DMO 2 to DMO 3 cost component changes, small business

In addition to maintaining the reductions in standing offer prices we achieved in DMO 1 and DMO 2, these prices continue to balance the other DMO policy objectives.

- Our analysis (see section 3.3.4) indicates retailers can recover costs for serving customers, while also having incentives to compete on price and offer discounts.
- The significant margin between the DMO 3 prices and the lowest market offer prices in each area indicates there are strong financial incentives for DMO customers to shop around for a market deal.

1.3 DMO 3 approach

Having considered stakeholders' feedback, we have determined to adopt a largely unchanged approach to determining DMO 3 prices from our DMO 2 determination.

This remains the approach best suited to achieving the DMO policy objectives, while also providing consistency and stability for stakeholders.

Consideration of stakeholder feedback

Our Draft Determination, published in February 2021, set out our consideration of stakeholder views on a number key issues raised throughout the consultation. In summary we proposed:

- not to change key assumptions underpinning the wholesale forecasting methodology. This includes the time period over which our assumed retailer buys contracts to hedge its wholesale market risk, or our Consultant's use of the 95th percentile of modelled prices. Overall, retailer and consumer stakeholders did not support us changing these assumptions
- not to make an allowance for increased retailer costs due to the impact of the COVID-19 pandemic. We considered these were not significant enough to warrant an adjustment to the DMO price under our retail cost step change framework
- not to make an allowance for increased advanced meter costs, given current the low penetration of this technology
- not to make an allowance for costs relating to retailers' implementation of Consumer Data Right (CDR) and 5 minute settlement (5MS) regulatory changes. The limited information available suggested these costs would not be material enough to warrant adjusting the DMO price
- not to introduce a productivity adjustment into the DMO. Available information suggested that electricity retail productivity has not increased at a rate materially above the overall economy.

Stakeholders were generally supportive of our proposed approach to retain the same overall approach to setting the DMO price. However, most retailers raised concerns about our decision to not adjust the DMO price to account for various increases in their operating costs, including costs related to COVID-19 and advanced meters.

They considered these increases were material when taken together, and may erode the effectiveness of the DMO, reduce competition and act as a disincentive to innovation.

Some retailers also raised concerns about the transparency of our criteria for assessing costs under the DMO retail cost step change framework, noting we had not defined what constitutes ‘material costs’.

Consumer stakeholders, conversely, supported our decision not to take into account the retail cost increases. They noted the DMO price was deliberately set at a point well above the level where retailers could absorb such costs without impacting their ability to recover costs and make a reasonable margin.

We have had regard to these submissions in making this Final Determination, and set out our consideration of these issues in section 3.3.4.

1.4 DMO methodology review

We will undertake a review of our methodology for setting DMO prices as part of our DMO 2022-23 (DMO 4) determination, and any resulting changes to the methodology will therefore be implemented in the DMO 4 prices. As discussed in the Draft Determination, this will be important to ensure our approach remains appropriate to meeting the policy objectives.

Throughout this document, in discussing the reasons for our DMO 3 decision, we have flagged particular aspects of the methodology we may review for our DMO 4 determination. We intend to release a consultation paper setting out issues and options for consideration in our methodology review by August 2021.

The Department of Industry, Science, Environment and Resources (DISER) has also committed to a separate review of the DMO Regulations, which will commence in the second half of 2021. The DISER review will consider changes for the DMO Regulations.

We will work with DISER to align our respective reviews, and to coordinate the timing of key stages to minimise impact on stakeholders.

Any changes to the Regulations resulting from the DISER review will also be taken into account in our DMO 4 determination (See section 3.2.1).

Structure of our Final Determination

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

Chapter 3 explains our Final Determination for DMO prices

Chapter 4 explains our model annual usage determination, covering the annual usage amount and the timing and pattern of supply for TOU and solar customers, and costs to supply TOU customers

Appendix A – List of submitters to the DMO 3 Final Determination

Appendix B – Market offer analysis for each distribution region

Appendix C – Nominal price movements from the Draft Determination to Final Determination

Appendix D – DMO 2 to DMO 3 price movements

Appendix E – Legislative instrument

Appendix F – Statement of compatibility with human rights

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.

The *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2021* is the legislative instrument that formally sets out our Final Determination on default market offer price and usage determinations that will apply from 1 July 2021 to 30 June 2022 under the Regulations.

2.1 Policy context for the Default Market Offer

The DMO was introduced by the Commonwealth Government and commenced on 1 July 2019 following the recommendation by the ACCC's Retail Electricity Pricing Inquiry.[1] The purpose of the DMO was to cap the price of standing offers, which were previously used by retailers as a high priced benchmark from which their advertised market offers were derived, causing financial harm to consumers.[2] The AER was given the power to set the maximum price for the default offer in each jurisdiction; the legislative framework for determining DMO prices is contained in the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Regulations).[3]

The policy intent of the DMO, as set out by the ACCC in its recommendations, is to act as a fall-back option for those not engaged in the market, and should not be a low priced alternative to a market offer.[4] To achieve this it should:

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1 ACCC, Restoring electricity affordability and Australia's competitive advantage. Retail electricity pricing inquiry – final report, June 2018, p. v, xi–xii: https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_0.pdf

2 ACCC, R*estoring electricity affordability and Australia's competitive advantage. Retail electricity pricing inquiry – final report*, June 2018. See recommendations 30, 32, 49 and 50 and related discussion.

3 *Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019*: https://www.legislation.gov.au/Details/F2019L00530

4 ACCC, *AER Default market Offer, Submission to the Draft Determination*, 20 March, 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

- reduce unjustifiably high standing offer prices
- allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and customer acquisition and retention costs (CARC)
- not dis-incentivise competition, innovation and investment by retailers, and retain incentives for consumers to engage in the market.

We balanced these objectives in our DMO 1 determination by adopting a ‘top-down’ approach, based on retailers’ observed standing and market offer prices, rather than the cost-based ‘bottom-up’ approach conventionally applied in retail price regulation.

We set the DMO at a price where standing offer customers saw price reductions, but where retailers still have incentives to compete on price, invest and innovate with their market offers.

In each distribution region this was the mid-point (50th percentile) in the range between the median standing and median market offer.[5]

For our DMO 2 determination, we maintained this balance by adjusting retailers’ main costs (purchasing wholesale electricity, network, and costs to comply with government environment schemes) to reflect forecast changes. We applied CPI to the remaining retail cost ‘residual’. We referred to this approach as ‘indexation’.

Balancing the policy objectives has remained our primary consideration in determining DMO 3 prices.

2.2 Customers on standing offers

The majority of standing offer customers are customers of the ‘Tier One’ retailers ─ AGL, EnergyAustralia and Origin Energy.[6] The Tier One retailers are otherwise referred to as Local Area Retailers (LARs), who acquired the customer base of a particular region at the time of retail market privatisation.[7] 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)[8]

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5 AER, *Final Determination, Default market offer prices 2019-20,* April 2019, p. 30.

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

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

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

- have moved into a premises and receive supply from the existing retailer supplying the premises but are yet to make contact with the retailer[9]
- have defaulted to a standing offer following the expiry of a market contract.[10]

Table 1 sets out the number and proportions of standing offer customers for DMO areas in the second quarter of 2020-21.

Table 1: Standing offer customers in DMO areas

	Residential standing offer customers (Number and %)		Small business standing offer customers (Number and %)	
	Q1 2020-21	**Q2 2020-21**	**Q1 2020-21**	**Q2 2020-21**
New South Wales	379,840 (11.5%)	368,180 (11.1%)	73,620 (22.1%)	74,356 (22.2%)
South East Queensland Figures extrapolated from all Queensland by excluding Ergon customers. We note other retailers have customers in regional Queensland so figure is approximate	166,413 (11.6%)	175,453 (12.1%)	24,771 (22.5%)	26,053 (23.5%)
South Australia	63,834 (8%)	68,873 (8.7%)	13,662 (15.5%)	13,907 (15.8%)
Total standing offer customers	**610,087 (11%)**	**612,506 (11%)**	**112,053 (21.1%)**	**114,316 (21.4%)**

Source: AER Retail Market Performance update, Quarter 2 2020-21

We note that standing offer customer numbers have increased in the last quarter for all regions and customer types, except for New South Wales residential customers.

It is unclear whether any specific factor is driving the trend.

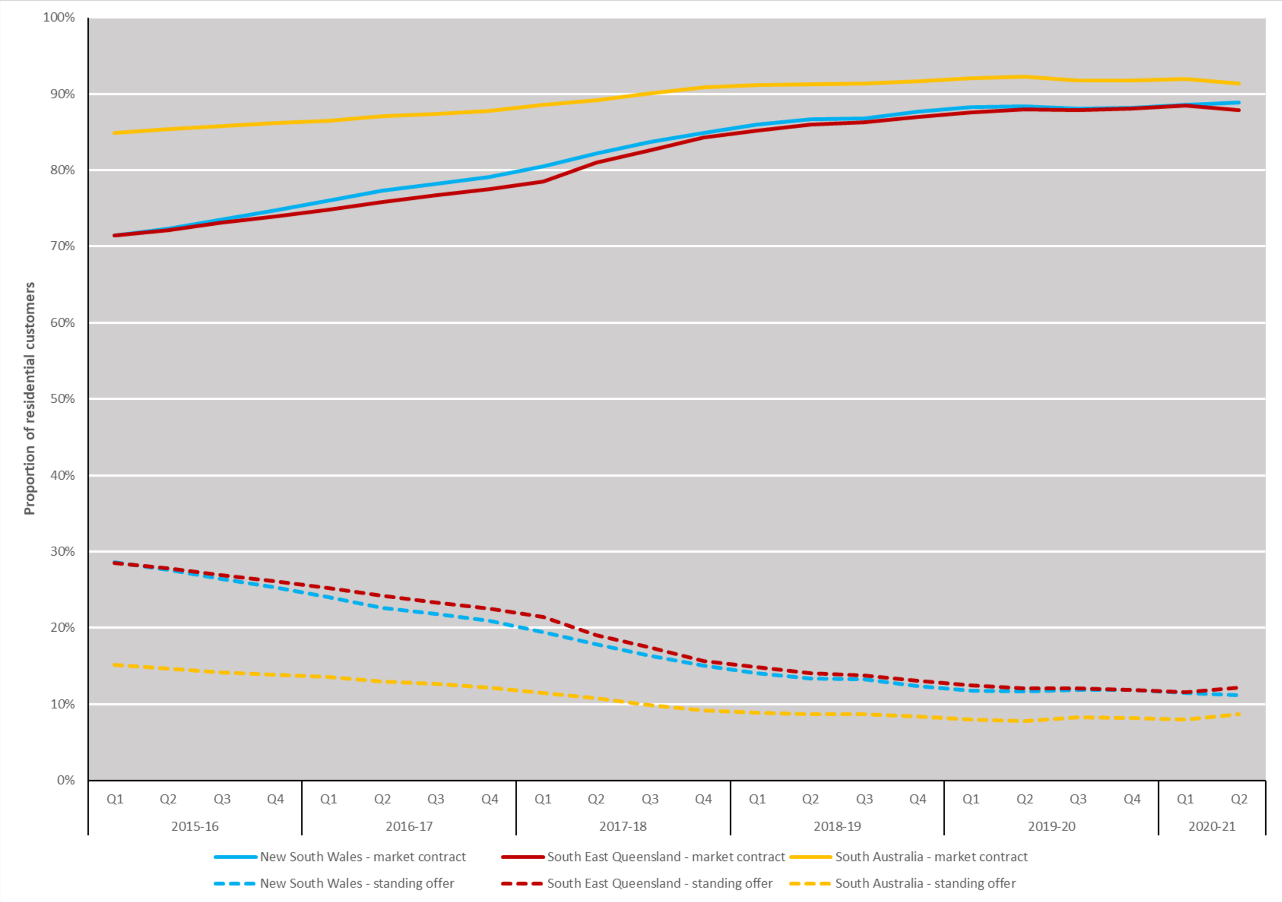
The long term trend (figures 3 and 4 below) show that the increase in standing offer customer numbers is marginal compared to the long-run trend of steady decline.

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

10 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.

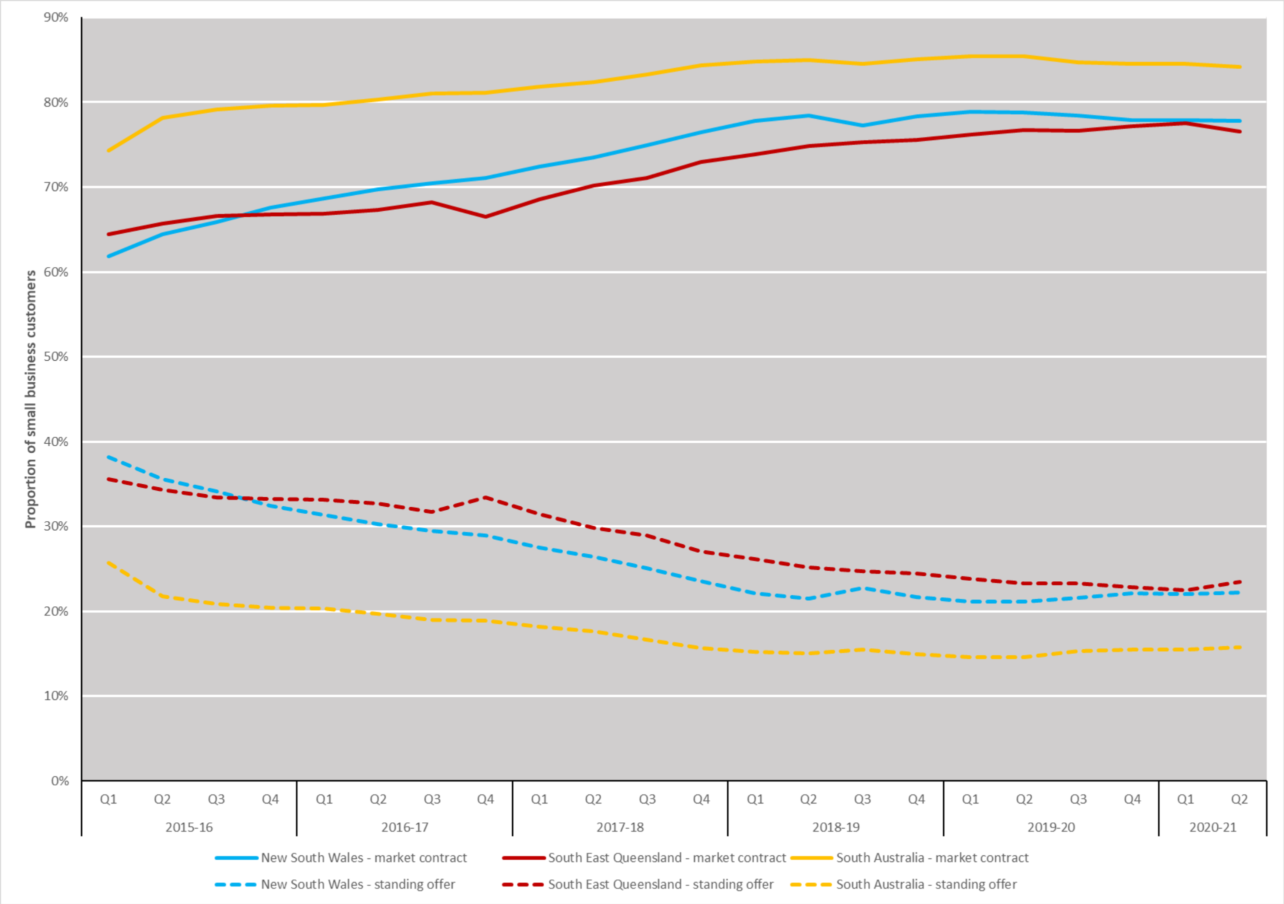
Quarter-by-quarter customer numbers tend to fluctuate, and it is not unusual to see movement in either direction when comparing a change in customer numbers from one quarter to the next. We would be concerned if the observed long-run trend started to reverse over several quarters and we will continue to monitor standing offer customer numbers.

Figure 3: Proportion of residential market and standing offer customer numbers from 2015-16 to 2020-21



Source: AER Retail market performance data, April 2020-21.

Figure 4: Proportion of small business market and standing offer customer numbers from 2015-16 to 2020-21



Source: AER Retail market performance data, April 2020-21.

2.3 DMO regulatory framework

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

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[11] (the model annual usage)[12]

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

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

- 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).[13]

The DMO price cap applies to residential and small business customers on standing offers in distribution regions that are not subject to retail price regulation.[14] These regions are:

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

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

- *Residential customers* – customers on flat rate or time of use tariffs who use electricity mainly for personal, household or domestic use, and whose prices do not include a controlled load (CL) tariff. A CL tariff applies to a separately metered part of a customer's load, for appliances such as electric hot water storage systems or underfloor heating.
- *Residential customers with CL* – customers on flat rate or time of use (TOU) tariffs 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.

Each category includes customers with solar tariffs.

We are not currently required to determine an annual price and usage for other tariff types, such as:

- tariffs with a demand charge
- small business CL and TOU tariffs
- tariffs offered to customers in embedded networks.

The Regulations require us to have regard to a range of specific factors in determining a reasonable annual price. These include wholesale electricity, network and retail costs, the principle a retailer should be able to make a profit, and other matters we

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

14 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.

consider relevant.[15] Our Draft Determination set out how we have had regard to these factors.[16]

The DMO price also functions as a reference price for retailers' advertised offers. Reference price provisions are set out in Part 2 of the Regulations and enforced by the ACCC.[17]

2.4 Our consultation process

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

- On 20 October 2020 we published a Position Paper and received 15 submissions.
- On 29 October 2020 we held an online stakeholder forum attended by about 55 stakeholders. Presentations and Q&A from the forum were published on our website.
- On 17 February 2021 we published a Draft Determination and received 10 submissions. A list of submitters is included at Appendix A.
- On 10 March 2021 we held an online stakeholder forum attended by about 55 stakeholders. Presentations and Q&A from the forum were published on our website.
- We published our consultant ACIL Allen's methodology report on our website.

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 received through our consultations and the advice from our Consultants in making our Determination.

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[15] Regulations, s. 16(4).

[16] AER, DMO 3 Draft Determination, Appendix D, p. 106.

[17] Regulations ss. 10, 12, 14.

3 DMO price determination

This chapter sets out our pricing methodology and reasoning for our DMO 3 price determination. It provides an overview of the DMO 3 pricing methodology, including our consideration of forecast changes in key cost components for 2021-22.

3.1 DMO 3 prices

DMO prices for 2021-22 for each customer type in each distribution region are set out in Table 2 below.[18]

[18] The prices set out in the table are nominal values.

Table 2: DMO prices – 1 July 2021 (including GST, nominal)

Distribution region		Residential without CL	Residential with CL	Small Business without CL
Ausgrid	DMO 3 Price	$1,393	$1,912	$6,900
	for annual usage of	3,900 kWh	General usage 4,800 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 2	-$69 (-4.7%)	-$112 (-5.5%)	-$340 (-4.7%)
Endeavour	DMO 3 Price	$1,609	$2,014	$5,736
	for annual usage of	4,900 kWh	General usage 5,200 kWh + CL 2,200 kWh	20,000 kWh
	Difference to DMO 2	-$102 (-6%)	-$151 (-7%)	-$441 (-7.1%)
Essential	DMO 3 Price	$1,907	$2,271	$7,791
	for annual usage of	4,600 kWh	General usage 4,600 kWh + CL 2,000 kWh	20,000 kWh
	Difference to DMO 2	-$53 (-2.7%)	-$85 (-3.6%)	-$250 (-3.1%)
Energex	DMO 3 Price	$1,455	$1,741	$5,517
	for annual usage of	4,600 kWh	General usage 4,400 kWh + CL 1,900 kWh	20,000 kWh
	Difference to DMO 2	-$53 (-3.5%)	-$71 (-3.9%)	-$243 (-4.2%)
SAPN	DMO 3 Price	$1,716	$2,077	$8,033
	for annual usage of	4,000 kWh	General usage 4,200 kWh + CL 1,800 kWh	20,000 kWh
	Difference to DMO 2	-$116 (-6.3%)	-$167 (-7.4%)	-$272 (-3.3%)

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).[19]

Under the Regulations, retailers must structure their tariffs to not exceed the DMO annual price for the model annual usage.[20] 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 2021-22

This section outlines our pricing methodology for determining DMO 3 prices.

Draft Determination

Our Draft Determination approach was to retain the indexation approach adopted in our DMO 2 determination.

Underlying this approach was our view that the DMO 1 and 2 prices had balanced the DMO policy objectives and are an appropriate starting point for setting DMO 3 prices.

After considering stakeholder feedback, we determined not to make any ‘true-ups’ to the DMO 3 price to reflect variances between our forecast costs and assumptions for 2020-21 and actual costs.[21]

We noted it will be appropriate to review the DMO pricing methodology and underlying assumptions to ensure they remain fit for purpose for future determinations.

Stakeholder submissions

Stakeholders did not raise any new issues in relation to our continuation of the indexation approach.

AGL was generally supportive of the proposed approach we set out in the Draft Determination, given the AER has broadly maintained the methodology used for the 2020-21 DMO. It supported our use of the cost estimates of the previous year’s DMO (with no updating) to determine the appropriate change in cost for this year’s determination.

EnergyAustralia noted the AER’s ‘top-down’ approach to price setting has evolved over the three DMO determinations. While supporting our use of judgement to determine

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19 Regulations, s. 16(1).

20 The ACCC is responsible for compliance and enforcement of the Regulations.

21 See AER, *DMO 3 Draft Determination*, 3.2, p. 26.

DMO price caps and reference pricing in the long-term interests of consumers, it considered our approaches could be improved, in particular:

- we should provide evidence to support our position that the DMO is high enough to accommodate various cost increases
- be more transparent in our approach to step changes
- review our market-based approach to setting Large-scale Generation Certificate (LGC) costs.[22]

No submissions to the Draft Determination specifically addressed the issue of truing-up DMO 2 network prices.

Final Determination

Having considered stakeholder feedback, our Final Determination position is unchanged from the approach we proposed in our draft, to continue the indexation approach for DMO 3.

The next section discusses our consideration of a DMO methodology review.

3.2.1 DMO methodology review

In developing the DMO 'indexation' methodology, we did not set out a specific end date or 'reset' point.

The Draft Determination noted:

- it would be important to review the DMO pricing methodology and assumptions, to ensure they remain appropriate to the DMO objectives
- it would be important to address and consult on these issues holistically
- a review was an opportunity to consider issues that were fundamental to our calculation of the DMO 1 price components. These include issues such as the hedging approach of our assumed retailer, our indexation approach, as well as the annual usage amounts for residential and small business customers, which may change over time.

We will undertake our DMO methodology review during 2021, as part of our DMO 4 consultation, and with any resulting changes in approach implemented in the DMO 4 determination.

We intend to release a consultation paper setting out issues and options for consideration in our methodology review by August 2021. Given the scope of matters we may consult on is likely to be greater than our standard DMO consultation, an

[22] EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 2.

earlier start to the DMO 4 consultation will afford us additional time to request information and conduct analysis to inform our positions, if needed.

DISER has committed to a review of the Regulations, which will commence in the second half of 2021. The DISER review will have a different focus to ours, and will considering changes that may be needed in the DMO Regulations.

We will work with DISER to align both reviews, to avoid duplication of scope, and minimise the impact on stakeholders. Any changes to the Regulations resulting from the DISER review, and any changes to the DMO methodology resulting from our review, will be taken into account in our DMO 2022-23 (DMO 4) price determination. These will take effect on 1 July 2022.

3.3 Forecast changes in cost inputs in 2021-22

Our forecasts of changes to the cost components between 2020-21 and 2021-22, and the relevant impact on DMO prices in each of the distribution regions, are set out in Table 3 below.

Table 3: Forecast changes in cost components and DMO bill impact – 2020-21 to 2021–22 (including GST, nominal)

Description	Network cost	Wholesale cost	Environ-mental cost	Overall price impact from DMO 2020–21 (%, $)		DMO 2021-22
Residential without CL						
Ausgrid	+3.1%	-20.8%	+11.6%	**-4.7%**	*-$69*	**$1,393**
Endeavour	+1.8%	-21.4%	+11.2%	**-6.0%**	*-$102*	**$1,609**
Essential	+5.4%	-22.4%	+10.4%	**-2.7%**	*-$53*	**$1,907**
Energex	+3.4%	-19.1%	+10.9%	**-3.5%**	*-$53*	**$1,455**
SAPN	+3.1%	-22.5%	+9.8%	**-6.3%**	*-$116*	**$1,716**
Residential with CL						
Ausgrid	+2.7%	-20.4%	+11.6%	**-5.5%**	*-$112*	**$1,912**
Endeavour	+2.0%	-20.9%	+11.2%	**-7.0%**	*-$151*	**$2,014**
Essential	+5.6%	-22.7%	+10.4%	**-3.6%**	*-$85*	**$2,271**
Energex	+3.2%	-18.7%	+10.9%	**-3.9%**	*-$71*	**$1,741**
SAPN	+1.8%	-22.3%	+9.8%	**-7.4%**	*-$167*	**$2,077**
Small business without CL						
Ausgrid	+4.1%	-20.8%	+11.6%	**-4.7%**	*-$340*	**$6,900**
Endeavour	+1.2%	-21.4%	+11.2%	**-7.1%**	*-$441*	**$5,736**
Essential	+5.4%	-22.4%	+10.4%	**-3.1%**	*-$250*	**$7,791**
Energex	+3.9%	-19.1%	+10.9%	**-4.2%**	*-$243*	**$5,517**
SAPN	+13.8%	-22.5%	+9.8%	**-3.3%**	*-$272*	**$8,033**

Note: Overall price impact includes residual cost adjusted for CPI (1.5%) in 2021-22.

The key drivers for these changes are:

- Wholesale costs comprise **wholesale energy costs** associated with hedging and spot market costs, as well as **other energy costs** incurred in participating in the NEM wholesale market.[23] The overall impact of the forecast changes in **wholesale energy costs** and **other energy costs** is presented above.

The key drivers of change in **wholesale energy costs** are the substantial reductions observed in forward contract prices and the change in the shape of load profiles, leading to significant reductions in wholesale energy costs for all DMO regions.

- Our Consultant noted that, compared with 2020-21, futures-based contract prices for 2021-22, on an annualised and trade-weighted basis to date have:
  - decreased by about $13.80/MWh for Queensland
  - decreased by about $15.20/MWh for New South Wales
  - decreased by about $21.10/MWh for South Australia.

  Two main factors are driving these reductions:
  - the continued strong increase in renewable investment coming on-line between 2020-21 and 2021-22, with about 4,000 MW of renewable investment entering the NEM over the next 12-18 months
  - the continuation of lower gas prices for gas fired generation. Spot prices across the east coast gas market have maintained their lower levels over the past 12 months.
- **Other energy costs** are forecast to decrease across most distribution regions between 2020-21 and 2021-22. The most significant change in other energy costs are the costs associated with ancillary services, which declined across all regions and tariff types in response to an increase in supply of new entrant capacity able to participate in this relatively small market.
- **Environmental costs** are forecast to increase across all regions and for all customer and tariff types. The increase is primarily driven by the higher binding and forecast Small-scale Technology Percentage (STP). This is due to expectations that small-scale installations will continue to increase in 2021-22, driving up the cost of Small-scale Renewable Energy Scheme (SRES) compliance costs by about $2.21/MWh or 24 per cent.

  This increase is partly offset by a projected decline in the cost of the Large-scale Renewable Energy Target (LRET) between 2020-21 and 2021-22, of about 15 per cent (or $0.74/MWh) as a result of declining LGC forward prices and the lower Renewable Power Percentage (RPP). We have however, observed strong demand for LGCs in recent quarters driven by shortfall charge refunds and voluntary surrenders, leading to an uptick in recently traded LGC prices. The cost variations by region mainly result from differences in jurisdictional energy efficiency schemes.

[23] 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.

- **Network costs** increased across all regions. As all DMO regions are within a regulatory control period, the approved distribution revenues are smoothed across the five-year period. This allows for relatively predictable network price movements each year. Changes to yearly revenue of the distribution and transmission businesses also occur as a result of under-recovery or over-recovery in previous years, annual incentive rewards/penalties, approved pass through amounts and changes in the annual return on debt. For example, the increases in Transgrid's transmission charges have been passed on through the network charges for Ausgrid, Endeavour and Essential customers.

  Changes to the mix of the daily charge and usage tariffs can also affect the network costs. For residential customers without controlled load, the forecast change to network costs range from a 1.8 per cent increase in the Endeavour region to a 5.4 per cent increase in the Essential region in 2021-22. For small business customers the forecast changes range from a 1.2 per cent increase in the Endeavour region to a 13.8 per cent increase in the SAPN region.[24]

- **Residual costs** increased by 1.5 per cent across all regions based on the RBA's February 2021 Consumer Price Index inflation forecast for the 2021-22 period. Our analysis and consideration of submissions has not identified any increase or decrease in retail costs that would warrant a step change. Our consideration of step changes is discussed in section 3.3.4. We considered introducing a productivity factor to residual costs, but have decided not to apply it for this determination.

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 accompanying this determination.[25]

3.3.1 Wholesale

Overview

Under the methodology used by our Consultant, forecast wholesale energy costs are a function of projected energy supply and demand forecasts, hedging strategy and any residual exposure to forecast spot market prices.

The demand-side forecast is a function of AEMO's Electricity Statement of Opportunities (ESOO) central scenario[26], estimated uptake of rooftop solar photovoltaic (PV) and weather simulations in respect to their impact on demand and availability of renewable resources.

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24 These changes are relative to the indicative network prices we used to calculate the DMO 2 price. Therefore these are not the actual change in final approved network costs for 2021-22.

25 ACIL Allen, *Default Market Offer 2021-22 final determination technical report*

26 AEMO, *2020 Electricity Statement of Opportunities*, August 2020: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-ofopportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2

The supply-side forecast, which is broadly aligned with AEMO's Integrated System Plan, takes into consideration announced new investments, retirements, fuel costs and simulated thermal power generation availability. Our Consultant takes the above demand-side and supply-side forecasts to produce a distribution of around 500 simulated spot market price outcomes, representative of volatility in the spot market.

Distribution Loss Factors (DLF) for each network area and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the WEC estimates to incorporate any losses.

Other energy costs include hedging costs, AEMO NEM management fees, Reliability and Emergency Reserve Trader (RERT) costs and ancillary services charges for services to manage power system safety, security and reliability.

Details of the Consultant's wholesale cost forecasting methodology and resulting wholesale and energy costs forecasts are set out in its *Default Market Offer 2021-22 final determination technical report*.[27]

Draft Determination

Our Draft Determination proposed to maintain the methodology, approach and assumptions to wholesale cost forecasting as used in the DMO 2 Final Determination.

On assumed **hedge book build period** and **setting of wholesale energy cost forecast**, the proposed approach in our DMO 3 Draft Determination was to maintain the approach of:

- taking into account forward contracts from the first trade
- setting the wholesale energy cost (WEC) at the 95th percentile of forecast outcomes.

We investigated the feasibility of **developing separate residential and small business load profiles,** which some stakeholders considered would provide more accurate wholesale energy cost forecasts for the different customer types, compared to the Net System Load Profile (NSLP).

Noting limitations and uncertainty with the data, and stakeholder preferences for stability and consistency, our Draft Determination was to continue to use the AEMO NSLP and Controlled Load Profile for wholesale cost forecasting.[28]

Our Draft Determination position was to forecast **ancillary services charges** by the relevant DMO region.

We did not include **AEMO Directions costs** in our wholesale cost forecast for South Australia.

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[27] ACIL Allen, *Default Market Offer 2021-22 final determination technical report.*

[28] See AER, *DMO 3 Draft Determination*, 3.3.1, p. 34.

Stakeholder submissions

AGL supported our adoption of a largely unchanged wholesale cost forecasting approach in DMO 3 noting the importance of methodology consistency, while also supporting our approach to allocate ancillary services charges.[29]

In relation to AEMO Directions costs, AGL considered our reasons for excluding them from the Draft Determination are not justified. It noted:

- AEMO Directions cost were 'immaterial' prior to the calculation of the initial DMO, therefore we would not have to perform any complex re-indexing of previous DMO calculations to accurately reflect this cost.[30]
- While the installation of synchronous condensers in South Australia will decrease the frequency of AEMO Directions:
    - It is not certain they will be operational prior to the DMO 3 period
    - The cost of directions are still likely to be material. It cited evidence of ongoing cost to retailers of $12 million per annum, even after synchronous condensers are operational.[31]
- Our decision to not include directions costs is inconsistent with our approach to forecasting other uncertain energy costs, such as ancillary services and RERT, which use the previous 12 months costs as a basis for forward estimates.[32]

EnergyAustralia's submission on wholesale cost forecasting sought guidance on how a binding Retailer Reliability Obligation, if and when issued, will affect the wholesale cost estimation methodology in the future.[33]

Momentum Energy disagreed with our decision not to develop separate residential and small business load profiles. It noted that the load profiles of residential and small business customers are no longer similar and assessing each independently would remove cross subsidies in the DMO pricing. It attached information indicating that most small business customers use most of their electricity during the day when prices are lower whereas peak residential loads occur in the evening.[34]

Queensland Energy Users Network (QEUN) were concerned about the timing difference between publication of AER's DMO and Queensland Competition Authority's (QCA) Regulated Electricity Price (REP) resulting in slightly divergent wholesale cost

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29 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 1, 3.

30 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 2.

31 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 2.

32 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 2.

33 EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 2 and 12.

34 Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p. 4-5.

forecasts. QEUN also raised concerns about our reliance on a single consultant to make those forecasts, which it considered may not reflect broader market views on wholesale energy cost trends.[35]

Final Determination

Having considered stakeholder submissions, our DMO 3 Final Determination position is to maintain the same overall approach and assumptions to wholesale cost forecasting as in the DMO 2 Final Determination.

The single change from our DMO 2 approach is to allocate ancillary services costs at a regional level, as outlined in the DMO 3 Draft Determination.

During our DMO 3 Position Paper and Draft Determination consultations, stakeholders supported the DMO 2 Final Determination approach to forecasting wholesale costs and noted the importance of maintaining consistency between DMOs. Forecast wholesale costs in this DMO 3 Final Determination used updated market data up to 1 April 2021.

The DMO methodology review that will be part of our DMO 4 consultation will provide an opportunity to reconsider our approach and assumptions to wholesale cost forecasting. Noting QEUN's concerns, we may consider how our forecasts may be able to reflect a broader range of views.

AEMO Directions cost

Having considered the additional information provided by AGL, we have not changed the position proposed in our Draft Determination, which was not to include AEMO Directions costs in our DMO calculations, and reconsider them as part of the DMO methodology review.

As set out in the Draft Determination, we have not previously included these costs. Under our indexation approach, including a new cost at this stage would impact the comparability and consistency of the index.

We note uncertainty about the synchronous condensers, including the ongoing potential for AEMO directions, and hence costs, after the new technology becomes operational.

Our view remains that the appropriate point to consider these issues will be as part of the DMO 4 methodology review.

Retailer Reliability Obligation

The triggering of the Retailer Reliability Obligation (RRO) would require retailers in the given quarter and region to secure sufficient qualifying contracts to cover their share of a one-in-two-year (P50) peak demand. As part of the current wholesale energy cost forecasting methodology, an algorithm is run by ACIL Allen to determine the optimal hedge cover for a given distribution zone for each quarter.

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[35] Queensland Energy Users Network, *Verbal submission to DMO 3 Draft Determination*, 22 March 2021.

In the Consultant's report, ACIL Allen proposed an approach to account for the triggering of the RRO. This is to, as part of the algorithm to determine optimal hedge cover, increase the overall level of contract cover to 100 per cent of P50 annual peak demand if the overall level of the optimal contract cover is less than 100 per cent.

In the instance that the overall level of the optimal contract cover is equal to or greater than 100 per cent of the P50 annual peak demand, then no change or action would be required to capture the impact of the RRO on the forecast wholesale energy cost.

The above approach will be adopted to forecast wholesale energy costs for a region when the RRO is triggered.

Separating residential and small business load profiles

The information provided by Momentum Energy is generally consistent with our analysis of the interval meter data we received from AEMO, where small business interval load profile showed a marked difference from the NSLP, with peak demand occurring around midday as opposed to late afternoon and evening.

Having considered Momentum Energy's information, we have not changed our Draft Determination position. The key points of this position were:

- due to the current prevalence of accumulation meters in DMO jurisdictions, NSLP and CLP continue to represent the best reflection of broader residential and small business energy usage patterns.
- due to uncertainty around the amount of solar and CL customers captured, using the AEMO data may risk understating actual demand.
- a large majority of customers in the DMO regions are on accumulation meters, with settlement based on the NSLP. Therefore, we cannot be confident that the interval load profiles, based on usage from the minority of customers with type 4 and 5 meters, would be a reasonable representation of the broader residential and small business customers' usage patterns.

We may reconsider this issue as part of our review of the DMO methodology. It is possible that data improvements (such AEMO upgrading its systems with the move to 5MS) may remove some practical challenges, and provide us with another opportunity to review and re-investigate this matter.

Wholesale cost inputs

For comparison, the wholesale cost inputs provided by the Consultant for the 2021-22 period are given in Table 4, together with inputs for the 2020-21 period used in the DMO 2 Final Determination.

Table 4: Wholesale costs for 2020-21 and 2021-22, $/MWh (excluding GST, nominal)

Distribution region	Tariff	2020-21	2021-22
Ausgrid	Flat rate	111.06	**87.94**
	CL1	74.02	**60.44**
	CL2	72.11	**57.47**
Endeavour	Flat rate	112.27	**88.27**
	CL1	103.92	**83.29**
	CL2	103.92	**83.29**
Essential	Flat rate	103.50	**80.34**
	CL1	87.90	**67.30**
	CL2	87.90	**67.30**
Energex	Flat rate	91.49	**74.03**
	CL1	72.29	**58.84**
	CL2	74.06	**61.18**
SAPN	Flat rate	154.12	**119.47**
	CL1	93.15	**72.82**

Source: Default Market Offer 2021-22 final determination technical report.

3.3.2 Environmental costs

Overview

Environmental schemes at both 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 are 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. Retailers have an obligation to purchase renewable energy certificates and surrender them to the Clean Energy Regulator in proportion to the overall amount of energy consumed by their customers.

The RET is made up of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). LRET costs are incurred by retailers to acquire the necessary amount of LGCs. Required LGC surrender for each retailer is determined by the electricity consumed by a retailer's customers in that year, multiplied by the RPP set annually for a calendar year.[36]

Similar to the LRET, under the SRES, Small-scale Technology Certificates (STCs) are required to be surrendered by retailers based on the STP[37] set annually for a calendar year, and the amount of electricity consumed by a retailer's customers in that year. Retailers have the option to either purchase STCs on the market or from the STC Clearing House at a set price.

In addition to the RET costs, a retailer also incurs a small amount of jurisdictional green scheme costs, which are passed onto their customers. These include the New South Wales Energy Savings Scheme (ESS) and South Australian Retailer Energy Efficiency Scheme (REES).

Draft Determination

Our DMO 3 Draft Determination approach proposed to retain the market-based approach adopted in the DMO 2 Final Determination to forecast environmental costs.

We noted we assess both the Clean Energy Regulator's (CER) non-binding **STP** estimate and our Consultant's estimate when determining the STP to use in our SRES cost forecast for the Final Determination.

We considered whether to apply the **LGC floor price**, tied to the price of an Australian Carbon Credit Unit (ACCU), as well as whether to take into account Power Purchase Agreement costs through a weighted average cost approach, but in the end determined to maintain our existing methodology.

Stakeholder submissions

AGL agreed that the current level of LGC prices for 2021 and 2022 will not require the setting of an **LGC floor price** for DMO 3, but noted the setting of an LGC floor price could be explored further as part of the Regulations and DMO methodology reviews.[38]

EnergyAustralia re-stated its view that it is not appropriate for us to rely on market traded LGCs as a fair price for all LGCs, and provided information challenging our previously-stated assumption that market-based LGC prices are reasonable to use because they account for a significant proportion of required LGC surrenders. It noted:

- trade data we previously quoted were not for unique certificates and were for LGC certificates of all vintages

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36 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-renewable-power-percentage, viewed 22 March 2021.

37 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage, viewed 22 March 2021.

38 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 3.

- data sourced directly from TFS (the broker) showed 4 million of 2019 vintage LGCs were traded in 2019 and 14 million of 2019 vintage LGCs were traded at any time
- that trades in 2019 only represented 13 per cent of the LRET target, and not over the 200 per cent as suggested by the AER.[39]

Final Determination

Having considered stakeholder submissions, our DMO 3 Final Determination retains the approach proposed in the DMO 3 Draft Determination and DMO 2 Final Determination to forecast environmental costs.

In March, the CER released the RPP [40] and binding STP for 2021, as well as the non-binding STP estimate for 2022.[41] As discussed in the Draft Determination, we have assessed the CER's published percentages against our Consultant's estimates. For this DMO 3 Final Determination, we have used CER's published 2021 percentages and our Consultant's estimates for 2022 percentages to calculate LRET and SRES costs, as we believe these are most representative of costs incurred by retailers. Forecast environmental costs in this DMO 3 Final Determination also used updated market data up to 1 April 2021.

LGC floor price

The question of a LGC floor price using AGL's proposed approach would be academic for DMO 3. CER's December 2020 Quarterly Carbon Market Report[42] showed LGC forward prices continued to incrementally rise. Calendar year 2021 and 2022 LGC prices, which are relevant for DMO 3, are all still significantly above AGL's previously proposed floor price.

As noted in our Draft Determination, other Government Agencies and Regulators are considering policy initiatives in response to the King Review recommendations, one of which is for a carbon exchange rate for LGCs[43] – effectively tying the price of LGCs to Australian Carbon Credit Units as suggested in AGL's submission. Market prices for LGCs would reflect any future Government policy initiative.

Therefore, as part of the DMO, we have retained our market-based approach to forecasting LGC prices. It will be appropriate to leave any carbon exchange policy and framework setting to the relevant Government agency to undertake, and thus would be unlikely to consider it as part of our upcoming DMO methodology review.

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39 EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 10-11.

40 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-renewable-power-percentage, viewed 26 March 2021.

41 See CER website: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage, viewed 26 March 2021.

42 See CER website: http://www.cleanenergyregulator.gov.au/DocumentAssets/Pages/Quarterly-Carbon-Market-Report---Quarter-4-December-2020.aspx, viewed 22 March 2021.

43 See Department of Industry website: https://www.industry.gov.au/data-and-publications/government-response-to-the-expert-panel-report-examining-additional-sources-of-low-cost-abatement, viewed 7 April 2021.

Setting the LGC price

We retain our Draft Determination position analysis that market-traded LGC prices are transparent, publicly available and a function of market conditions, and are the best available proxy for the cost of acquiring LGCs.

In response to EnergyAustralia's submission, we note:

- Our market-based trade-weighted approach to setting the LGC price takes into account trades from the date of the first trade.
- LGC trade data sourced by our Consultant aligns with EnergyAustralia's submission, in that roughly 14 million 2019 vintage LGCs were traded from the date of first trade up to the required surrender date of 14 February 2020.
- The roughly 14 million traded 2019 vintage LGCs represented more than 40 per cent of the required surrender amount (31 million LGCs) for 2019.
- As our market-based trade-weighted approach to setting the LGC price takes into account trades from the date of the first trade, this accounts for over 40 per cent of LGCs required to be surrendered in 2019, and not the 13 per cent noted in EnergyAustralia's submission.
- The trade data our Consultant sourced from TFS also showed the volume of trades in LGCs for the 2020 to 2022 surrender years are increasing each surrender year, demonstrating higher market liquidity as increased renewable generation leads to a growing supply of LGCs.

Noting the above, for our DMO 3 Final Determination, we have retained our market-based trade-weighted approach to setting the LGC price adopted in the DMO 2 Final Determination.

Environmental cost inputs

The environmental cost inputs provided by the Consultant for the 2021-22 period are given below, along with inputs for the 2020-21 period as used in the DMO 2 Final Determination for comparison.

Jurisdictional scheme costs and network losses vary between distribution regions. As a result, total forecast environmental costs ($/MWh) vary across regions as indicated in Table 5.

Table 5: Environmental costs for 2020-21 and 2021-22, $/MWh (excluding GST, nominal)

Distribution region	Tariff	2020-21	2021-22
Ausgrid	Flat rate	17.17	**19.17**
	CL1	17.22	**19.22**
	CL2	17.22	**19.22**
Endeavour	Flat rate	17.36	**19.31**
	CL1	17.36	**19.31**
	CL2	17.36	**19.31**
Essential	Flat rate	17.25	**19.04**
	CL1	17.25	**19.04**
	CL2	17.25	**19.04**
Energex	Flat rate	15.10	**16.75**
	CL1	15.10	**16.75**
	CL2	15.10	**16.5**
SAPN	Flat rate	18.57	**20.39**
	CL1	18.57	**20.39**

Source: Default Market Offer 2021-22 final determination technical 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

Our Draft Determination position on network tariffs was that we would use the AER approved 2021-22 network pricing proposals if these are available at the time of finalising the DMO calculations in late April.

If there are no approved prices available, we indicated we would use network pricing proposals, which must be submitted by 30 March each year. We still consider this is the best alternative to approved tariffs as prices are unlikely to change significantly before being approved.

If the pricing proposals are delayed by the network businesses, or they are undergoing AER assessment at the time of the DMO 3 Final Determination, we would have regard to the latest available indicative network tariffs.

In determining the changes in network costs, we intended to pass through changes in the applicable network tariffs outlined in Table 6. These are consistent with the network tariffs/codes used in previous years.

Table 6: Network tariffs (with network codes) to assess the change in network costs

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
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
SAPN	Residential Single Rate RSR (SR)	Residential Single Rate RSR (CL)	Business Single Rate BSR

Stakeholder submissions

Stakeholders generally supported our approach to use annual pricing proposals for network tariffs for DMO 3. If the proposals have not been approved, AGL and Origin supported using the submitted proposals rather than the previous year's indicative estimates.[44]

In our Draft Determination we referred to the annual pricing proposals 'undergoing AER assessment'. Origin has sought clarification when we would use submitted proposals rather than latest available indicative tariffs.[45]

AGL also supported the AER modelling which uses the network price estimates of the previous year's DMO (with no updating) to calculate and determine the appropriate change for the 2021-22 DMO.[46]

Alinta Energy and Momentum both commented on the problematic timing of the annual pricing proposals and presented potential solutions. Alinta Energy submitted that the misalignment of approved network tariffs and the DMO Final Determination is an ongoing and avoidable challenge.[47] Momentum submitted that the AER is unlikely to regularly have the approved network tariffs prior to the DMO Final Determination.[48]

To address the timing misalignment, Alinta Energy suggested we publish the final network tariffs earlier, in time for the DMO Final Determination. As the DMO has set timeframes in the Regulations, the annual pricing process could be brought forward as to allow final tariffs to be approved in time for the DMO. This would also apply to the network regulatory reset process, resulting in the most up-to-date CPI not being applied to the network tariffs. Alinta states that the impact of this option is less significant than applying the proposed network tariffs.[49]

Momentum submitted we should consider initiating a rule change in relation to the network pricing proposals to ensure the approved network tariffs are used in the DMO. Momentum also suggested that a new network pricing timeline should be mandated for the five key tariffs used in the DMO.[50]

SA Power Networks highlighted that network businesses have limited flexibility in the timing of their annual pricing proposals, as the timelines are set out in the National Electricity Rules.

During a non-reset year, such as DMO 3, the network annual pricing proposals can be incorporated into the DMO cost stack. During a regulatory reset year (every five years) the annual pricing proposal cannot be completed until after 30 April.[51] Therefore it is

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44 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 1. Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 4.

45 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 4.

46 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 3.

47 Alinta Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 2.

48 Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p. 4.

49 Alinta Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 2.

50 Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p. 4.

51 National Electricity Rules 6.11.2 Notice of distribution determination. The AER must as soon as practicable, but not later than 2 months before the commencement of the relevant regulatory control period, publish [the distribution determination].

not possible for annual pricing to be incorporated in the DMO cost stack for that year. In addition, there may be unavoidable delays in the network annual pricing proposal when transmission networks are undergoing a regulatory reset.[52]

EnergyAustralia, Origin and Momentum noted that our use of indicative network tariffs had led to us underestimating network charges in DMO 2, and that we had not compensated retailers for this in the DMO 3 price.[53]

Final Determination

Our network cost forecasts for 2021-22 are based on the network annual pricing proposals for 2021-22.

At the time of publication, the AER had not approved the network businesses annual pricing proposals in time for the Final Determination.

Consistent with the position set out in the Draft Determination, we have used tariffs from the submitted network pricing proposals as this represents the best information available at the time of our Final Determination.[54] This approach is generally supported by retailers.

However, there remains a possibility that the submitted pricing proposals will change due to updates in forecast demand or other calculation amendments.

We have not made any adjustments to the DMO 3 price to reflect the difference in the indicative New South Wales, South Australia and South East Queensland tariffs we used for the DMO 2 determination and the final approved network tariffs. Our reasons remain the same as we set out in the Draft Determination.[55]

Recovery of the National Transmission Planner (NTP) cost was previously undertaken by AEMO, and accounted for under other wholesale costs in the DMO. For 2021-22, the recovery of this cost transferred from AEMO to each of the Transmission Network Service Providers (TNSPs) directly. Accordingly, for DMO 3, NTP costs no longer form part of other wholesale costs, but are accounted for in network costs. NTP cost forms part of the Transmission Use of System (TUOS) charges that are passed through into distribution network prices for 2021-22.

Origin sought clarification about when we would use tariffs from submitted proposals rather than the latest available indicative tariffs from the previous year. We consider

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National Electricity Rules 6.18.2(a)(1) Pricing Proposals. The distribution business has 15 business days to submit the initial pricing proposal after publication of the distribution determination.

52 SA Power Networks, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 1.

53 EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 7; Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 2; Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p. 4.

54 If the annual pricing proposal has been re-submitted, then we use the latest version.

55 AER, *Draft Determination, Default market offer prices 2021-22*, 17 February 2021, p. 30.

that if annual pricing proposals are in the final stages of being approved that these are the best available tariffs. Should there be concerns that the network annual pricing proposal is deficient or that an amended pricing proposal will need to be submitted, we consider that indicative prices from the previous approved annual pricing proposal would be the best available tariffs.[56]

With regards to the timing of network annual pricing proposals and the DMO Final Determination, we note the final DMO date is set out in the Regulations, which would need to be revised by the Commonwealth Government to allow a later date.

In regard to Momentum's suggestion that approvals for tariff types relevant to the DMO be prioritised for early approval, it is unlikely that these tariffs can be separated out from the annual pricing proposal. This is because the annual pricing proposal is considered in full and some tariff types are interrelated. A change in the total revenue allowed due to updated numbers may flow on to a change in multiple network tariffs for certain customer groups.

3.3.4 Residual costs and the step change framework

Overview

We identify other costs that make up the DMO price, apart from wholesale, environmental and network costs, as retail residual costs. While we do not specify individual costs, the retail residual component of the DMO price includes costs that are incurred by retailers to acquire, service and retain customers, meet regulatory obligations, as well as a nominal profit margin.

Under our indexation approach, we index the residual component we calculated from our DMO 1 determination by the forecast change in the Consumer Price Index (CPI).

Our indexation methodology also incorporates a step change framework. This enables us to adjust the DMO price to account for changes in retail costs that, in exceptional circumstances, are not accurately reflected by applying a general rate of change adjustment.

For us to consider an adjustment under the step change framework any cost must:

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

56 National Electricity Rules 6.18.8 Approval of pricing proposal.
Necessarily, this will require judgement as to whether the proposed prices may change significantly with re-submission.

Given the DMO 1 residual component – which we set based on retail prices in October 2018 – is assumed to include some costs to meet regulatory obligations, our starting position in considering any step change is that only exceptional circumstances are likely to require explicit compensation under the framework.

This also applies to our consideration of COVID-19 related debt costs, as the DMO 1 residual is assumed to include some costs for bad and doubtful debt.

While we have not previously defined 'materiality', our view is that incremental cost changes due to new regulatory requirements, for instance, would generally be compensated by the residual CPI indexation.

Importantly, unlike other Australian regulators' energy retail price approaches, the DMO price was not set based on retailers' efficient costs, with a set retail margin allowance.

Under our 'top down' approach to price setting, the DMO price was initially set in reference to standing and market offer price, at a point well above the level of most market offers. For this reason, it is not necessary for us to account for all new efficient costs in order to be satisfied that retailers have a reasonable margin.

This determination clarifies our position that a 'material' impact is one that would mean the DMO price was not achieving the policy objectives. Our consideration of retailer cost information is set out below.

Adjustments or allowances made under the step change framework are separate to the residual cost component, and not subject to indexation. Any step change adjustment or allowance would apply for one DMO period only.

Where a step change spans multiple DMO periods, retailers would need to demonstrate the cost changes remain material for the subsequent period.

We sought stakeholders' views on the possible impact on retailers' costs from COVID-19 related bad and doubtful debt, the implementation of CDR and other matters.

Retailers also raised the matter of increasing costs to service customers with advanced meters, resulting from the Power of Choice regulatory reforms introduced in 2017, for us to consider under the step change framework.

We also considered whether there was available information to support us applying a productivity adjustment to the DMO price to reflect any reduction in retailer costs due to increased efficiency over time.

Draft Determination

In our Draft Determination, we considered information provided by retailers about changes to the retail costs due to COVID-19, advanced meters and regulatory costs. In response to our request to provide evidence of costs and impacts, including any cost decreases, retailers generally provided limited information. Based on the available information, we did not make any adjustment to the DMO draft price.

- We estimated increased bad and doubtful debt costs due to COVID-19 at $10 per customer, and noted that this level of costs was not sufficient to warrant a change to the DMO price under the step change framework. We noted we were open to considering further information about the impact of COVID debt.
- CDR reforms are being rolled out in the electricity sector and will come into effect during the DMO 3 period. Limited information provided meant we were unable to estimate retailers' costs for CDR in 2021-22.
- Retailers provided limited information about the impact of 5MS reforms on their costs. The information available suggested these costs would not be significant enough to warrant adjustment as a step change.
- Retailers did not provide information that would allow us to assess their costs to service customers with advanced meters. Our position was that due to the limited penetration of advanced meters among standing offer customers (around 10-20 per cent), retailers could absorb any costs without impacting the DMO policy objectives.
- Retailers generally did not provide information about cost decreases. Consumer groups noted that due 'information asymmetries' between retailers and stakeholders, they were unable to substantiate the accuracy of cost information.

In relation to productivity, we considered a number of different sources of published information in determining not to apply a productivity adjustment to the DMO.

- Publicly available ACCC industry data[57] and retailer annual reports did not provide enough detail about capital and other costs we would need in order to understand whether cost reductions were due to productivity increases.
- ABS productivity data suggests productivity growth in the electricity retail sector is not materially different from the overall economy. A productivity factor based on this data would be zero, that is, it would have no effect on the DMO price.

Stakeholder Submissions

Cumulative impact of cost increases

A key theme in retailer submissions was concern about the cumulative impact of the identified cost increases, which they considered was material for the purposes of the step change framework.

Some retailers provided confidential information about increases to their retail costs, due to external factors, since the DMO commenced in July 2019. Our analysis of this new information is included in the next section.

[57] The ACCC's Electricity Monitoring Inquiry publishes information about retailers' costs. See https://www.accc.gov.au/regulated-infrastructure/energy/electricity-market-monitoring-2018-2025

Several submissions considered that requiring retailers to absorb these cost increases and not accounting for them in the DMO 3 price, would be detrimental to the DMO policy objectives.

For instance, the Australian Energy Council (AEC) noted the DMO is not intended to be a low priced offer, but a fall back to protect disengaged customers. Therefore retailer headroom[58] should not be eroded by not including allowances in the DMO price for incremental cost increases. It suggested that if retailer margins fall to an unsustainable level, competition will be reduced to the detriment of customers.[59]

AGL expressed a similar view, suggesting not allowing for COVID-19 and other regulatory costs incurred by retailers 'may threaten the objectives of the DMO'.[60]

Alinta Energy suggested cost increases, including COVID-19 and other regulatory cost increases, will materially affect retailer margins during the DMO 3 period.[61]

EnergyAustralia considered if an allowance for retailer cost increases, including COVID-19 related costs, is not made in the DMO 3 price, the DMO objective of enabling retailers to recover efficient costs and make a reasonable profit is not likely to be met.

EnergyAustralia also noted cost allowances for retailer costs incurred in 2020 were not compensated. It urged us to seek to quantify unknown future costs and provide an allowance in the forward DMO price to avoid undercompensating retailers in the future.[62]

Momentum Energy considered these step change costs should be included in the DMO 3 price because there is no true-up mechanism to compensate retailers in future price determinations for previous cost under-recovery.[63]

Origin Energy considered the DMO objective of enabling retailers to recover efficient retail costs plus a reasonable margin is not achieved by excluding retailer costs, such as COVID-19 and advanced meter costs, in the DMO 3 price.[64] It considered, 'the goal is not to drive cost allowances to an unsustainable level or deny retailers an appropriate profit margin'.[65]

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58 In this context 'headroom' is considered any money left under a price cap for the purpose of innovation or competition, after efficient costs and reasonable profit are accounted for.

59 AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.2.

60 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1.

61 Alinta Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.2.

62 EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.8.

63 Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p.1.

64 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1.

65 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.3.

Origin Energy considered the decision not to take retailer costs into account is arbitrary and increases regulatory risk.[66] It also suggested, 'failure to make adequate allowance for legitimate costs impacts all retailers but is likely to have a disproportionate impact on smaller retailers'.[67]

Simply Energy considered we should account for the cost increases, to maintain retailer margins at current levels.[68] To achieve this it considered the step change framework be used to capture all additional costs above the CPI adjustment applied to the residual price component.[69]

Simply Energy was concerned that if COVID-19 and other related costs are not included in the DMO 3 price, this will affect the consistency and comparability of the DMO price over time. For example, higher retailer costs would mean reduced market offer discounts, giving customers the impression current market offers are more expensive, reducing incentives for customers to switch and participate in the market.[70]

While this scenario could potentially occur when comparing a retailer's prior market offers available during DMO 2 with the same retailer's latest market offers available during DMO 3, we do not think this situation is likely to occur when comparing offers between retailers.

Retailers urged the AER to make an allowance for costs in the DMO 3 price, rather than waiting to address these matters in the DMO 4 methodology review.

PIAC strongly supported our Draft Determination position to not make allowances for COVID-19 and other step change costs. PIAC argued the DMO is set intentionally above efficient costs to serve, including a profit margin and significant additional headroom. PIAC also noted that the retail cost component has increased over time, as it is indexed with inflation, regardless of whether actual retail costs have increased since setting the initial DMO.[71]

Median market offer (MMO) as a proxy for efficient costs

Some retailers argued our reliance on the median as a proxy to understand whether the DMO price is above 'efficient cost', which has been an important element of our analysis of the DMO impact, would lead to us over-estimating the DMO's margin above efficient costs, and therefore the impact on retailers' margins.

For instance, EnergyAustralia noted that offers in Energy Made Easy at a point in time (the basis for our price analysis) are 'acquisition offers' that do not reflect the true costs to serve a customer over the duration of a contract. We have previously noted that the

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66 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1.

67 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.3.

68 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.2.

69 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.2.

70 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.2.

71 PIAC, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1.

median offer is likely to have been driven lower in 2020 by smaller retailers that are capturing market share and relying on low wholesale prices.

AER interpretation of materiality

A number of retailers raised concerns about the transparency of our criteria for assessing costs under the DMO retail cost step change framework. Key comments included:

- the AER has not defined or set quantifiable criteria about what constitute material costs under the framework. Other frameworks, including the AER's network cost pass-through framework, set such criteria, and the DMO framework should also include a criteria for the retail component[72]
- the AER's decision making is subjective and lacks transparency, which is eroding confidence the DMO will achieve its policy intent.[73]

Final Determination

Analysis of retailer cost information

A small number of retailers provided information about additional costs. This information included:

- *COVID-19* – We received two confidential submissions on these costs. We also considered publicly available information. These costs are discussed in a separate COVID-19 costs section below.
- *Advanced meters* – We received three confidential submissions providing information on the additional costs of advanced meter installations.
- *5MS* – We received two confidential submissions providing estimates of the costs to implement 5MS
- *CDR* – We received one confidential submission estimating costs for CDR in the 2021-22 year. These costs are discussed in a separate CDR and 5MS costs section below.
- Additionally, we received one confidential submission providing a combined estimate that included COVID-19, advanced meters, DMO 2 network cost under-estimation and other costs the submitter considered should be accounted for.

We have considered all the information provided. Taken at face value, the claimed total cost increases fall in a range:

- $22 to $45 per residential customer, depending on region
- $22 to $57 per small business customer.

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72 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.3–4.

73 AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1–2.

The limited nature of the data meant we could not estimate a total cost increase that we were confident would be representative of most retailers, and hence would be suitable as a reasonable estimate for the purposes of the step change framework.

While we were not able to estimate a total figure, in light of the new information we have sought to ‘stress test’ the ability of the DMO price to meet the policy objectives, given retailers’ concerns about the materiality of combined retail costs.

For the purposes of this stress test, we have used a nominal figure of $35. We have used this figure as a likely upper end of the range, based on the information provided.

The figure should not be taken to represent an estimated retailer cost increase. Our analysis, using the nominal $35 step change, is set out below.

Median market offer analysis

We acknowledge retailer concerns that the cumulative impact of retail cost increases may jeopardise the DMO objectives. Ensuring the DMO price balances the objectives is our primary goal in setting the price.

Our approach to testing this has been to consider the median market offer price as a reasonable indicator of an efficient price in each region. The gap between the median and DMO has therefore been an indicator of how much margin retailers have above the point where they can recover their costs to serve.

We are mindful that it may be influenced by retailers’ pricing strategies. Our DMO 3 Position Paper noted that the median offer may have been driven lower in 2020 by smaller retailers that are capturing market share and relying on low wholesale prices.

To assess whether the Final DMO price has met the policy objectives, we have analysed it in relation to median market offer. As noted, we have also ‘stress tested’ the DMO price using the nominal $35 cost discussed above.

Tables 7 to 9 below show the median prices, including the impact of the $35 on this difference.

We note this analysis compares prices based on offers from March 2021 with forecast DMO prices for 2021-22. Our expectation is that retail prices will decrease when retailers implement price changes in July 2021 that reflect lower wholesale prices for the coming year.

Table 7: DMO 3/median gap, less $35 nominal step change, residential

	Ausgrid	Endeavour	Essential	Energex	SAPN
MMO-DMO gap	$200	$221	$315	$200	$122
MMO-DMO gap – less $35	$165	$186	$280	$165	$87

Table 8: DMO 3/median gap, less $35 nominal step change, residential CL

	Ausgrid	Endeavour	Essential	Energex	SAPN
MMO-DMO gap	$260	$259	$341	$229	$92
MMO-DMO gap – less $35	$225	$224	$306	$194	$57

Table 9: DMO 3/median gap, less $35 nominal step change, small business

	Ausgrid	Endeavour	Essential	Energex	SAPN
MMO-DMO difference	$1,337	$612	$1,282	$655	$922
MMO-DMO difference – less $35	$1,302	$577	$1,247	$620	$887

The analysis above indicates, even accounting for a hypothetical $35 increase, the DMO 3 price meets the policy objectives.

DMO objective – Retailers can recover efficient costs

Based on our analysis above, and our assumption that the median is a reasonable proxy for a retailer’s efficient costs, we are satisfied the DMO price is sufficiently above the level where retailers can recover efficient costs, as well as a $35 increase in retail costs. We have undertaken further indicative cost stack analysis below, to cross-check this conclusion.

DMO objective – Retailers can make a reasonable profit

We have considered the DMO gap above the median to be an indicator of how much headroom and retail margin is available to retailers. Our analysis indicates:

- The gap is largest for small business customers, and suggests a margin ranging from around 10 per cent above the level of efficient cost recovery (Endeavour) to 19 per cent (Ausgrid)
- For residential customers without CL, the gap suggests a retail margin ranging from around 5 per cent (SAPN) to 15 per cent (Essential)
- For residential flat customers with CL, the gap suggests a margin ranging from around 3 per cent (SAPN) to 14 per cent (Essential).

Our ‘stress test’ analysis indicates that without allowance for a $35 step change costs, retailers would continue to recover margins that are above the pre-DMO margins achieved in the competitive markets estimated by the ACCC in its reports covering 2017-2019.

Tables 10 and 11 below compare gap between the DMO and median offer (expressed as a nominal percentage margin) to the ACCC’s pre-DMO margin analysis.

Table 10: DMO 3/median offer gap – comparison with ACCC retail margins, residential

Region	DMO 3/MMO gap, inc. nominal $35 step change - Residential	DMO 3/MMO gap inc. nominal $35 step change - Residential w/CL	Retailer margins 2018-19 (ACCC November 2019 Report)	Retailer margins 2017-18 (ACCC Retail Electricity Price Inquiry)
Ausgrid	11.8%	11.7%	5.1%	9.9%
Endeavour	11.5%	11.1%	5.1%	9.9%
Essential	14.7%	13.5%	5.1%	9.9%
Energex	11.4%	11.2%	1.2%	2.7%
SAPN	5.1%	2.7%	1.1%	4.1%

Table 11: DMO 3/median offer gap – comparison with ACCC retail margins, small business

Region	DMO 3/MMO gap, inc. nominal $35 step change – Small Business	Retailer margins 2018-19 (ACCC November 2019 Report)	Retailer margins 2017-18 (ACCC Retail Electricity Price Inquiry)
Ausgrid	18.9%	8.2%	8.3%
Endeavour	10.1%	8.2%	8.3%
Essential	16.0%	8.2%	8.3%
Energex	11.2%	8.2%	8.3%
SAPN	11.0%	8.2%	8.3%

Source: AER and ACCC analysis, ACCC analysis does not disaggregate NSW residential customer margins beyond jurisdiction, and does not disaggregate small business margins.

We note that some regulators in non-DMO jurisdictions have set allowances for a reasonable retail margin as part of their retail price setting. The ACT's Independent Competition and Regulatory Commission (ICRC) allows a margin of 5.3 per cent. The Essential Services Commission of Victoria (ESCV) and Queensland Competition Authority (QCA) allow a 5.7 per cent margin.[74]

Our analysis suggests the DMO price is high enough that retailers can recover these benchmark 'reasonable retail margins' as defined by these jurisdictional regulators, with the exception of residential customers in the SAPN region.

The ACCC information indicates the margins under the DMO are reasonable for these customers, based on pre-DMO margins.

DMO objective – There are incentives for retailers to compete, innovate and invest

Retailers, including retailers with few or no standing offer customers, have expressed concern that not accounting for cost increases in the DMO price is risking the

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[74] ICRC: https://www.icrc.act.gov.au/__data/assets/pdf_file/0003/1372773/Report-6-of-2019-Electricity-Price-Reset-2019-20.pdf#page=30; ESCV: https://www.esc.vic.gov.au/sites/default/files/documents/Victorian%20Default%20Offer%20to%20apply%20from%201%20January%202020%20-%20For%20web%20publishing.pdf#page=60; QCA: https://www.qca.org.au/wp-content/uploads/2019/05/30575_QCA-Final-Determination-Regulated-electricity-prices-for-2016-17-3.pdf. See page 24.

competition element of the DMO policy. A key concern is that requiring them to absorb cost increases erodes the profitability of offers over time.

Our analysis suggests that, other than for residential customers in South Australia, retail margins greater than 10 per cent provide retailers with significant flexibility to offer discounts below DMO price without affecting their cost recovery.

While this ability is more constrained for residential customers in South Australia, we have not seen evidence that the introduction of the DMO price is impacting competition in South Australia, or that retailers have been discouraged from entering the market. We note:

- *Competition and innovation are active in South Australia*
    - Our most recent market analysis of EME data for March 2021 has found that retailers are continuing to compete for market share, with discounts below the DMO/reference price up to 20 per cent.
    - Retailers are increasingly competing on innovative non-price aspects such as customer service, bundling electricity with mobile phone or internet plans, or offering online portals and apps to monitor usage.
- *Retailers continue to enter the South Australian market*
    - The number of brands retailing to small customer increased from 21 in June 2019, to 28 in March 2021.[75]
- *Customers continue to engage in the South Australian market*
    - Rates of customers switching between retailers remain steady and are above those in Queensland and ACT.[76]
    - South Australia continues to have the lowest proportion of customers on standing offer contracts in the National Energy Retail Law regions.[77] We note this has increased by around 0.7 per cent over the last quarter after decreasing and remaining flat for several quarters. We will continue to monitor this issue.

DMO objective – consumers have incentives to engage in the market

Retailers have highlighted that if the DMO is set too low they will not be able to advertise market offers with significant headline discounts off the reference DMO price, meaning customers will be less motivated to switch from their current offers to the latest market offers.

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75 AER, Analysis of Energy Made Easy data of retailer offers available on 30 June 2019 and 22 March 2021 in SAPN.

76 AER, Analysis of AEMO Retail Transfer Statistical Data, available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/metering-data/real-transfer-statistical-data.

77 AER, Analysis of Retailer Performance Reporting data,

We consider that the DMO 3 prices will not dis-incentivise customers from engaging in the market. We have found that even customers on lower price offers can continue to save significant amounts of money by switching to lower price offers (as of March 2021).

When switching from the DMO 3 price to the lowest market offer, residential customers would stand to save:

- In New South Wales, between $427 (Ausgrid) and $557 (Essential)
- In South East Queensland, $454
- In South Australia, $340.

When switching from the DMO 3 price to the lowest market offer, small business customers would stand to save:

- In New South Wales, between $1,253 (Endeavour) and $2,224 (Ausgrid)
- In South East Queensland, $1,591
- In South Australia, $2,624.

Customers on the median market offer also stand to make substantial savings by switching to the lowest market offer, suggesting even customers on moderately priced plans have further incentives to shop around.

When switching from the median market offer price to the lowest market offer, residential customers would stand to save:

- In New South Wales, between $227 (Ausgrid) and $241(Essential)
- In South East Queensland, $254
- In South Australia, $217.

Small business customers would stand to save:

- In New South Wales, between $641 (Endeavour) and $943 (Essential)
- In South East Queensland, $935
- In South Australia, $1,703.

Discounts below the DMO price

We have found that the lowest market offers would continue to have significant headline discounts off the DMO 3 reference price.

Table 12 below compares the advertised discount of the lowest market offer when DMO 2 was introduced to the possible advertised discount relative to the DMO 3 for the lowest market offer in March 2021. We observe the lowest price market offer continues to be a significant percentage below the DMO 3 reference price.

This suggests retailers pricing aggressively to gain market share and advertising significant discounts of 20 to 30 per cent off the reference price could continue this strategy when the DMO 3 price comes into effect on 1 July 2021.

Table 12: Largest advertised discount below DMO price, July 2020 and March 2021

Customer Type	Region	Discount below DMO 2 for lowest market offer July 2020	Discount below DMO 3 for lowest market offer March 2021
Residential Flat Rate without CL	Ausgrid	27%	31%
	Endeavour	28%	28%
	Essential	26%	29%
	Energex	27%	31%
	SAPN	23%	20%
Residential Flat Rate with CL	Ausgrid	26%	26%
	Endeavour	26%	25%
	Essential	24%	26%
	Energex	26%	29%
	SAPN	22%	15%
Small Business Flat Rate	Ausgrid	35%	32%
	Endeavour	26%	22%
	Essential	26%	29%
	Energex	32%	29%
	SAPN	28%	33%

Median cross-check analysis

Noting EnergyAustralia's view that our analysis does not consider the impact of the cumulative cost increase on retailers' margins, we have undertaken analysis to cross-check our median analysis against the DMO cost stack, incorporating an indicative retail cost component.

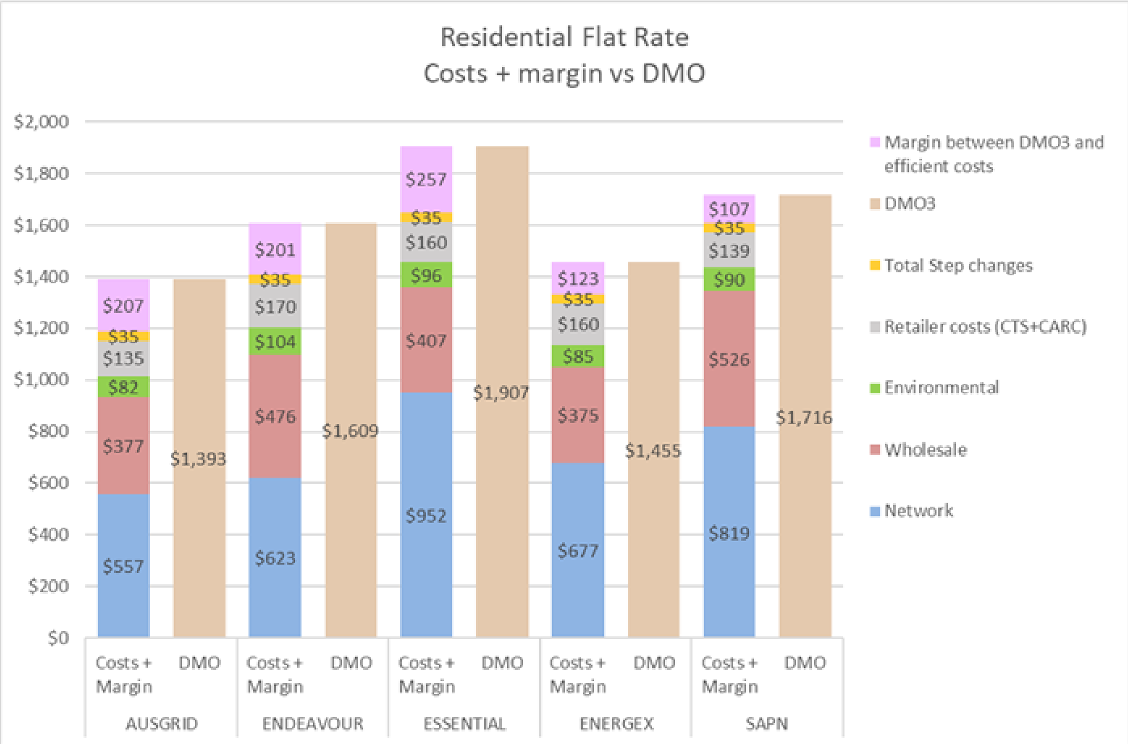
The indicative analysis, shown in Figures 5 to 7 below, is based on indicative cost estimates and DMO 3 forecasts, and therefore does not rely on any median estimates.

This analysis uses the following assumptions about retailer costs:

- DMO 3 final wholesale, network and environment cost forecasts
- The nominal $35 step change for the purposes of stress-testing the policy objectives
- For residential retail operating costs:
  - costs of $135 to $170 (including GST), depending on region, based on ACCC published retail market analysis.[78]
- For small business retail operating costs:
  - an average of $320 ($352 including GST) per small business customer, based on ACCC retail costs of 1.6 c/kWh for a 20,000 kWh small business.[79]

Figures 5 to 7 show indicative DMO cost stacks for each customer type and region.

Figure 5: DMO cost stack including indicative retail costs, residential



78 ACCC, *Inquiry into the National Electricity Market - November 2019 report*, Appendix E, Figure 2.6.

79 ACCC, *Inquiry into the National Electricity Market – November 2019 report*, Appendix E, Figure 2.7.

Figure 6: DMO cost stack, including indicative retail costs, residential CL

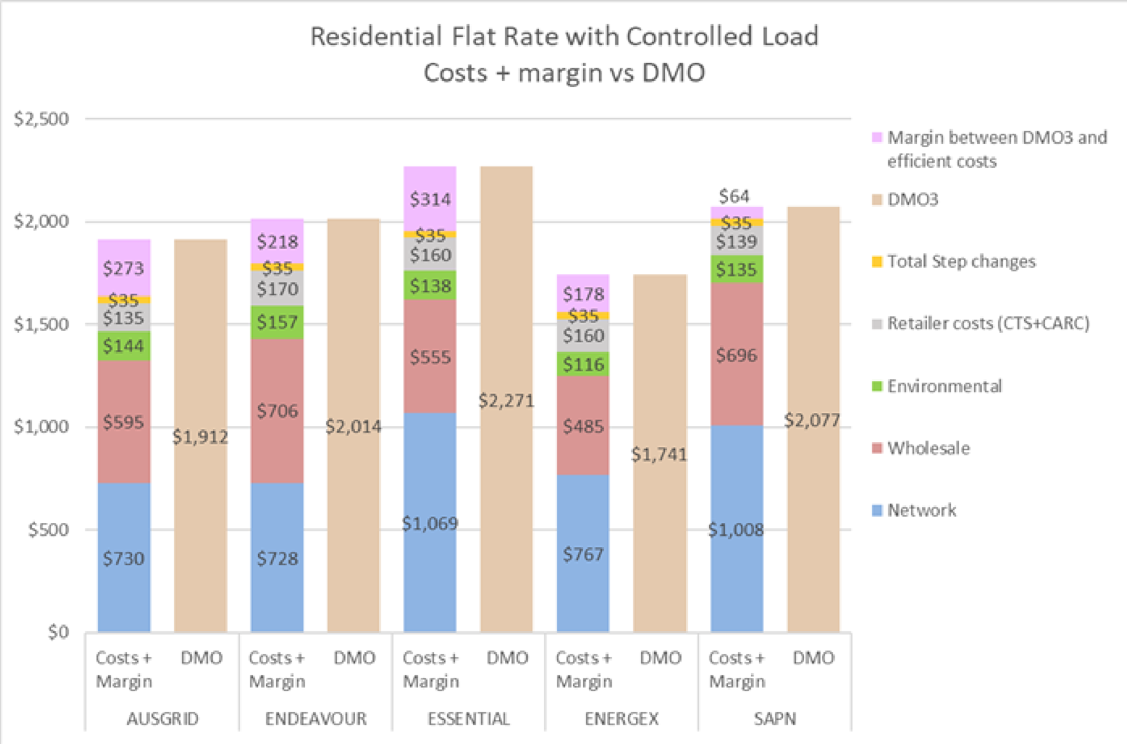
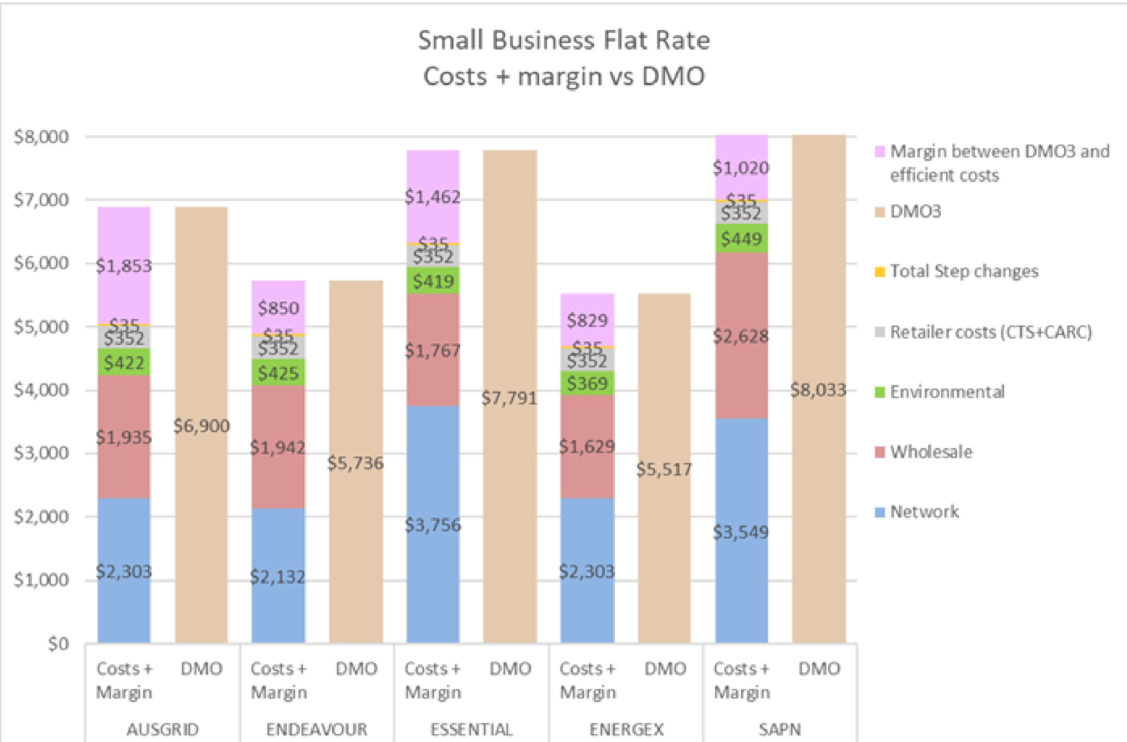


Figure 7: DMO cost stack, including indicative retail costs, small business



For residential customers, the nominal margins above the level of efficient costs we observe from this analysis are broadly consistent with those from our median offer analysis. For example, the suggested margins are within +/- 3 per cent of the gap between the DMO and MMO.

For small business customers, the nominal margins above the level of efficient costs and nominal retail step change costs are higher than in our median offer analysis. This is because our analysis suggests that the MMO price for small businesses already includes margin above efficient costs and nominal retail step change, ranging from 1.7 to 8 per cent depending on region.

While emphasising its indicative nature, we consider the above analysis supports our view that the median market offer is a reasonable indicator for assessing the DMO price against the policy objectives.

Conclusion

We acknowledge retailers' comments and concerns about the step change framework and the transparency in our Draft Determination that forecast increases in retailer costs were not material.

We regard a material change is one that would prevent the DMO price from achieving all the policy objectives.

Based on the evidence above, we are satisfied that the cumulative retail cost increases are not sufficiently material to warrant adjustment to the DMO price.

We note retailers' preference for a framework with quantifiable criteria. We will consider these issues as part of our methodology review.

COVID-19 costs

COVID-19 and measures to restrict its transmission have had impacts on the Australian economy, including businesses and households. Submissions to our DMO 2 COVID-19 consultation[80] considered the major categories of retail costs that would likely increase are:

- bad debt – debt a retailer 'writes off' as never recovering
- doubtful debts as a result of more customers experiencing financial vulnerability. This includes additional short-term debt carrying costs due to more customers accessing hardship programs and extended payment plans
- cost to serve as a result of requirements for staff to work from home, closure of international call centres, which have required some retailers to bolster onshore

[80] AER, *submissions to impact of COVID-19 on the determination of the Default Market Offer*, April 2020: https://www.aer.gov.au/retail-markets/guidelines-reviews/retail-electricity-prices-review-determination-of-default-market-offer-prices-2020-21/draft-decision.

capabilities, and increases in the volume and complexity of communication with customers, due to an increase in calls about payment difficulty, hardship and/or broken payment plans.

Draft Determination

Our Draft Determination noted that bad debt costs and any cost to serve increases due to COVID-19 in the DMO 3 period were not sufficiently material to warrant an adjustment under our step change framework.

This decision was based on the publicly available information provided at the time that estimated bad debt increases range from around $4 to $10 per customer for 2020-21.

While we noted that while we were open to considering further information, the cost increases indicated that while likely to be higher than the CPI rate of change, they were not large enough that retailers' abilities to recover\ costs and make a reasonable profit would be jeopardised if we did not make a specific adjustment.

We noted the ESCV's 2021 Victorian Default Market Offer final decision to include a $6 per customer allowance for COVID-19 debt impacts, but highlighted:

- unlike the VDO, the DMO is not a 'bottom up' cost stack that estimates the efficient costs and margins for retailers. The VDO methodology aims to account for all efficient costs faced by retailers and pass through these costs, including minor costs
- the DMO has a different policy objective and uses a different methodology that includes a residual component to ensure customers on standing offers are not being charged unjustifiably high prices, while allowing retailers to recover their costs. Because the DMO 3 is well above efficient costs, we have a high threshold for passing through additional costs.

Stakeholder submissions

Retailers did not support our Draft Determination position to not include an allowance in the DMO 3 price for COVID-19 related costs, citing concerns the cumulative impact of costs, including those attributable to COVID-19, will reduce retailer margins.[81] We discussed these in the previous section.

The AEC considered the determination not to account for COVID-19 costs is short sighted, because if not including these costs is later found to be not in the interests of consumers, retailers will have already been adversely affected.[82]

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81 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p1–2; Alinta Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1; AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1; Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p.1; AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1; Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1; EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1–7.

82 AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1.

AGL referred to a provision of $35 million for bad and doubtful debt stated in its publicly available half yearly report.[83]

Alinta Energy encouraged us to give further consideration to including COVID-19 related costs in the DMO 3 price, including for additional operating costs, bad and doubtful debt costs, and the increased costs of managing customers in hardship.[84]

Origin Energy re-stated its view that we should adopt an alternative basis for including costs based on whether they are 'controllable' or 'uncontrollable', and that we should pass through uncontrollable costs directly in the DMO price.[85] It suggested the increase in COVID-19 debt should be regarded as uncontrollable in as far as it has been influenced by the AER's Statement of Expectations (SOE). Origin Energy suggested the SOE has contributed to increasing customer debt levels by limiting retailers' abilities to issue disconnection warning notices.[86]

Simply Energy considered the risk that COVID-19 continues to disrupt economic activity remains high for 2021. Simply Energy also noted that worsening economic conditions correlate with higher retailer bad debt levels and reductions in retailer margins.[87]

Consumer representatives supported our position to not adjust the DMO price to account for COVID-19 cost increases. PIAC commented it 'strongly supports the AER's decision not to make specific adjustments to the DMO in response to COVID-19'.[88] It considered any adjustment to the DMO price is not appropriate under the current methodology because:

- the DMO is set above efficient costs to serve, 'including a profit margin and significant additional headroom'
- residual costs, including retailer costs are adjusted by CPI annually
- the DMO only relates to standing offers, and retailers can adjust market offer prices above or below the DMO as preferred.[89]

Final Determination

For the Final Determination, we have considered the most recent publicly available costs and information provided by retailers in their submissions.

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83 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.4.

84 Alinta Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1.

85 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1.

86 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.4.

87 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1–2.

88 PIAC, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1.

89 PIAC, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1.

Since publishing our Draft Determination, AGL, Origin Energy and EnergyAustralia have published updated information in their financial reports ending 31 December 2020.[90]

- AGL has reduced its provisioning for bad and doubtful debts due to COVID-19 in the 2020-21 year, from approximately $10 to $9 per customer
- Origin Energy maintained its COVID-19 provisioning from the 2019-20 year at approximately $10 per customer
- EnergyAustralia reported an increase of about $11 per customer in bad and doubtful debts from 2019 to 2020.

A small number of retailers provided confidential information on their forecasts for the 2021-22 year.

The range of these forecasts reflects the uncertainty about the extent of COVID-19 impacts across the DMO 3 period, due to factors such as decreasing unemployment[91], signs of economic recovery, and the removal of the JobKeeper subsidy.

We note some retailers have revised their provisions for bad and doubtful debt due to COVID-19 downwards for 2020-21, with one retailer forecasting bad and doubtful debt costs due to COVID-19 in the DMO 3 period being 75 per cent lower than in the previous year.

Based on this information, we estimated an average cost per customer increase of $9 per customer for 2021-22.

As discussed above, we are satisfied retailers will be able to recover their efficient costs and make a reasonable profit if these forecast costs eventuate, and that an allowance for these step change costs is not required.

Regarding Origin Energy's point about the impact of the SOE, we acknowledge the moratorium on commencing collection action may have had some impact on retailer debt levels above what may have occurred had there been no restriction on disconnection activity.

However, this does not alter our assessment of COVID-19 related debt, and other retail cost increases are not material enough to warrant an adjustment to the DMO under our step change framework.

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90 AGL and Origin report on a financial year basis and have published half year 2020-21 results in February 2021. EnergyAustralia's parent company, CLP Group, reports on a calendar year basis and published 2020 results in February 2021.

91 For example, recent economic data indicating reductions in the unemployment rate in February 2021 to 5.8 per cent from ABS, *Monthly labour force survey*, February 2021: https://www.abs.gov.au/statistics/labour/employment-and-unemployment/labour-force-australia/latest-release

Consumer Data Right Reforms and 5 Minute Settlement

Draft Determination

CDR reforms are being rolled out to consumers in the electricity sector, facilitating easier consumer access to their metering and other data.

Retailers will need to develop and maintain systems that ensure they can comply with the new requirements.

We expect the new CDR obligations[92] for the energy sector will come into effect during the DMO 3 period.

In the Draft Determination we acknowledged the costs associated with CDR are unavoidable and an exogenous change in a retailer's operating environment. However, we had not received information that would enable us to estimate retailers' costs for CDR in 2021-22.

In response to our request for information about the cost of implementing 5MS reforms, retailers did not demonstrate these costs are significant enough to warrant inclusion as a step change. We did not make a step change in DMO 2 for 5MS or any other market reforms.[93] We considered the majority of 5MS costs will be incurred prior to the DMO 3 period as these system changes need to be in place in preparation for 1 October 2021.[94]

We requested further evidence provided by retailers prior to the Final Determination.

Stakeholder submissions

EnergyAustralia submitted that 5MS and other costs were never compensated for under DMO 2. It acknowledges that the AER had judged these items as being immaterial at the time. EnergyAustralia queried the AER's justification that the DMO is forward-looking and it is now only seeking to assess costs incurred over 2021-22.[95]

Momentum submitted that often retailers are required to amend and upgrade their systems and processes for regulatory changes. These changes may not benefit retailers in revenue or efficiency gains. For example, changes required for 5-minute settlements imposed considerable cost on retailers in amending their systems and processes to ensure compliance and will primarily benefit electricity retailers.[96]

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92 *Consumer Data Right (Energy Sector) Designation 2020*.

93 AER, *Default Market Offer Prices 2020-21*, Final Determination, p. 48.

94 Essential Services Commission Victoria, *Default Offer 2021 Final Decision*, 27 November 2020, p. 33.

95 EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 8.

96 Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p. 3–4.

EnergyAustralia and Momentum both provided cost estimates in confidential submissions.[97] We have considered this information in our assessment of cumulative cost impacts.

Final Determination

We have considered the reforms and regulatory changes affecting retailer's cost to serve, in particular 5MS and CDR. As discussed above, we have considered the cumulative effect of the changes in all retailer costs. We have determined these costs are not significant enough to warrant inclusion as a step change for DMO 3.

Productivity

Draft Determination

We considered a number of different sources of published information in determining not to apply a productivity adjustment to the DMO.

Publicly available ACCC industry data[98] and retailer annual reports did not provide enough detail about capital and other costs we would need in order to understand whether cost reductions were due to productivity increases.

The ABS productivity data suggests productivity growth in the electricity retail sector is not materially different from the overall economy. A productivity factor based on this data would be zero, that is, it would have no effect on the DMO price.

Stakeholder submissions

Retailers generally supported our Draft Determination that we will not apply a productivity adjustment to DMO 3.

AGL considered that any assessment of productivity adjustments is inconsistent with the top-down methodology of the current framework. It also cites the complication of the current operating environment due to COVID-19 and the integration of several business acquisitions.[99] Alinta Energy submitted that 'any measure of energy sector productivity will be less significant than the step-change, industry-wide impacts from the COVID pandemic.' It also lists other regulatory changes which will generate costs for retailers during the DMO 3 period.[100]

Simply Energy submitted that a productivity factor should only be considered if we were to use a more representative estimate of retail costs in the DMO price

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97 EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 13–1; Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p. 4.

98 The ACCC's Electricity Monitoring Inquiry publishes information about retailers' costs. See https://www.accc.gov.au/regulated-infrastructure/energy/electricity-market-monitoring-2018-2025

99 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p. 4.

100 Alinta Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 1–2.

determinations. It noted that ‘the DMO should broadly follow changes in the costs of providing retail energy services so that the headroom within the DMO remains at a broadly consistent level over time.’ Therefore, the AER could re-base the DMO stack if the DMO becomes too high or too low relative to median market offers.[101]

PIAC was the only consumer stakeholder to make a submission on this matter.

It considered a productivity adjustment should be applied to the DMO. PIAC submitted it has ‘observed in the course of each DMO determination process, a “bottom up” or cost-based approach to calculating the DMO would make all calculations and decisions transparent.’ This would allow for calculation of cost components and the current lack of cost transparency.[102]

Final Determination

Having considered stakeholder submissions and available information,[103] our Final Determination position is unchanged from that set out in the Draft Determination. In summary, the available information suggests productivity for the electricity retail sector has not increased above that of the overall economy.

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101 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 3.

102 PIAC, *Submission to DMO 3 Draft Determination*, 18 March 2021, pp. 1–2.

103 AER, *Draft Determination, Default market offer prices 2021–22*, 17 February 2021, pp. 67–72.

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

This chapter sets out our methodology for determining the DMO model annual usage for 2021-22, including how we have considered TOU and solar tariff customers under the single DMO price.

4.1 Model annual usage

Draft Determination

Our Draft Determination was to retain the annual usage amounts for residential and small business customers from DMO 2. While we noted customer usage may change over time, we were satisfied our usage amounts remain broadly representative of customers usage. Stakeholders generally supported this approach as providing consistency and comparability.

We considered the effect of COVID-19 on energy consumption, but noted that:

- limited data availability meant we could not yet gauge this change over a year
- any changes would need to be sufficiently large that the amounts were no longer representative of customer usage, and that the benefits of changing usage amounts need to outweigh the benefits of being able to compare offers year-to-year from retaining the same usage amounts.

For the timing and pattern of supply, our Draft Determination was:

- for all customers, assume the same usage amount every day (with no variation for weekday, weekend or season)
- for residential customers with CL, apply the same proportional allocations of annual CL usage across multiple CLs as in previous determinations
- for TOU tariff customers, assume the usage across each day follows a set pattern, expressed in the form of a simple 24-hour profile
- for customers with a retail tariff including the SAPN TOU CL network tariff, introduce a separate TOU CL usage profile to provide retailers with the flexibility to identify their own tariff windows.

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

The Draft Determination updated the single day usage profile for TOU tariffs first introduced in DMO 2, using AEMO interval meter data for each region, and specified usage for every 30-minute interval over a 24-hour period. Stakeholders generally supported a simple profile as being more straightforward to implement.

For the usage profiles, we determined to use usage data taken from the three years prior to March 2020. We acknowledged that COVID-19 is likely to have impacted usage patterns since then and we said if longer term changes in usage are observed in the approved annual prices, we may consider changing the annual usage amounts in future determinations. However, we would need to be satisfied the changes are sufficiently large that the usage amounts adopted for the DMO are no longer broadly representative of customer usage. Also, we would need to ensure the benefits to customers of changing the usage amounts outweigh the benefits of being able to compare offers year-to-year from retaining the same usage amounts.

Stakeholder Submissions

Stakeholders did not comment on our Draft Determination to retain the same annual usage amounts for residential and small business customers from DMO 2, and to retain the same timing and pattern of supply arrangements for DMO 2.

Simply Energy supported our Draft Determination approach to update the TOU hourly usage profile with recent data and retain a single day profile, considering that a more granular profile would not significantly improve consumers' abilities to compare the offers.[105]

In follow-up correspondence on its submission, EnergyAustralia noted the TOU daily usage profile did not add to the specified annual usage figure.

No other stakeholders provided comments in relation to the TOU usage profiles. Similarly, stakeholders did not comment on our Draft Determination to establish an hourly profile for the SAPN TOU CL tariff.

Origin Energy queried why the amount of the residual component for a SAPN flat rate customer consuming 4 MWh annually is higher than the residual component of a SAPN flat rate customer with CL consuming 6 MWh annually. Origin suggested a customer consuming more energy would be expected to pay a higher residual amount in dollar terms.[106]

Final Determination

Our Final Determination is to retain the annual usage amounts for residential and small business customers from DMO 2 as set out in our Draft Determination.

105 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.3.

106 Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 5.

- For all customers, we assume the same usage amount every day (with no variation for weekday, weekend or season).
- For residential customers with CL, we apply the same proportional allocations of annual CL usage across multiple CLs as in previous determinations.
- For TOU tariff customers, we assume the usage across each day follows a set pattern, expressed in the form of a simple 24-hour profile.

We will re-consider annual usage assumptions as part of our DMO 2022-23 (DMO 4) methodology review.

Our Final Determination position is to update TOU hourly usage profiles with interval meter data provided by AEMO.

Based on EnergyAustralia’s feedback, we have specified the TOU increments to four decimal places so these sum to the annual usage figure.

Our Final Determination is also to introduce the SAPN TOU CL hourly usage profile proposed in the Draft Determination.

In response to Origin Energy’s comment regarding the different residual amounts obtained from the SAPN residential and SAPN residential CL tariffs, we note this results from how the residual was calculated for DMO 1.

The residual component was originally calculated as the remainder after the wholesale, network and environmental costs were subtracted from the DMO 1 price.

For residential CL customers in the SAPN region, the network and wholesale cost components accounted for a higher proportion of the overall DMO price, resulting in a lower residual proportion.

- For non-CL customers, the wholesale component accounted for 37 per cent of the DMO price, while network costs accounted for 43 per cent. The residual component was $283, or 15 per cent of the total cost.
- For CL customers, the wholesale component accounted for 40 per cent of the DMO price, while network costs accounted for 44 per cent. The residual component was $247, or 10 per cent of the total cost.

The annual usage amounts, and all TOU usage profiles are set out in the Legislative Instrument at Appendix E.

4.2 Costs to serve TOU and solar customers

Draft Determination

We considered the additional costs to serve TOU customers, including advanced meters costs.

We noted that in relation to advanced meter costs, retailers’ comments fell broadly into two categories. Tier one retailers were concerned about the revenue impact for standing offer customers with advanced meters. Tier two retailers generally have fewer standing offer customers, and their concerns related rather to the function of the DMO as a de facto price cap on market offer prices, despite there being no obligation to limit market offer prices to the price cap. They were concerned that in absorbing advanced meter costs, they would need to offer lower discounts, or if offering the same discounts, they would obtain less revenue.

For our Draft Determination we proposed not to make a specific allowance in the DMO price for these costs. Our key reasons were:

- analysis of advanced meter customer numbers and tariff types that we requested from retailers confirmed the proportion of customers with advanced meters is low compared to the number of customers with accumulation meters ─ on average 18 per cent of residential, and 10 per cent of small business customers have advanced meters
- were we to account for advanced meter costs in the DMO price, we noted that 80 to 90 per cent of standing offer customers would face higher DMO prices to compensate retailers for costs not related to them. In our view, this would not be an equitable outcome
- we were also satisfied the DMO price is high enough above retailers' efficient costs that retailers can currently absorb the higher costs to serve advanced meter customers without impacting the DMO objectives
- retailers have various options to recover costs from market offer customers─ for example, via an installation fee.

We noted we would continue to monitor our approach to ensure it remained appropriate in future, as smart meters become more prevalent in DMO regions.

Stakeholder Submissions

Corresponding to their comments regarding costs considered under the step change framework, Origin Energy, Momentum Energy, Simply Energy, Alinta Energy, the AEC and EnergyAustralia expressed concern that advanced meter costs incurred by retailers are not provided for in the DMO 3 prices.[107] They argued this cost is material when considered together with the other retailer costs considered under the step change framework. They were concerned that retailer revenue is being reduced by the cumulative impact of costs including for advanced meters, and that a reduction in revenue could harm competition in the longer term, to the detriment of customers.[108]

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[107] Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1–2; Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p.1, 3; Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.3; Alinta Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p. 2; AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1; EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.11.

[108] AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1; Origin Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.1–3; AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.4;

Simply Energy noted if retailers are asked to absorb these costs solely through competitive market offers, this will likely reduce the headroom in the DMO price and reduce the level of discounts available in the market.[109]

The AEC, Momentum Energy and Simply Energy urged us not to hold off making an allowance for advanced meter costs until after we conduct the methodology review later in 2021.[110] For example, the AEC suggested requiring retailers to absorb incremental cost increases 'drive[s] down retailer headroom to an unsustainable level [that] risks impacts on competitive market benefits'.[111] Retailers also suggested as advanced meter take up increases, retailer cost under-recovery will grow.[112]

Origin Energy considered retailers have under-recovered for advanced meter costs for DMO customers.

Momentum Energy noted energy industry expectations that advanced meter take up will enable customers to better manage energy use, but suggested if retailers are not able to recover costs for advanced meter installations, they will be dis-incentivised from voluntarily rolling out advanced meters, and will limit installations to faulty meter and end of life replacements, and customer product incentives like solar installations.[113]

EnergyAustralia noted all customers with advanced meters in the SAPN region will be shifted to TOU network tariffs from mid-2021, acknowledging retailers will be the ones to determine whether and how this is reflected in retail tariffs. EnergyAustralia disagreed that retailers can cover the additional cost to serve advanced meter customers, and considered a cost allowance should be provided in the DMO price.[114]

AGL considered advanced meter costs are likely to be small currently, though are expected to grow in future years as customer take up increases. In contrast to other retailers, it suggested we consider including an advanced meter cost allowance in future DMO determinations.[115]

Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p.3–4; EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.7.

109 Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.2.

110 AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1; Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p.1; Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.3.

111 AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.2.

112 AEC, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.1; Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p.3; Simply Energy, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.3; EnergyAustralia, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.11.

113 Momentum Energy, *Submission to DMO 3 Draft Determination*, 17 March 2021, p.3. We note these types of installations are required by the National Electricity Rules and National Energy Retail Rules, as set out in the AER compliance update on 'Timeframes for installation and repair of meters for small customers': https://www.aer.gov.au/system/files/AER%20Compliance%20update%20-%20metering%20timelines.pdf_0.pdf

114 EnergyAustralia, *Submission to DMO 3 Draft Determination*, 18 March 2021, p.11.

115 AGL, *Submission to DMO 3 Draft Determination,* 18 March 2021, p.4.

Final Determination

As discussed in section 3.3.4, we have considered advanced meter costs together with the other retailer costs identified in retailer submissions, to determine whether the DMO 3 price is high enough above efficient costs to enable retailers to cover these costs.

Having undertaken this analysis we remain of the view that the DMO price is high enough above the level of efficient costs that retailers can currently cover advanced meter cost increases of the level suggested, without jeopardising the policy objectives.

We have considered Momentum Energy's point that a low return on advanced meter customers would be a disincentive to retailers to encourage customer take up of advanced meters outside of specified installation requirements. As discussed in section 3.3.4, our margin analysis indicates the DMO price is well above a reasonable margin in all regions, indicating advanced meter costs, when considered together with other additional retailer costs, for example, relating to COVID-19, are being recovered by retailers.

Our Final Determination is not to adjust the DMO 3 price to account for increased costs to serve Advanced Meter customers.

Given the increasing rate of advanced meter penetration, we will continue to monitor our approach to ensure it remains appropriate to achieving the DMO objectives.

Appendices

Appendix A – List of submitters to the DMO 3 Final Determination

Appendix B – Market offer analysis for each distribution region

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

Appendix D – DMO 2 to DMO 3 price movements

Appendix E – Legislative instrument

Appendix F – Statement of compatibility with human rights

A List of submitters to DMO 3 Draft Determination

1. Australian Energy Council (AEC)
2. AGL
3. Alinta Energy
4. EnergyAustralia
5. Momentum Energy
6. Origin Energy
7. Public Interest Advocacy Centre (PIAC)
8. Queensland Electricity Users Network (QEUN)
9. SA Power Networks (SAPN)
10. Simply Energy

B Market offer analysis for each distribution region

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

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 seven points in time:

- October 2018 – the same data that informed our DMO Final determination. The offers in this dataset preceded the announcement of our DMO
- June 2019 – immediately before the introduction of the DMO
- December 2019 – six months after the introduction of the DMO
- March 2020 – nine months after the introduction of the DMO.
- August 2020 – capturing offers after the second DMO came into effect
- December 2020 – six months after the second DMO came into effect
- March 2021 – nine months after the second DMO came into effect

Figures B.1 to B.15 below show these movements in graph form. These fifteen graphs show the offers from Energy Made Easy (EME) for the three customer types and five distribution regions. To calculate the annual bill amounts from EME data, we used assumptions to allow direct comparison of generally available offers. The list of annual bill calculation assumptions is published in our DMO 2 Final Determination.[116]

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[116] AER, *Final Determination, Default Market Offer Prices 2019-20,* April 2019, Appendix C, p. 69–70.

Changes in market offer prices in Ausgrid's region

Figure B1: Residential flat rate tariff

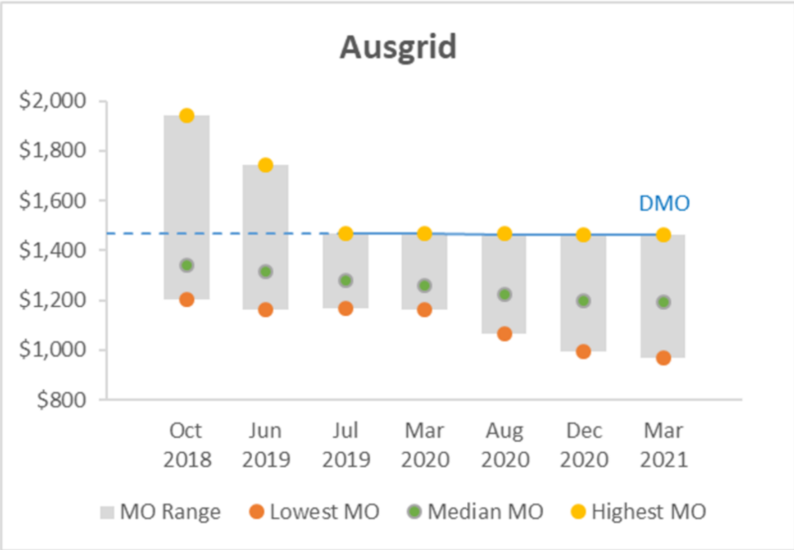


Figure B2: Residential flat rate tariff with controlled load

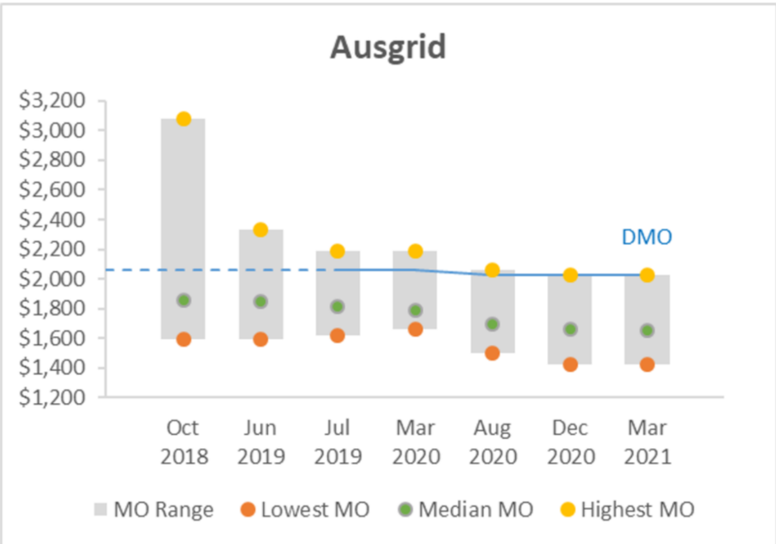
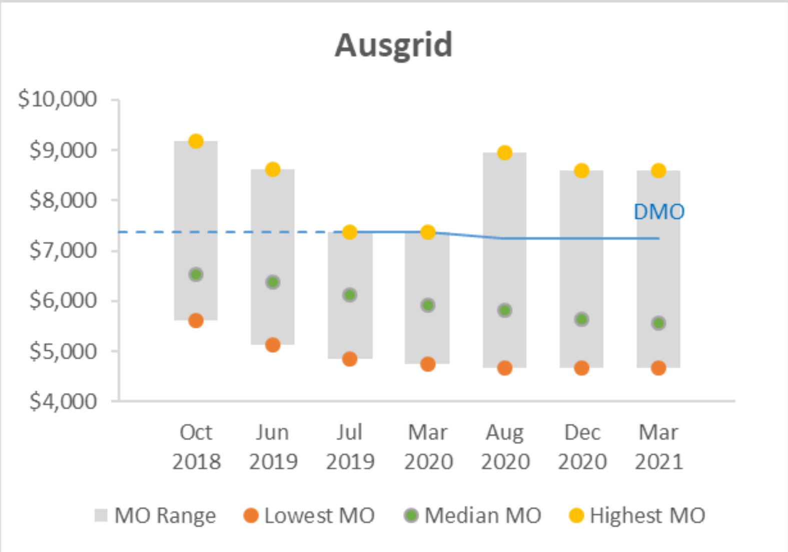


Figure B3: Small business flat rate tariff



Changes in market offer prices in Endeavour Energy's region

Figure B4: Residential flat rate tariff

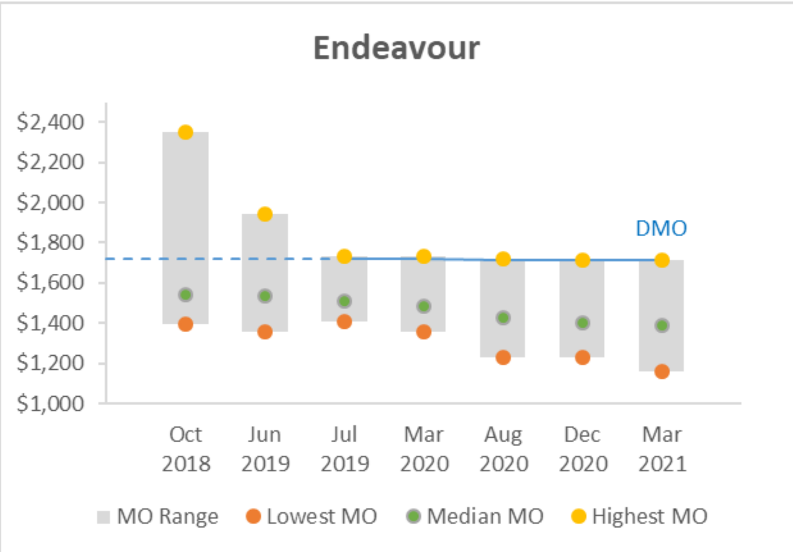


Figure B5: Residential flat rate tariff with controlled load

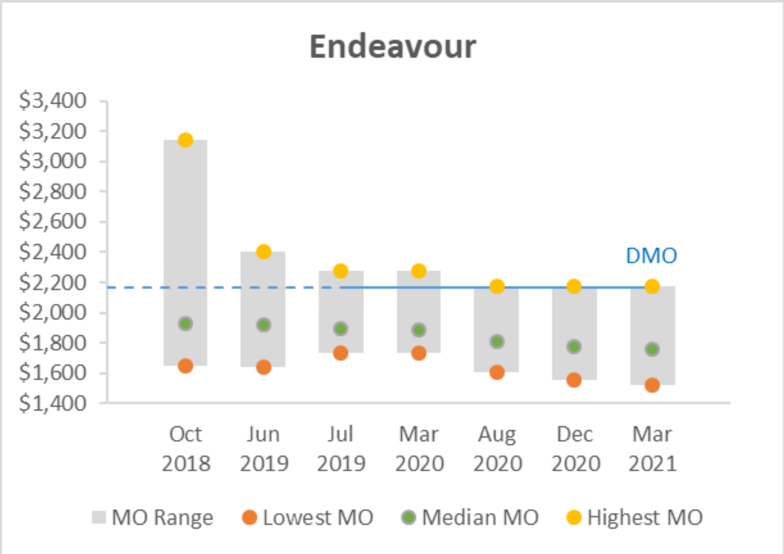
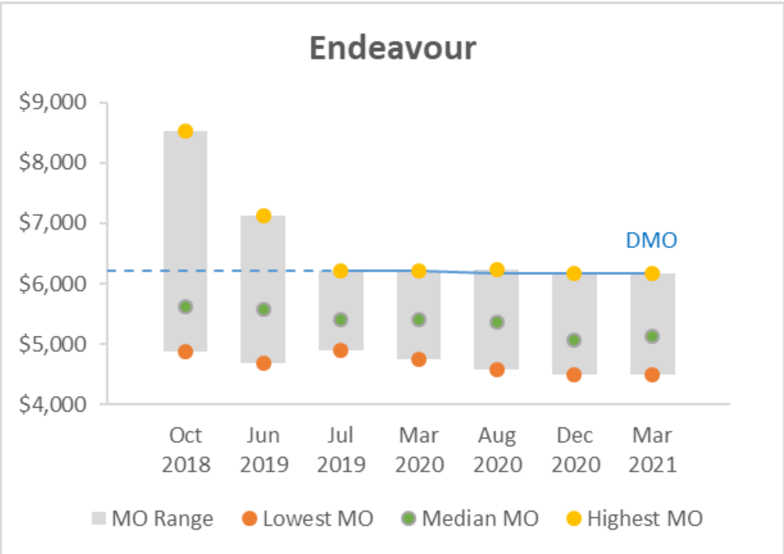


Figure B6: Small business flat rate tariff



Changes in market offer prices in Essential Energy's region

Figure B7: Residential flat rate tariff

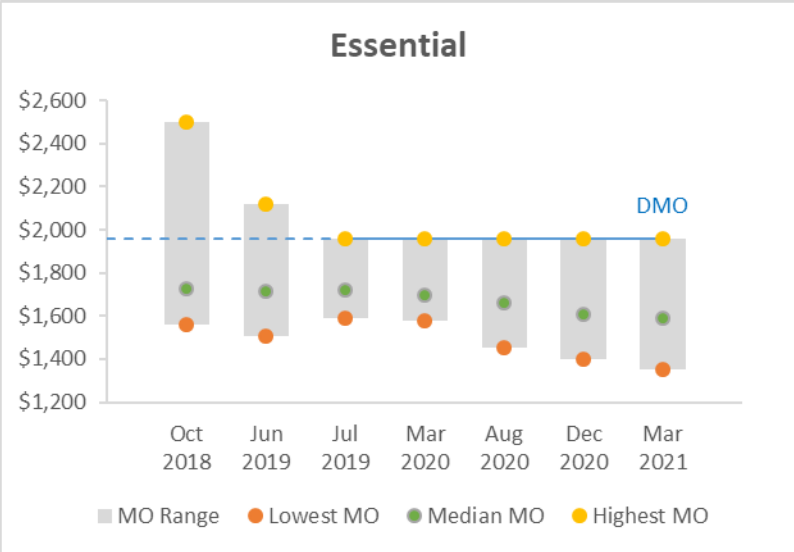


Figure B8: Residential flat rate tariff with controlled load

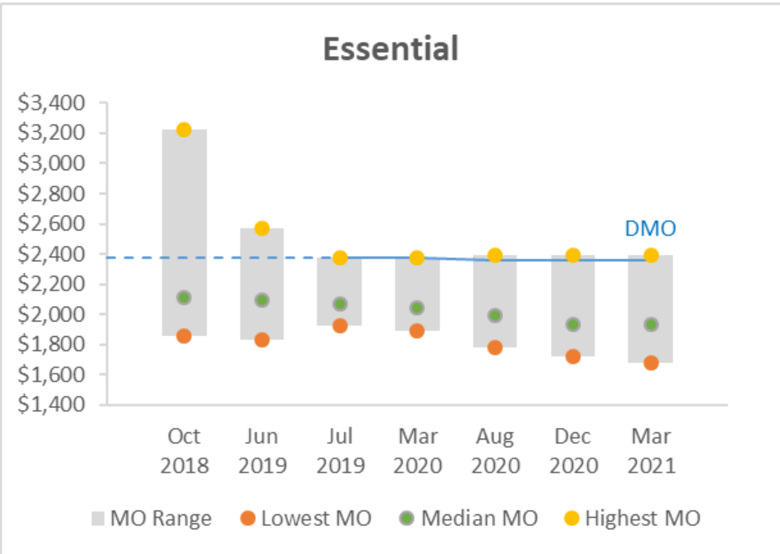
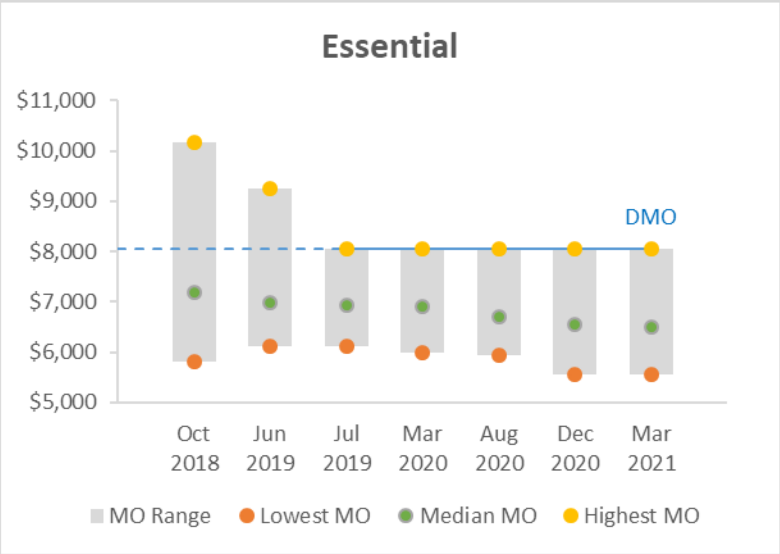


Figure B9: Small business flat rate tariff



Changes in market offer prices in Energex's region

Figure B10: Residential flat rate tariff

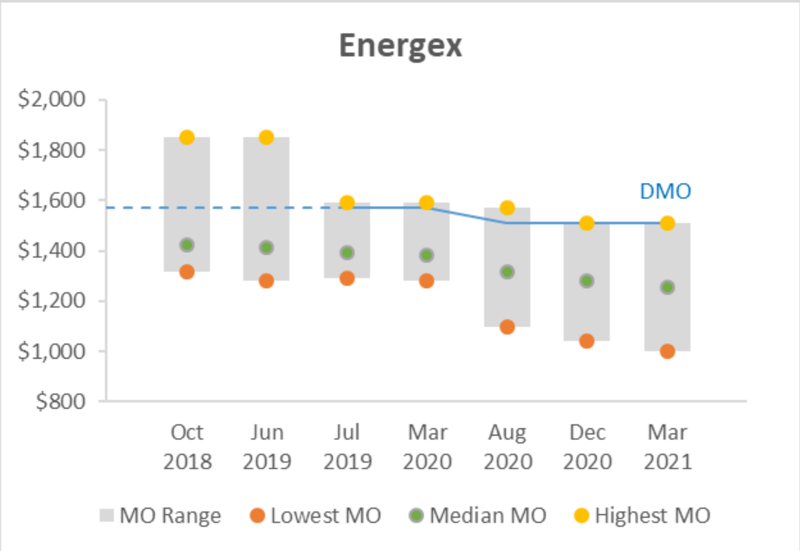


Figure B11: Residential flat rate tariff with controlled load

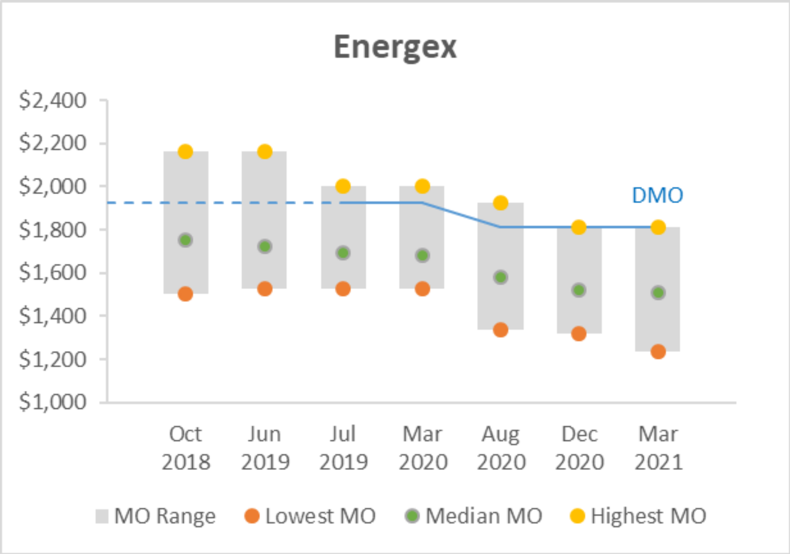
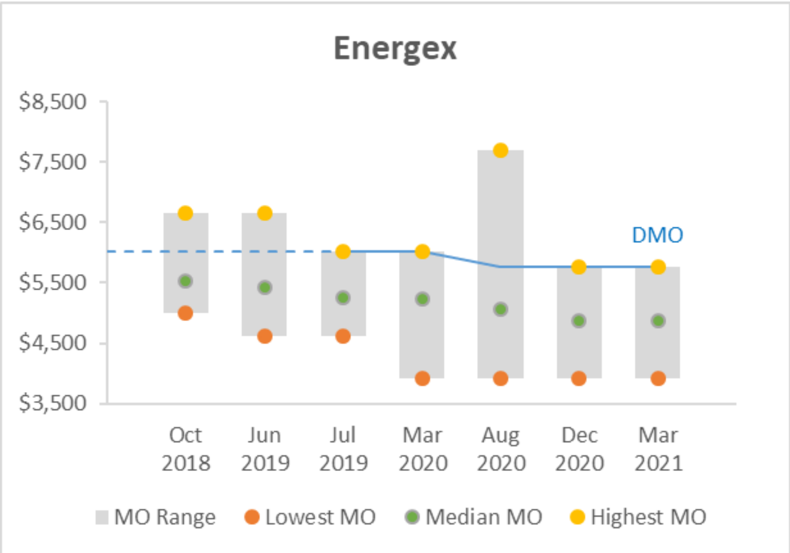


Figure B12: Small business flat rate tariff



Changes in market offer prices in SAPN's region

Figure B13: Residential flat rate tariff

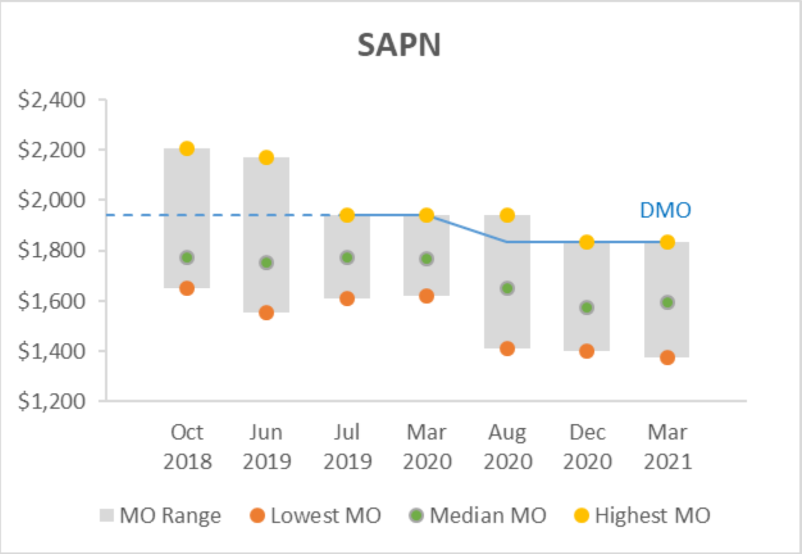


Figure B14: Residential flat rate tariff with controlled load

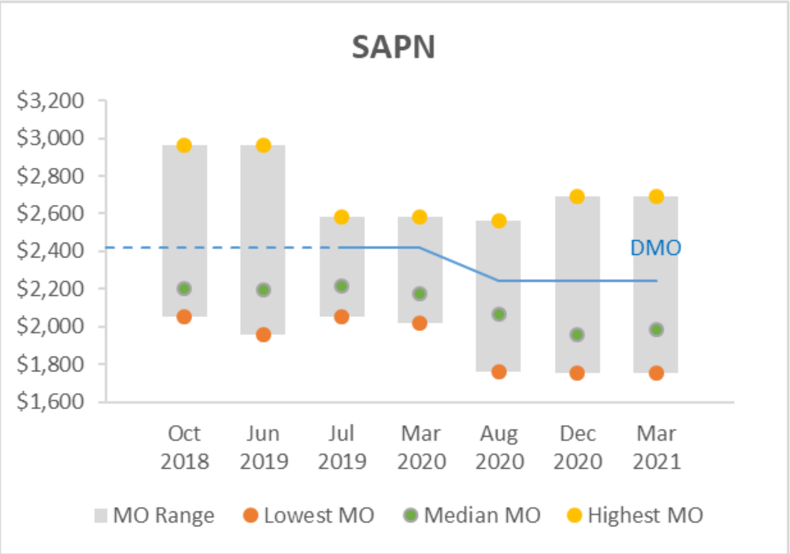
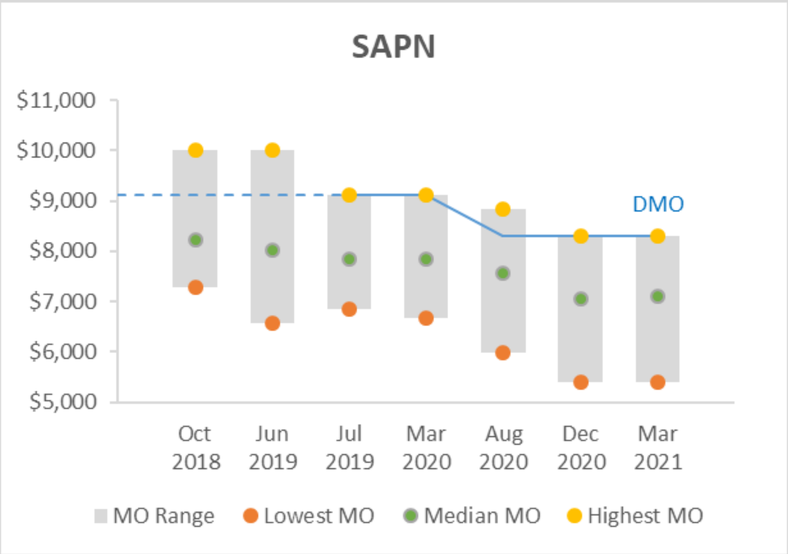


Figure B15: Small business flat rate tariff



From December 2020 to March 2021, the change in median market offer prices across the distribution regions for residential customers ranged from a reduction of 2.1 per cent (Energex) to an increase of 1.5 per cent (SAPN). For residential customers without CL, the change in the median market offer prices ranged from a reduction of 2.1 per cent (Energex) to an increase of 1.2 per cent (SAPN). For residential customers with CL the change in the median market offer price ranged from a reduction of 1.1 per cent (Endeavour) to an increase of 1.5 per cent (SAPN). The change in the median market offer price for small business customers ranged between a reduction of 1.5 per cent (Ausgrid) to an increase of 1.3 per cent (Endeavour).

Across the same time period, the lowest market offer price either decreased or remained stable. We observed some significant decreases for residential customer types in some regions. For residential customers without CL, the lowest market offer price reduced between 1.7 (SAPN) and 6.1 per cent (Endeavour). For residential customers with CL, the lowest market offer price was stable in Ausgrid and SAPN, and reduced between 2.2 per cent (Endeavour) and 6.1 per cent (Energex). The lowest market offer price for small business customers was stable in all regions except Endeavour, where there was a reduction of 0.3 per cent.

These reductions in the lowest market offer price follow previous reductions in the lowest market offer prices between August 2020 and December 2020. Since the second DMO came into effect, there has been an average 5 per cent reduction in the lowest market offer price across all regions and customer types. The lowest market offer price reduced by between 2 per cent (Endeavour small business) and 9.4 per cent (SAPN small business) for all customer types in all regions, except for Ausgrid and Energex small business customers and SAPN residential customers with controlled load, for whom it remained stable.

These decreases in the lowest market offer prices are part of a trend where small retailers, some of whom are new entrants, continue to aggressively price their market offers. These retailers may have greater exposure to wholesale spot prices and could currently be in a position to price offers lower than retailers that hedged their wholesale prices in advance. These lower priced offers coupled with the small number of offers in some regions above the DMO price cap, have led to a larger spread in the range of offer prices, similar in breadth to June 2019, prior to the introduction of DMO.

C Nominal price movements from Draft Determination to Final Determination

Table H1 shows the nominal movement for each cost component between the DMO 3 Draft Determination published on 17 February 2021 and our Final Determination.

Table H1: Changes in cost components from DMO 3 Draft to Final Determination ($nominal)

Description	DMO 3 Draft 2021-22	Network cost	Wholesale cost	Environ-mental cost	Residual cost	Overall nominal change	DMO 3 Final 2021-22
Residential without CL							
Ausgrid	**$1,372**	*$6*	*$4*	*$11*	*$1*	*$22*	**$1,393**
Endeavour	**$1,575**	*$18*	*$4*	*$13*	*$1*	*$35*	**$1,609**
Essential	**$1,849**	*$54*	*-$8*	*$12*	*$1*	*$59*	**$1,907**
Energex	**$1,439**	*$7*	*-$4*	*$12*	*$1*	*$16*	**$1,455**
SAPN	**$1,715**	*$15*	*-$26*	*$11*	*$1*	*$1*	**$1,716**
Residential with CL							
Ausgrid	**$1,886**	*$7*	*-$1*	*$19*	*$1*	*$26*	**$1,912**
Endeavour	**$1,969**	*$21*	*$3*	*$20*	*$1*	*$45*	**$2,014**
Essential	**$2,212**	*$61*	*-$21*	*$17*	*$1*	*$59*	**$2,271**
Energex	**$1,717**	*$8*	*-$1*	*$17*	*$1*	*$24*	**$1,741**
SAPN	**$2,086**	*$19*	*-$46*	*$17*	*$1*	*-$9*	**$2,077**
Small business without CL							
Ausgrid	**$6,663**	*$157*	*$19*	*$55*	*$6*	*$237*	**$6,900**
Endeavour	**$5,652**	*$16*	*$10*	*$54*	*$3*	*$84*	**$5,736**
Essential	**$7,542**	*$228*	*-$34*	*$51*	*$5*	*$249*	**$7,791**
Energex	**$5,443**	*$37*	*-$18*	*$53*	*$3*	*$75*	**$5,517**
SAPN	**$7,963**	*$139*	*-$130*	*$57*	*$3*	*$70*	**$8,033**

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 the 2021-22 indicative prices from the 2020-21 annual pricing proposals. This was the only available information at the time we made the Draft Determination. Network tariffs have been updated with the 2021-22 annual pricing proposals for the Final Determination. Network Use of System charges are the majority of network costs. There was a slight change (up to $1.03) in charges in the Alternate Control Services (ACS) for customers depending on the region. 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 a increase in ancillary services and prudential costs of 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 the Clean Energy Regulator’s issuance of binding 2020 Small-scale Technology Percentages in March. Large-scale Generation Certificate forward prices remained subdued with an influx of renewable investment coming online over the next 18 months.

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

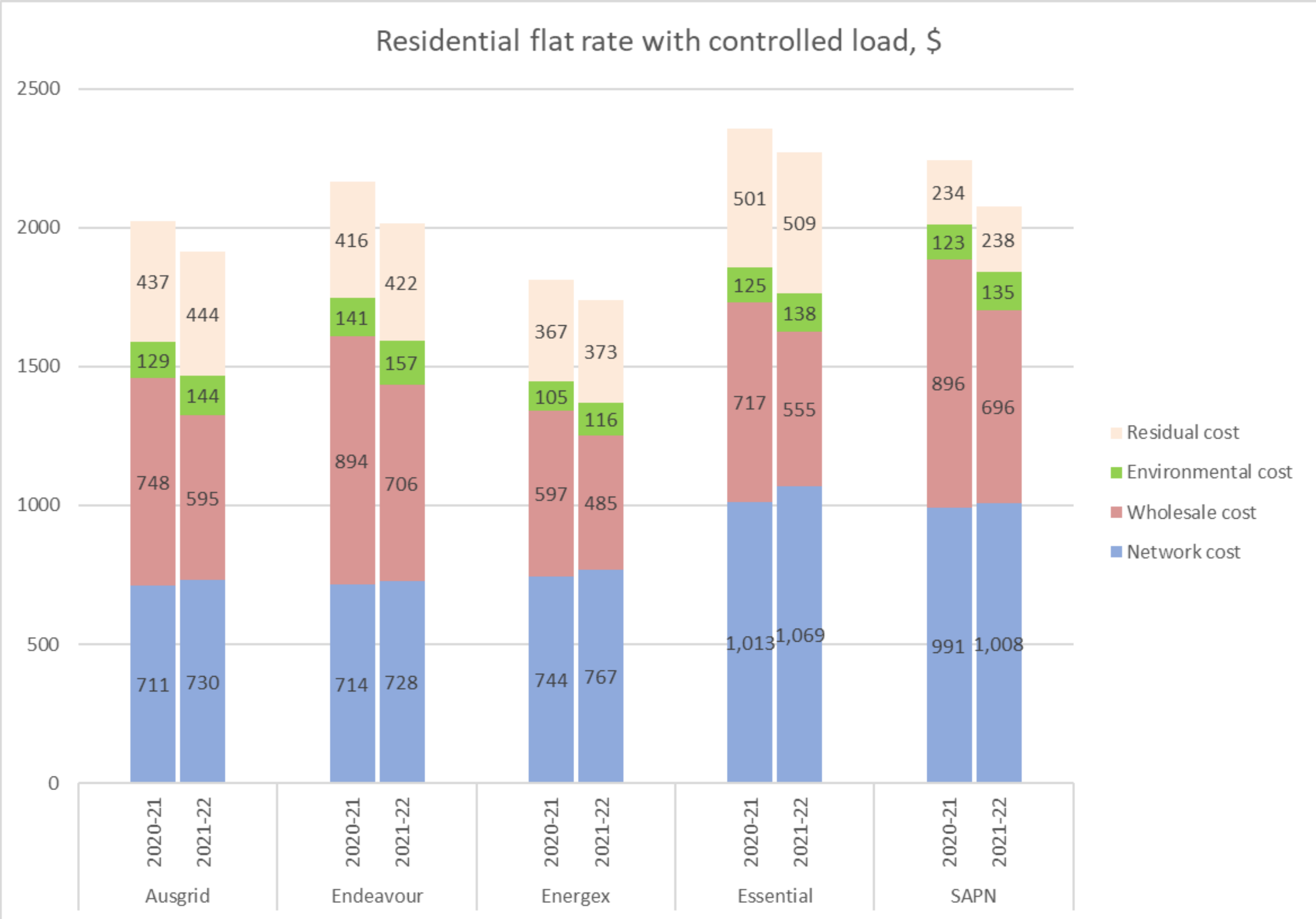
D DMO 2 to DMO 3 price movements

DMO price movements for residential flat rate tariff

Figure D1: Residential flat rate tariff

DMO price movements for residential flat rate with controlled load tariff

Figure D2: Residential flat rate with controlled load tariff



DMO price movements for Small business flat rate tariff

Figure D3: Small business flat rate tariff

E Legislative instrument

Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2021

The Australian Energy Regulator makes the following determination.

Dated 27 April 2021

Australian Energy Regulator

1. Name

This instrument is the *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2021*.

2. Commencement

This instrument commences on 1 July 2021.

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2095**	**0.189**	**0.1766**	**0.1619**	**0.1511**	**0.144**	**0.141**	**0.1417**	**0.1485**	**0.1591**	**0.1718**	**0.1849**	**0.1962**	**0.2115**	**0.2197**	**0.2251**	**0.2227**	**0.217**	**0.2126**	**0.2099**	**0.2079**	**0.2061**	**0.2045**	**0.2038**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.2038**	**0.2038**	**0.2047**	**0.2085**	**0.2133**	**0.2189**	**0.228**	**0.241**	**0.2541**	**0.2698**	**0.2875**	**0.3081**	**0.3215**	**0.3232**	**0.3156**	**0.3043**	**0.2953**	**0.2878**	**0.2735**	**0.2601**	**0.2514**	**0.2402**	**0.2333**	**0.2211**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2579**	**0.2326**	**0.2174**	**0.1992**	**0.186**	**0.1772**	**0.1735**	**0.1744**	**0.1828**	**0.1958**	**0.2115**	**0.2275**	**0.2415**	**0.2603**	**0.2705**	**0.277**	**0.274**	**0.267**	**0.2616**	**0.2584**	**0.2558**	**0.2537**	**0.2517**	**0.2509**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.2508**	**0.2508**	**0.252**	**0.2566**	**0.2625**	**0.2694**	**0.2806**	**0.2966**	**0.3127**	**0.3322**	**0.3539**	**0.3794**	**0.3957**	**0.3977**	**0.3885**	**0.3745**	**0.3635**	**0.3542**	**0.3365**	**0.3202**	**0.3094**	**0.2956**	**0.2871**	**0.2721**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2504**	**0.2329**	**0.216**	**0.2061**	**0.194**	**0.1869**	**0.1859**	**0.1896**	**0.2007**	**0.2144**	**0.2283**	**0.2414**	**0.2565**	**0.2683**	**0.2717**	**0.2629**	**0.2431**	**0.2187**	**0.201**	**0.1881**	**0.1791**	**0.1729**	**0.1681**	**0.1707**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.1783**	**0.1882**	**0.2049**	**0.2288**	**0.2547**	**0.2824**	**0.3146**	**0.3506**	**0.3817**	**0.4093**	**0.4336**	**0.4581**	**0.469**	**0.4649**	**0.4519**	**0.4331**	**0.4184**	**0.3981**	**0.3832**	**0.3577**	**0.3357**	**0.3114**	**0.2928**	**0.2756**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2657**	**0.2472**	**0.2292**	**0.2187**	**0.2059**	**0.1984**	**0.1973**	**0.2012**	**0.213**	**0.2275**	**0.2423**	**0.2562**	**0.2722**	**0.2847**	**0.2884**	**0.279**	**0.258**	**0.2321**	**0.2133**	**0.1996**	**0.1901**	**0.1835**	**0.1784**	**0.1812**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.1893**	**0.1997**	**0.2175**	**0.2429**	**0.2703**	**0.2997**	**0.3339**	**0.372**	**0.4051**	**0.4342**	**0.4601**	**0.4861**	**0.4977**	**0.4933**	**0.4796**	**0.4596**	**0.444**	**0.4225**	**0.4065**	**0.3796**	**0.3563**	**0.3304**	**0.3107**	**0.2925**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2032**	**0.1831**	**0.1696**	**0.1593**	**0.1523**	**0.1479**	**0.1455**	**0.1447**	**0.1478**	**0.1543**	**0.1678**	**0.1858**	**0.2126**	**0.2426**	**0.2658**	**0.269**	**0.2639**	**0.2567**	**0.2539**	**0.2509**	**0.2477**	**0.2459**	**0.2446**	**0.2467**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.2488**	**0.2511**	**0.2545**	**0.2574**	**0.2623**	**0.2658**	**0.2749**	**0.2904**	**0.3083**	**0.3323**	**0.3568**	**0.382**	**0.4013**	**0.4135**	**0.4043**	**0.3968**	**0.3913**	**0.3653**	**0.3417**	**0.3224**	**0.3148**	**0.3026**	**0.2697**	**0.2329**

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

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.1943**	**0.1751**	**0.1622**	**0.1524**	**0.1457**	**0.1415**	**0.1392**	**0.1384**	**0.1413**	**0.1476**	**0.1605**	**0.1777**	**0.2033**	**0.2321**	**0.2542**	**0.2573**	**0.2525**	**0.2456**	**0.2429**	**0.24**	**0.2369**	**0.2352**	**0.234**	**0.2359**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.238**	**0.2402**	**0.2434**	**0.2462**	**0.2509**	**0.2542**	**0.2629**	**0.2778**	**0.2949**	**0.3178**	**0.3412**	**0.3654**	**0.3839**	**0.3956**	**0.3868**	**0.3795**	**0.3743**	**0.3495**	**0.3269**	**0.3084**	**0.3011**	**0.2894**	**0.258**	**0.2227**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2273**	**0.218**	**0.2066**	**0.1958**	**0.1817**	**0.1728**	**0.1684**	**0.1687**	**0.1761**	**0.187**	**0.2006**	**0.2168**	**0.2349**	**0.2526**	**0.2668**	**0.2742**	**0.2711**	**0.2638**	**0.2598**	**0.2553**	**0.2522**	**0.2502**	**0.2482**	**0.2455**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.246**	**0.2467**	**0.2491**	**0.2539**	**0.2605**	**0.2682**	**0.2812**	**0.2998**	**0.3171**	**0.3325**	**0.3543**	**0.3779**	**0.3852**	**0.3743**	**0.3576**	**0.3416**	**0.3296**	**0.3124**	**0.2982**	**0.2855**	**0.2746**	**0.2643**	**0.2545**	**0.2434**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2273**	**0.218**	**0.2066**	**0.1958**	**0.1817**	**0.1728**	**0.1684**	**0.1687**	**0.1761**	**0.187**	**0.2006**	**0.2168**	**0.2349**	**0.2526**	**0.2668**	**0.2742**	**0.2711**	**0.2638**	**0.2598**	**0.2553**	**0.2522**	**0.2502**	**0.2482**	**0.2455**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.246**	**0.2467**	**0.2491**	**0.2539**	**0.2605**	**0.2682**	**0.2812**	**0.2998**	**0.3171**	**0.3324**	**0.3542**	**0.3778**	**0.3852**	**0.3743**	**0.3575**	**0.3416**	**0.3296**	**0.3124**	**0.2982**	**0.2855**	**0.2746**	**0.2644**	**0.2546**	**0.2435**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2826**	**0.2657**	**0.2289**	**0.2088**	**0.1877**	**0.1794**	**0.1644**	**0.1539**	**0.149**	**0.1521**	**0.1599**	**0.1723**	**0.176**	**0.1812**	**0.1861**	**0.1958**	**0.2023**	**0.1992**	**0.1923**	**0.1894**	**0.1878**	**0.1867**	**0.1855**	**0.1852**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.1867**	**0.1906**	**0.1928**	**0.1986**	**0.2061**	**0.218**	**0.23**	**0.246**	**0.2651**	**0.2819**	**0.2972**	**0.3157**	**0.3345**	**0.3443**	**0.3432**	**0.3336**	**0.3201**	**0.3033**	**0.2845**	**0.263**	**0.2442**	**0.2329**	**0.2768**	**0.2776**

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 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2967**	**0.279**	**0.2403**	**0.2193**	**0.197**	**0.1884**	**0.1726**	**0.1616**	**0.1564**	**0.1597**	**0.1679**	**0.181**	**0.1848**	**0.1902**	**0.1954**	**0.2056**	**0.2124**	**0.2092**	**0.2019**	**0.1989**	**0.1972**	**0.196**	**0.1947**	**0.1944**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.196**	**0.2001**	**0.2024**	**0.2085**	**0.2164**	**0.2289**	**0.2415**	**0.2583**	**0.2783**	**0.296**	**0.3121**	**0.3315**	**0.3513**	**0.3614**	**0.3604**	**0.3502**	**0.3361**	**0.3185**	**0.2987**	**0.2762**	**0.2564**	**0.2445**	**0.2906**	**0.2919**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Controlled Load usage – (1,800 kWh/yr)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.2466**	**0.2466**	**0.2466**	**0.2466**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh/	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.1761**

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 include GST)			
Distribution region	**Annual Residential Price without Controlled Load**	**Annual Residential Price with Controlled Load**	**Small Business Annual Price**
Ausgrid	$1,393	$1,912	$6,900
Endeavour Energy	$1,609	$2,014	$5,736
Energex	$1,455	$1,741	$5,517
Essential Energy	$1,907	$2,271	$7,791
SA Power Networks	$1,716	$2,077	$8,033

DATED THIS 27TH DAY OF APRIL 2021

Australian Energy Regulator

F 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 2021

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 2021.

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.