Position Paper

Default Market Offer Prices 2021-22

20 October 2020

AUSTRALIAN ENERGY REGULATOR

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Invitation for submissions

Interested parties are invited to make submissions on this Position Paper by Thursday, 19 November 2020.

We will consider and respond to all submissions received by the date in our Draft Determination.

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

Alternatively, submissions can be sent to:

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General Manager, Policy and Performance
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

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

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

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

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

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

Shortened forms

Shortened form	Extended form
ACCC	Australian Competition and Consumer Commission
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CARC	Customer acquisition and retention costs
CER	Clean Energy Regulator
CL	Controlled load
COAG Energy Council	Council of Australian Governments Energy Council
CPI	Consumer Price Index
DMO	Default market offer
DMO 1	Default market offer determination for 2019-20
DMO 2	Default market offer determination for 2020-21
DMO 3	Default market offer determination for 2021-22
DUOS	Distribution use of system
ECA	Energy Consumers Australia
EME	Energy Made Easy
ESCV	Essential Services Commission Victoria
EWOSA	Energy and Water Ombudsman South Australia
FiT	Feed-in tariff
ICRC	Independent Competition and Regulatory Commission
kW	Kilowatts
kWh	Kilowatt hours
kVa	Kilovolt amperes
LAR	Local area retailer
LGC	Large-scale Generation Certificate

Shortened form	Extended form
LRET	Large-scale Renewable Energy Target
MMO	Median market offer
MO	Market offer
MSO	Median standing offer
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGL	National Gas Law
NUOS	Network use of system
NSLP	Net System Load Profile
PIAC	Public Interest Advocacy Centre
PV	Photovoltaic system / solar power system
QCA	Queensland Competition Authority
QCOSS	Queensland Council of Social Service
REPI	Retail Electricity Pricing Inquiry
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RPP	Renewable power percentage
SAPN	SA Power Network
SBS	Solar Bonus Scheme (Queensland)
SME	Small and medium-sized business customers (enterprises)
SO	Standing offer
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
STP	Small-scale technology percentage
TOU	Time of use

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

1 Summary

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.[2]

The AER's role is to determine the DMO price each year. Our DMO price determination applies to small business and residential customers in areas where there is no other retail price regulation – South Australia, New South Wales and south-east Queensland.

The DMO price for each area also acts as a 'reference price' for residential and small business offers in that area. When advertising or promoting offers, retailers must show the price of their offer in comparison to the DMO/reference price. This aims to help customers more simply compare the price of different offers.

The *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (Regulations)* sets out the legislative framework for the DMO.

This Position Paper is the first step in our process to determine DMO prices for the 2021-22 year. This will be the third time we have determined DMO prices, and we refer to the 2021-22 DMO throughout this document as DMO 3.

Alongside this paper, we have also published a report by ACIL Allen Consulting on the approach to forecasting the wholesale and environment costs for 2021-22.

1.1 Context for this paper

The policy objectives for the DMO 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
- not reduce incentives for competition, innovation and investment by retailers, and should retain incentives for consumers to engage in the market.

In our first DMO determination, for 2019-20 (DMO 1), we achieved these objectives by setting the DMO price at the 50th percentile (mid-way) point in the range between the median standing offer (the upper bound) and median market offer (lower bound) in each distribution zone.

To continue to balance these objectives, for our second determination, for 2020-21 (DMO 2), we updated the DMO 1 price to reflect forecast changes in retailers' input costs by:

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2 See section 2.1

- 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.

1.2 DMO 3 determination – preliminary AER views

Our primary consideration in establishing the DMO 3 methodology is to maintain the balance of objectives we achieved in our DMO 1 and 2 determinations.

Our view is that indexation is the approach that is best suited to achieving this outcome.

In adopting indexation for DMO 3, we do not propose to make any adjustments or ‘true-ups’ to the DMO 3 price to reflect variances between our forecast costs for 2020-21 and actual costs. This Position Paper sets out that we consider this is a key principle underpinning our use of the DMO index in any year.

While we are proposing a largely unchanged approach to forecasting wholesale, environment and network costs, we are considering refinements to aspects of our methodology, based on stakeholder feedback. These include:

- using separate residential and small business load profiles in our wholesale electricity cost forecasting
- applying Ancillary Service Charges (ASC) at a jurisdictional level, rather than smearing the costs of these charges across all zones.

We will also consider whether COVID-19 has led to cost changes for retailers that should be accounted for in the DMO 3 price, and how these should be taken into account.

While we intend to use the forecast Australian Consumer Price Index (CPI) to adjust the retail cost component of the DMO annual bill, we are also considering whether it is reasonable for any lower costs associated with improved retailer efficiency over time to be reflected in the DMO price through some form of productivity factor.

We are also seeking feedback on options to improve the time of use (TOU) profiles, which we introduced for the first time in our DMO 2 determination.

Structure of this Position Paper

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

Chapter 3 sets out our intended approach to determine DMO 3 prices, including questions for public consultation

Chapter 4 sets out our intended approach to the DMO ‘model annual usage’ as well as consideration of costs for TOU and solar customers.

Appendix A – Questions for consultation

Appendix B – Market offer analysis for each distribution region

1.3 Next steps

Table 1 outlines our timetable for the development of DMO 3 prices.

Table 1 – DMO 3 proposed timetable

Milestone	Date
Publish Position Paper	20 October 2020
Submissions due	19 November 2020
Online stakeholder forum	29 October 2020
Publish Draft Determination	Early February 2021
Submissions due	Early March 2021
Issue Final Determination	By 1 May 2021
DMO 2021-22 in force	1 July 2021

2 Background

Who we are

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

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

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

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

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

2.1 Policy context for the Default Market Offer

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

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

The Commonwealth Government accepted the recommendation and made the regulations giving effect to the DMO that commenced on 1 July 2019. The legislative framework for determining DMO prices is contained in the *Competition and Consumer (Industry Code – Electricity Retail) Regulations* 2019 (the Regulations).[3]

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3 https://www.legislation.gov.au/Details/F2019L00530

The ACCC was clear that the purpose of the DMO was to act as a fall-back for those who are not engaged in the market, and should not be a low-priced alternative to a market offer.[4]

It provided clear guidance about how the default offer price should be set. Specifically, it made clear that while the DMO price must reduce unjustifiably high standing offer prices:

- it should allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and customer acquisition and retention costs (CARC)
- it should not dis-incentivise competition, innovation and investment by retailers, and should 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 zone 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 remains our primary consideration as we commence the process of determining DMO 3 prices.

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

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

5 AER, *Final determination default market offer prices 2020-21*, p. 27.

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

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

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

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

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

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.

Table 2 – Standing offer customers in DMO areas

	Residential standing offer customers (Number and %)	Small business standing offer customers (Number and %)
NSW	392,025 (11.97%)	71,215 (21.6%)
South-east QLD Figures extrapolated from all QLD by excluding Ergon customers. We note other retailers have customers in regional QLD so figure is approximate	172,320 (12.09%)	25,338 (23.34%)
SA	65,019 (8%)	13,446 (15.32%)
Total standing offer customers	**629,364**	**109,999**

Source: AER Retail Market Performance update, Quarter 3 2019-20

2.2 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]
- 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:

[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).

[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.

- 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 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 consider relevant.[15] Our previous determinations have set out how we have had regard to these factors in setting the DMO price.[16]

Reference price provisions

Part 2 of the Regulations prescribes a mandatory industry code (the Code) for the purposes of Part IVB of *the Competition and Consumer Act 2010*. The Code contains the DMO reference price provisions, which require:

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

[16] AER, Final determination, default market offer prices 2019-2020, p. 27 – 29; AER, Final determination, default market offer prices 2020-21, p. 75 – 77.

- standing offer prices for small customers must not exceed a price determined by the AER[17]
- small customers must be told how a retailer's prices compare with the AER-determined annual price[18]
- the most prominent price-related feature in an advertisement must not be a conditional discount, and any conditions on other discounts must be clearly displayed.[19]

As the Code has been made under the Competition and Consumer Act, enforcement and compliance with these provisions is the responsibility of the ACCC.

2.3 Default Market Offer – preliminary market observations for 2020-21

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

As in previous DMO documents, we have analysed retail market offer prices for the DMO regions, tracking changes over time since October 2018 (prior to the announcement of the DMO policy) to the current period.

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

We note that a range of factors influence retailers' market offer pricing, and that specific price trends should not be attributed to the introduction of the DMO.

Factors likely to be influencing market offer prices in 2020-21 are likely to include:

- lower wholesale electricity purchase costs, due to a combination of lower gas prices for gas fired generation and strong increase in renewable investment
- changes in network businesses' charges – these have decreased in most areas from 2019-20 levels
- individual retailer pricing strategy and market positioning.

Changes in market offer prices observed in August 2020 are likely to be a result of some combination of these factors.

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17 Regulations, s. 10.

18 Regulations, s. 12.

19 Regulations, s. 14.

Median market offer prices

From March 2020 to August 2020, median market offers prices decreased in all distribution regions for all customer types. For residential customers the median market offer reduced between 3.2 (Ausgrid) and 6.6 per cent (SAPN), and between 2.7 (Essential) and 5.9 per cent (Energex) for customers with controlled loads. The median market offers for small businesses reduced between 0.5 (Endeavour) and 3.5 per cent (SAPN).

In some regions, we noted the reduction in the median market offer is larger than the equivalent reduction in the DMO price. Our analysis indicates that this outcome is likely due to a significant increase in the number of lower priced offers in these regions.

Figure 1 illustrates this for residential customers (no CL) in the SAPN region, one area where the median market offer decreased more than the DMO, and for small business offers in the Ausgrid region.

The charts, which reflect trends in most regions show that there were significantly more low-price offers available in August 2020[20] than in July 2019.

Our analysis shows the increase in the median market offer/DMO gap is due to a higher prevalence of low cost offers in these regions driven by small retailers, including new entrants. Key reasons for the increase in low priced offers are likely to include:

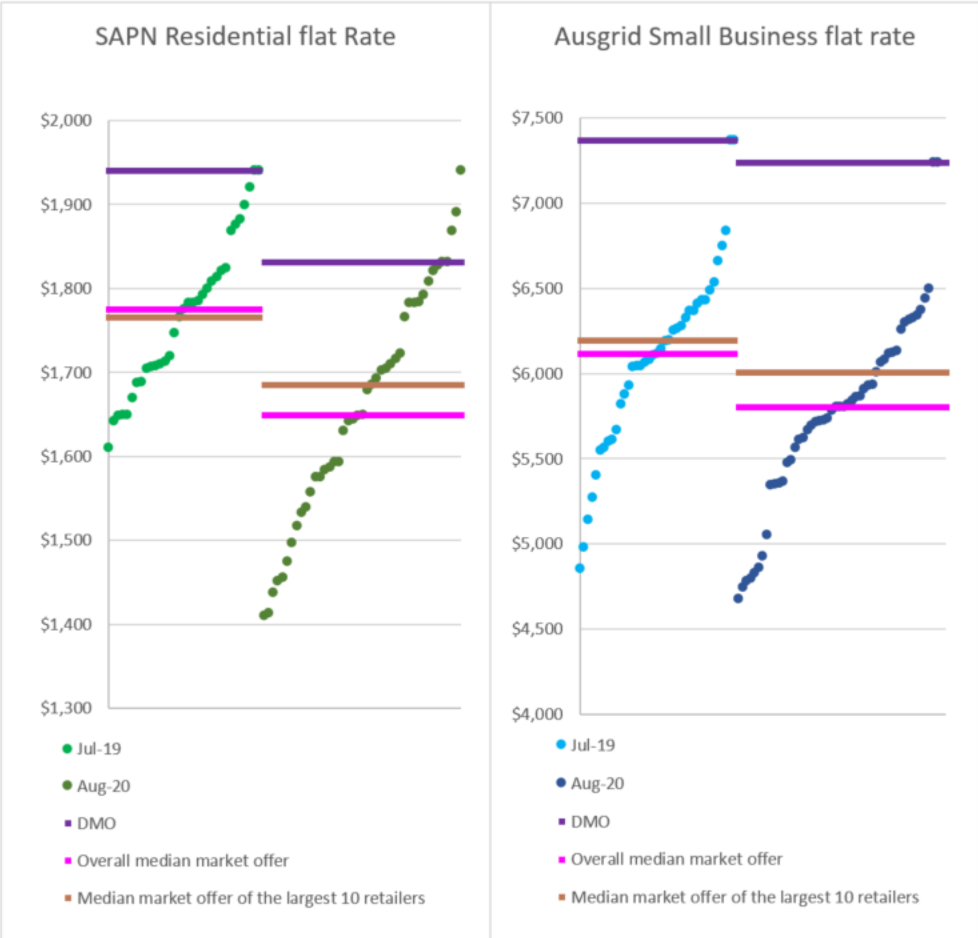
- These retailers' may have greater spot market exposure, given current low prices.
- Aggressive pricing strategies that sacrifice margin to gain market share.

The influence of smaller retailers on the median price is highlighted by the brown horizontal line, which shows the median market offer of the ten largest retailers[21] (accounting for more than 90 per cent of customers). The median offer among these retailers has more closely followed the movement in the DMO.

[20] We analysed offers in August 2020 due to some retailers' delaying their introduction of new prices, which normally occur in July each year.

[21] By customer numbers.

Figure 1 – Market offer price spread comparison, July 2019 and August 2020



Highest and lowest market offer prices

The highest price offer in each region has remained around the DMO level in most regions, although we note it is above the DMO in some areas for some customer types.

Between March 2020 and August 2020, the lowest priced market offer in each region decreased for all customer types in all regions, with the exception of small businesses in Energex's region, which remained flat. We observed some significant decreases in this metric in some regions. For residential customers the lowest market offer reduced from 2019 levels by between 8.1 (Essential) and 14.4 per cent (Energex) and between 5.8 (Essential) and 13 per cent (SAPN) for customers with controlled loads. The lowest market offers for small businesses reduced between 0.8 (Essential) and 10.5 per cent (SAPN).

Detailed analysis of market offer prices is included in **Appendix B**.

Other DMO commentary

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

Other regulators' have considered some of these issues, and provided commentary about the impact of the DMO.

AEMC Retail Competition Review 2020

In June 2020, the AEMC published its 2020 Retail Energy Competition Review, which included analysis of the market following the introduction of the DMO.[22]

Prior to the DMO's taking effect in July 2019, the AEMC provided advice to COAG Energy Council that the introduction of the DMO may lead to:

- a decrease in price dispersion, including price increases in the lower priced market offers available to consumers, which may reduce the incentive for consumers to engage in the market and could lead to decreased switching.
- retailers attempting to recover lost revenue by increasing prices for their other customers, or at least in the short term, withdrawing their lower priced market offers.
- increased risk to retailers driving higher financing and overall costs, lower levels of innovation leading to a smaller range of products and services, and higher barriers to entry and changes to consumer behaviour resulting in decreased competition.[23]

The 2020 retail competition review noted that while it was too early to assess the full impact of the DMO, its analysis showed competition had continued to develop and that its earlier predictions had not yet eventuated.

The AEMC noted that in DMO regions between 2019 and 2020:

- Market concentration continued to decrease. New retailers entered the market and some brands expanded into new jurisdictions. There was a continued trend of consumers switching from Big 3 to Tier Two retailers.
- Average and median residential offers below the DMO were largely stable with minor movements up or down, depending on the network distribution area.
- In all distribution areas where the DMO was introduced (except Essential Energy) retailers reduced the price of their lowest small business offers in 2020.

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22 AEMC: *2020 Retail Energy Competition Review*, Final report, 30 June 2020.

23 AEMC: *2020 retail energy competition review*, Final report, 30 June 2020, p. 3–4.

- Most retailers have removed market offers priced above the DMO.
- The introduction of a price cap on standing offers has generally reduced price dispersion.
- In all DMO jurisdictions, the proportion of consumers on standing offers decreased, although the rate of decrease slowed.

3 DMO 2021-22 price determination – proposed approach

We will re-apply the indexation approach for determining DMO 3 prices. This means we will:

- update the DMO 2 price to reflect forecast changes in wholesale energy, environmental and network costs for 2021-22
- adjust the retail costs component of the DMO 2 annual bill by the forecast Australian Consumer Price Index (CPI)
- consider changes to retailer costs due to unforeseen and unavoidable external factors under the step change framework we developed for DMO 2.

We also are considering refinements to some elements of our methodology based on stakeholder submissions in DMO 2.

This chapter sets out our reasoning, as well as the key issues and questions we are seeking stakeholder feedback on.

3.1 Pricing methodology for DMO 2021-22

Continuing the indexation approach

In our DMO 2 determination, we set out why we considered the indexation approach is the appropriate methodology for setting the DMO price:

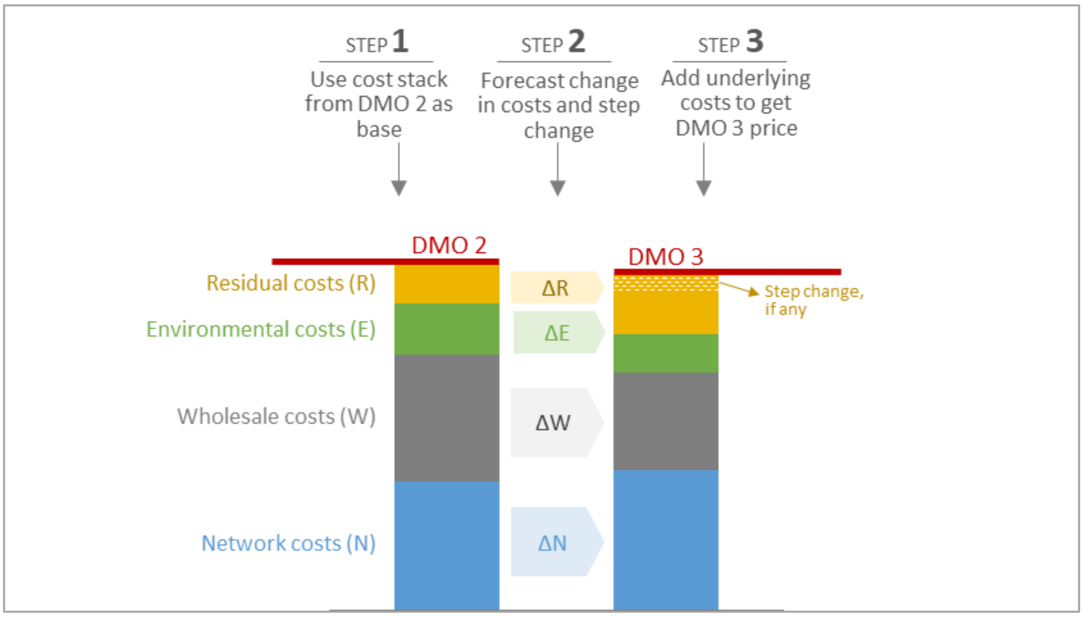
- It preserves the DMO 1 retail residual cost component – which balanced the policy objectives – at the same relative level across years.
- The various possible alternative approaches to determining prices are not well-suited to the DMO objectives.
    - *Cost-based (or 'bottom-up') approach* – This is the typical approach used by jurisdictional regulators for retail price regulation. This involves the regulator estimating the costs that a representative 'efficient' retailer would incur for supplying services to consumers. For our purposes, this approach would also require us to determine what amount above the estimate of efficient costs we should allow to meet our policy objectives. Given the DMO is not aiming to identify efficient costs, we considered this option was not suitable for our policy objectives.
    - *Price-based approach* – We considered options to set the DMO price in relation to market offers. While transparent, we considered there was a significant risk of retailers causing market distortions or manipulating the offer spread in response to this methodology.

These characteristics remain relevant for the DMO 3 determination. In the current context of the ongoing COVID-19 pandemic, we also note:

- The indexation approach is flexible enough to deal with the impacts of unforeseen events, including COVID-19, as well as other changes in retailers' costs, through the step change framework we developed for DMO 2.
- Continuing a known approach provides consistency and certainty for stakeholders, which is appropriate given other current market uncertainties relating to COVID-19.

Figure 2 represents applying the indexation approach to update the DMO 2 prices to determine the DMO 3 prices.

Figure 2 – Illustrative example of DMO 3 price assessment methodology



We discuss the forecasting approach for each of the cost components in detail in Chapter 3.2. Specific questions relating to components of the cost stack are included in the respective sections.

DMO 2 starting point

Based on our analysis and the available evidence, we are satisfied that the DMO 2 price is a suitable basis from which to apply the index for a further year.

For the DMO 2 determination, we were satisfied that the DMO 1 price balanced the key DMO policy objectives, and was therefore a suitable starting point from which to apply the indexation approach.

For DMO 3, based on our analysis, we are satisfied that the DMO 2 price has also balanced the policy objectives, and is a suitable point from which to apply the indexation approach.

Table 3 sets out our consideration of how our previous determinations met each of the three policy objectives.

Table 3 – How DMO 1 and 2 determinations met the policy objectives

Policy objective	DMO 1	DMO 2
Preventing excessive standing offer prices	The introduction of DMO prices in 2019-20 led to significant decreases in the standing offer prices for residential and small business customers, with reductions from the median standing offer level ranging between: • $118 and $181 for residential customers on a flat rate tariff • $169 and $236 for residential customers on a flat rate tariff with controlled load • $457 and $896 for small business customers on a flat rate tariff.	The application of CPI to the DMO 1 retail residual cost component means the reductions from excessive levels we achieved in DMO 1 have been retained in DMO 2.
Allowing retailers to recover their efficient costs	The DMO 1 price was well above the median market offer price in each distribution region, which we considered was a reasonable indication of retailers' efficient costs. • $186 and $236 for residential customers on a flat rate tariff • $206 and $307 for residential customers on a flat rate tariff with a controlled load • $776 and $1277 for small business customers on a flat rate tariff.	DMO 2 prices remain well above the median market offer price in each region. The difference between the DMO 2 price and the median market offer ranged between: • $183 and $298 for residential customers on a flat rate tariff • $180 and $366 for residential customers on a flat rate tariff with a controlled load • $691 and $1435 for small business customers on a flat rate tariff.
Not dis-incentivising competition, innovation and investment by retailers, and retaining incentives for consumers to	The DMO 1 price was significantly higher than most market offers in each distribution region, meaning customers on a DMO had an incentive to shop around and switch. The difference between the DMO 1 price and the lowest	The DMO 2 price remains higher than most market offers, with significant margin between the lowest market offer and the DMO indicating there are strong incentives for customers to shop around and switch. The difference between the DMO 2 price and the lowest market offer ranged between:

engage in the market	market offer in each region ranged between: • $280 and $369 for residential customers on a flat rate tariff • $364 and $448 for residential customers on a flat rate tariff with a controlled load • $1303 and $2519 for small business customers on a flat rate tariff.	• $399 and $508 for residential customers on a flat rate tariff • $478 and $576 for residential customers on a flat rate tariff with a controlled load • $1602 and $2564 for small business customers on a flat rate tariff. We also note the AEMC's preliminary observations that competition indicators have not decreased in DMO regions, including: • the proportion of customers on standing offers continues to decrease • market concentration continues to reduce • new retailers have entered the market.[24]

Retrospectively adjusting previous forecasts

In adopting the indexation approach for DMO 3 we do not propose to make any adjustments or 'true-ups' to the DMO 3 price to reflect variances between our forecast costs and assumptions for 2020-21 and actual costs.

Given the forward-looking nature of the DMO, in any given year the forecast cost inputs we use for our DMO determination may vary from the 'actual' prices that eventuate.

Following our DMO 2 determination, some retailers raised[25] concerns that our forecasts did not accurately capture changes in key retailer costs.

- *Network costs* – The retailers highlighted that we underestimated network costs by using indicative, rather than actual network charges, which were higher. This impacted retailers' ability to recover costs under the DMO price cap.

  This issues are discussed in the Network Costs section below, but in summary our requirement to publish DMO prices by 1 May meant final network prices

24 AEMC: *2020 retail energy competition review*, Final report, 30 June 2020, p. xii, 4, 27 – 29, 44 – 45.

25 Retailer correspondence to the AER; AEC media release – *Default Market Offer: missing the mark in 2020-21* - https://www.energycouncil.com.au/analysis/default-market-offer-missing-the-mark-in-2020-21/

were not available for use in our DMO calculations and indicative tariffs were the best available information.

- *Small-scale Renewable Energy Scheme (SRES)* – we indexed the change in cost of the Small-scale Renewable Energy Scheme (SRES) based on updated information for 2019-20, rather than the estimated costs included in the 2019-20 DMO.
- *Ancillary Service Charges* (ACS) – we averaged the cost of the ancillary services across all customers in the National Electricity Market (NEM), even though these costs are specific to jurisdictions, so can vary substantially.
- *COVID-19 impact* – we did not make any allowance for the impact on retailers of dealing with COVID-19, particularly in relation to bad debt.

Retailers have suggested different ways we could address variances of this kind, including:

- *Ex-post adjustment (or 'true-up')* – We could adjust the DMO price to account for any difference between forecast costs and 'actual' prices over the preceding year.
- *Re-setting the base* – We could adjust the previous DMO cost stack components to reflect actual costs, before forecasting forward.
- *Additional 'risk allowance'* – We could adjust the DMO price by a percentage or dollar amount to allow a buffer for any shortfall between forecast costs and 'actual' prices over the previous or current year.

Our view is that in each year the DMO price should be based on prices arrived at in the previous determinations, with no adjustments made for account for variance between actual and forecast costs. Our reasons for this are:

- The DMO price is not intended to be an accurate reflection of retailers' efficient costs. Making adjustments in this way suggests there is a 'correct' DMO price in circumstances where the AER has not adopted a detailed 'bottom up' cost build-up methodology to determining the DMO.
- The DMO is a forward-looking instrument, based on the best information available at the time. This approach is transparent and conceptually simple. If we were to adjust the price for one component of the DMO cost stack, it follows that we would have to adjust all components. This would decrease year-on-year comparability, and reduce stakeholder certainty in the DMO pricing outcomes.
- The DMO price is sufficiently high that an under-estimation of costs should not impact on retailers' ability to recover costs for standing offer customers.
- The nature of our DMO approach means that while variance between forecast and actual costs may disadvantage retailers in some years, it will benefit them in others. In a scenario where our forecasts were higher than actual costs, we would not seek to adjust the DMO price to reflect this.

> **Stakeholder question:**
>
> 1. Do you agree with the principle that forecasts and assumptions from previous DMO determinations should not be retrospectively amended to reflect actual information?

Indexation approach in future years

Our current view is that the indexation approach will remain fit for purpose for future DMO determinations. It should continue to enable the determination of DMO prices that balance the objectives achieved in DMO 1, while providing stakeholders with regulatory certainty and consistency across multiple years.

We acknowledge that over time variance between forecasts used to determine the DMO each year, and actual costs, may influence whether the price continues to the balance of objectives. For example, differences in actual and forecast CPI over time may result in a retail cost component that diverges from the DMO 1 retail component.

To address this concern, it may be that we should review our methodology or rebase our cost component assumptions in a future determination.

The Department of Industry, Science, Environment and Resources (DISER) has committed to a review of the Regulations.[26] This review may lead to changes to the DMO Regulations or policy objectives, which we would be required to take into account in subsequent decisions.

Given this possibility, we propose to further consider our application of the indexation approach, following DISER's review.

3.2 Forecasting changes in the cost of supply

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

3.2.1 Wholesale costs

Overview

Wholesale costs comprises **wholesale energy costs** associated with hedging and spot market costs, as well as **other energy costs** incurred in participating in the National Electricity Market (NEM) wholesale market.

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[26] Regulations, Explanatory Statement, p. 2 - https://www.legislation.gov.au/Details/F2019L00530/Explanatory%20Statement/Text.

As outlined in our DMO 2 Final Determination, we used a market-based approach, which involved the development of a retailer hedge book consisting of the base, peak and cap contracts. Stakeholders supported this approach to forecast wholesale costs given the financial derivative data is readily available and transparent.

For DMO 3, we propose to retain the market-based approach to forecasting wholesale energy costs (WEC) while making a minor adjustment to how we allocate ancillary services charges.

Under the methodology used by our consultant ACIL Allen (the 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, estimated uptake of rooftop solar photovoltaic (PV) and weather simulations in respect to their impact on demand and availability of renewable resources.

The supply-side forecast, 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 ASC for services to manage power system safety, security and reliability.

Details of the Consultant's wholesale cost forecasting methodology are set out in its Default Market Offer 2021-22 technical report.[27]

Assumed hedging strategy

In the DMO 2 Final Determination, we set out that an appropriate hedged position was based on a retailer's expectation of wholesale spot price outcomes for the relevant period. A retailer applies a hedging strategy to achieve the optimal hedging product mix and exposure to the spot price. We considered a risk-averse retailer with an established customer load was an appropriate assumption given our policy objectives, forecasting approach and the information available. In summary, the approach assumed:

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[27] See - https://www.aer.gov.au/retail-markets/guidelines-reviews/retail-electricity-prices-review-determination-of-default-market-offer-prices-2021-22.

- a retailer aims to minimise the variability in the wholesale electricity cost of supplying its forecast customer load prior to the commencement of the pricing period
- the hedge book consists of a portfolio of base, peak and cap quarterly contracts
- the retailer gradually builds the hedge book over time in the lead up to the determination period, where the prices are weighted by actual trade volumes. There is no assumed starting point for the book build. It would start when the first trade is listed on the ASX Energy with pricing and volume information, and extend up to three months before the beginning of a determination period.

Rather than prescribing a particular pattern and starting time in the hedge book build up, our Consultant uses all trades back to the first trade recorded by ASX Energy for the given contract product. This generally reflects, in practice, how retailers build up their portfolio of hedging contracts over time (given it is based on observable trades).

Observable trades recorded by ASX Energy generally commence 36 months prior to the start of the relevant period, although the large majority of trades (typically around 98 per cent) occur in the 24 months prior to the start of that period.

This approach reflects our view of how a risk-averse retailer would build a portfolio of hedging contracts over time. This progressive and gradual book build process, which considers all contract trades, accounts for retailers that adapt their hedging strategies over time to reflect changes in their market share and customer load, including customer churn.

We recognise that individual retailers will have different risk appetites and approaches to managing their underlying costs of supply. However, it is not practical to attempt to devise a different assumed hedging strategy for each individual retailer.

We are interested in stakeholders' views as to whether our current book build assumption of a risk-averse retailer remains reasonable, or whether a shorter book build period – for example, 18 months – would be a more appropriate contracting strategy, given the DMO objectives. Supporting information and data clearly setting out the rationale and benefits of any alternative approach would assist our consideration of this issue.

Stakeholder question:

2. Does our assumption of a risk averse retailer building their hedge book from the time of the first trade recorded by ASX Energy remain appropriate, or is a shorter period justified? What is an appropriate period and why?

Cost of a retailers' hedging strategy and residual exposure to forecast spot market prices

Our Consultant runs over 500 simulations of spot price outcomes, along with the application of contracting strategies, and bases its estimate of wholesale energy costs at the 95th percentile of the distribution of all outcomes. That is, the wholesale energy cost used is exceeded by only 5 per cent of the simulated wholesale energy costs outcomes.

It adopts the 95th percentile estimate, rather than the median or another value, to minimise the risk of understating the actual wholesale energy costs incurred by a retailer, and accounts for uncertainties involved in forecasting wholesale costs.

We considered that this is approach was appropriate given:

- the objectives of the DMO price being set above efficient costs so as not to dis-incentivise competition, innovation and investment by retailers, and retain incentives for consumers to engage in the market
- the greater risks to competition and retailer cost recovery from an underestimated DMO price, compared to an overestimated price.

Conversely however, it may be the case that the 95th percentile creates a risk of systemic over-estimation of wholesale costs.

We are interested in stakeholders' views about whether the 95th percentile estimate remains appropriate. For example, to what extent is it representative of a retailers' contracting strategy and does it create a systemic risk of cost overestimation?

Stakeholder question:

3. Does the Consultant's 95th percentile estimate remain appropriate, given the hedging strategy? What alternative percentile could be applied and what would the justification be?

Ancillary Services

ASC are estimated using weekly aggregated settlements data published by AEMO. These charges vary year-on-year, dictated by market conditions and demand for Frequency Control Ancillary Services (FCAS), making it difficult to project into the future. For DMO 2, the forecast ancillary services charges for all distribution zones were based on average NEM FCAS costs published by AEMO over the 52 weeks preceding 25 March 2020.

We note that in the final determination of DMO 2 prices, there was an increase in the average FCAS costs due to a few events, including the South Australian islanding in

November 2019[28] and the Heywood interconnector outage in January 2020.[29] A few stakeholders noted that FCAS charges are paid at a NEM regional level and passed on by retailers to the relevant retail customers in that region.

We consider moving to a NEM regional-based allocation would more closely reflect the actual manner in which the ancillary costs are incurred by retailers. Therefore for DMO 3, we propose to forecast ASC separately for each NEM region.

Stakeholder question:

4. Do you agree with our proposed approach to assign ancillary service charges to each state, rather than smeared across the DMO jurisdictions?

5 minute settlement

On 9 July 2020 the AEMC published its final determination and rule regarding implementation of 5 minute settlement (5MS) arrangements, with the introduction of 5MS scheduled to occur on 1 October 2021.[30] As outlined in our Consultant's technical report,[31] the AEMC noted concerns from some stakeholders that the introduction of 5MS could potentially lead to a reduced volume of cap contracts as new five minute cap products for the 2021-22 period are not yet listed on the ASX Energy.

The current trading of quarterly caps will continue to 30 September 2021. However, there would not be any cap product, contract price and volume data available from ASX Energy for the remaining three quarters of 2021-22. As cap products form an important part of the assumed retailer's hedging strategy, our Consultant has outlined options in the technical report that it expects would be available in absence of listed cap contract price and volume data, including new financial derivative products that might be developed in the time period leading to the next financial year. On this basis, our Consultant considers that it should be possible to continue with our existing wholesale cost forecasting methodology notwithstanding the potential impacts of 5MS on participant contracting arrangements.

We consider that any noticeable change in the available data and inclusion of any other contract products that are traded in the market going forward will be reflected in the hedging strategy adopted by our Consultant. This would not require any change to the overall wholesale cost forecast approach.

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28 AEMO, December 2019, Preliminary Report Non-Credible Separation Event South Australia – Victoria on 16 November 2019.

29 AEMO, April 2020, Preliminary Report – Victoria and South Australia Separation Event, 31 January 2020.

30 AEMC, National Electricity Amendment (Delayed implementation of five minute and global settlement) Rule 2020 No. 10.

31 ACIL Allen Consulting, 23 September 2020, Default Market Offer 2021-22 Wholesale Energy and Environmental Costs Methodology Paper for DMO 3, p. 19.

Load profiles

Our Consultant uses Net System Load Profile (NSLP) in its wholesale forecasting. This is an aggregated load profile for basic meters that does not distinguish between small business and residential customers.

Some stakeholders submitted in DMO 2 that load profiles should be differentiated between residential and small business customers when forecasting wholesale costs.

They noted that the NSLP is not an accurate representation of the individual residential and small business customers, resulting in forecasts that do not accurately reflect retailers' costs for each customer type. They submitted that separate load profiles for residential and small business customers would lead to more representative forecasts.

Developing separate profiles requires reliable and transparent data collected from interval and smart meters, for residential and small business customers. In our DMO 2 Final Determination we agreed that, while it would be preferable to allocate costs to each customer type, this required detailed interval meter data, which we did not have access to. We also noted that due to the low proportion of interval meters in DMO jurisdictions, any profiles based on usage data from these meters may not be representative of the broader population.

Noting the progressive increase in uptake of smart meters, we undertook to investigate this issue further for DMO 3.

We are currently undertaking an information request process to gather residential and small business interval/smart load profile data from AEMO for the DMO regions.

We will make an initial assessment about whether the differences between the NSLP and individual residential and small business load profiles across the distribution regions are significant enough to warrant changing the forecasting methodology (which as noted, is transparent and uses public information).

If the difference in the profiles is material, we will work with our Consultant to develop a methodology to reflect this in our forecasting approach.

We would consult on any approach later in our determination process.

Stakeholder question:

5. What are the implications of differentiating between residential and small business load profiles to forecast wholesale costs?

COVID-19 impact on wholesale costs

The methodology developed by our Consultant will account for any observed impacts of COVID-19 pandemic on the wholesale electricity market for 2021-22. As outlined in the Consultant report, the following parameters are likely to be impacted:

- *Demand forecast* – AEMO's ESOO has incorporated demand forecasts that include the projected impacts of the COVID-19. Since the Consultant uses the forecasts provided by AEMO in the ESOO, any resulting change in demand will be considered through the methodology.
- *Demand profiles* – For DMO 3, the wholesale costs will take into account the load profiles dating back to 2019-20, and will include the level and pattern of demand from the time the first pandemic response measures were introduced in DMO regions, between mid-March 2020 and June 2020. The changes observed to date are further discussed in the Consultant's technical report.
- *Contract prices* – As outlined earlier in this section, our methodology considers the trade-weighted contract prices since the contracts first started trading on the exchange. Therefore the market's view of the impact of COVID-19 on wholesale contract prices in 2021-22 will be reflected in the forward market contracts, and will eventually be reflected in our wholesale costs.
- *Spot prices* – The assumptions used by ACIL Allen in forecasting the wholesale spot prices is a function of simulated supply and demand.

In line with the above considerations, we consider that ACIL Allen's methodology appropriately captures the impacts of COVID-19 on the wholesale electricity market, and its associated costs.

Stakeholder question:

6. Do you agree with our proposed approach to continue using the DMO 2 wholesale energy cost forecasting methodology?

3.2.2 Environmental costs

Overview

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

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

The RET is made up of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). The LRET cost is incurred to acquire the necessary amount of Large-scale Generation Certificates (LGCs). LGC surrender for each retailer is determined by the electricity consumed by its customer base in that year multiplied by the Renewable Power Percentage (RPP) set annually for a calendar year by the Minister for Energy.[32] For the SRES, small-scale technology certificates (STCs) are similarly surrendered by retailers. These certificates correspond to electricity generation by rooftop solar PV units and solar water heaters. Retailers have the option to either purchase STCs on the market or from the STC Clearing House. STC surrender for each retailer is estimated annually for a calendar year using the Small-scale Technology Percentage (STP).[33]

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

Large-scale Generation Certificates

During DMO 2, some retailers raised concerns with our approach to estimating LRET costs. They suggested our approach using LGC forward prices is not representative of the actual cost that they incur through their respective Power Purchase Agreements (PPA's) with large-scale renewable energy generators, or internal investment in renewable energy generation units for vertically integrated companies.[34]

PPAs are private contracts between electricity retailers and renewable energy projects. The Agreements include the exchange of LGCs for a contracted price. PPAs are usually longer-term contracts, may have a range of formats, and may include various non-price terms.

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

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

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

In our DMO 2 Draft Determination, we identified the complexities in determining a benchmark LGC price through the use of PPA information. We noted the various forms, durations and commercial drivers for these arrangements and the challenges this would create for estimating a benchmark LGC price for a specific regulatory period. We acknowledge the majority of PPAs were entered into several years ago, therefore the cost of the green component (the LGCs) may be higher than the cost of acquiring the LGCs through a brokerage platform currently.

We recognised that some retailers would not rely on the spot market to acquire LGCs, but would acquire LGCs in the years leading up to the relevant pricing period. However, not all retailers are in a position to be able to enter into PPAs and instead make use of other hedging methods.

The CER's latest Carbon Market Report[35] shows that LGCs trade reasonably well in the market. For example, LGC market trades during calendar year 2019 amounted to over 69 million LGCs, or over two times the mandated LRET target for 2019. In addition, analysis by our Consultant shows that TFS Green Australia (a market leader in the brokerage of environmental certificates) cumulative brokered forward contracts for calendar year 2019 since commencement of trading, comprise around 40 per cent of the LRET target for 2019. If 2019 spot trades are included, then this share increases to around 53 per cent. This indicates that the broker data used in estimating LGC prices in this determination is robust and representative of the broader LGC market.

Therefore, we maintain the view that LGC brokerage prices that are transparent, publicly available and a function of market conditions, are the best available proxy for assessing the cost of acquiring LGCs.

More generally, we consider there are significant challenges in reconciling an approach that uses historical LCG prices from PPA with the forward-looking DMO approach. In addition, we have not adopted a specific cost build-up approach for other elements of the DMO so it would be inconsistent for us to do this for PPAs with respect to environmental costs.

Methodology

Our approach includes three steps to estimate RET costs.

1. **Estimate the RPP and STP** – Consider actual values of the renewable percentages (RPP and STP) for 2021, which would be published by the CER in March 2021, and estimated values for RPP and STP for 2022.
2. **Estimate the LGC and STC price** – Use average LGC prices and clearing house STC prices for both calendar years. The average LGC prices would be estimated using LGC forward prices provided by an energy brokerage company.

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

3. **Estimate RET –** Compute RET costs for the relevant calendar years by multiplying certificate prices with renewable percentages, and averaging the two calendar years to derive the costs for financial year 2021-22.

Our Consultant calculates a volume-weighted average since trading began (October 2016 for 2019 LGCs, May 2017 for 2020, May 2018 for 2021 and May 2019 for 2022 LGCs). We consider this methodology is likely to be the most robust as it takes into account the entire time period in which trades occur.

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

Stakeholder question:

7. Do you agree with our proposed approach to continue using the DMO 2 environmental costs methodology?

3.2.3 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 that the DNSPs annually set for customer use of the network. Network tariffs are typically constituted of two components.

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

Methodology

In assessing the network costs, we propose to continue the approach used in the DMO 2. The approach considers the representative retailer will pass through the applicable network tariffs to the customer. In determining the changes in network costs, we therefore propose to pass through changes in the applicable network tariffs outlined in Table 4.

Table 4 – Network tariffs (with network codes) to assess the change in network costs

Distribution zone	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

Network tariffs are approved by the AER through an annual pricing review. The network service provider proposes tariffs for the next financial year as part of an annual pricing proposal. The changes in tariffs are based on the annual change in revenue set in the relevant determination, as well as other factors.

DMO 2 consideration

Approved network tariffs were not available for the distribution zones at the time of publication of the DMO 2 Final Determination. In the absence of this information, we used the latest available indicative network tariffs to assess the forecast changes in network costs:

- In the Energex and SAPN regions, final network tariffs were not available due to ongoing network revenue resets. We used indicative tariffs for 2020-21 from the revised regulatory pricing proposal submitted by the network businesses as part of the 2020-25 revenue resets.
- In NSW, network businesses delayed submitting pricing proposals as they considered COVID-19 impacts on their forecasts.
    - For the Essential Energy zone, we used tariffs from its 2020-21 pricing proposal.

- The proposals submitted by Ausgrid and Endeavour were under further assessment when the DMO 2 final determination was published. We used the indicative tariffs for 2020-21 for these regions.

As noted earlier, some retailers have highlighted that the use of indicative tariffs in our DMO 2 calculations resulted in a smaller network component for those regions than if we had used final approved prices. This resulted in a DMO price that was lower than if we had used approved prices (generally by less than 2 per cent).

As noted earlier, we do not propose to make any adjustment to the DMO 3 price that retrospectively accounts for this difference. However, under the indexation approach the network component of the DMO will be indexed by the ratio of the estimate of network charges for 2021-22 (see below) to the estimate of network charges for 2020-21 used in DMO 2.

This provides a prospective correction for the difference between the indicative network charges and actual charges in 2020-21.

Proposed DMO 3 approach

For DMO 3, all the network distribution zones are within the regulatory control period, and are not undergoing a revenue reset.

To assess the change in network costs in 2021-22, we propose to consider the network tariffs proposed by the network business in their 2021-22 pricing proposals. Network businesses must submit these by 30 March each year.

If the AER has approved these proposals at the time of finalising the DMO calculations in late April, it will be straightforward to use the final published prices.

If the AER has not approved the prices, we propose using the submitted network pricing proposals, noting that these may change before they are finally approved.

If the pricing proposals are delayed due to some reason, and/or they are undergoing a more detailed assessment than usual, we would have regard to latest available indicative network tariffs.

To calculate DMO prices for the Draft Determination, we intend to use indicative network tariffs for 2021-22 submitted as part of the 2020-21 pricing proposals as the best available information at the time of publication of Draft Determination.

DMO determination date

Under the Regulations, AER is required to make its Final DMO determination by 1 May each year.

The AER is undertaking work to consider how the timing of network pricing proposals and how these can be better aligned with the DMO process.

We note the Australian Energy Council (AEC) is also considering this issue.

Stakeholder question:

8. Do you agree with our proposed approach to continue using the DMO 2 network costs methodology?

3.2.4 Retail costs and step changes

We identify other costs that make up the DMO price, apart from wholesale, environmental and network costs, as retail residual costs. This component includes costs that are incurred by retailers to acquire, service and retain customers, including meeting regulatory obligations.

For DMO 3 we propose applying forecast CPI to the retail costs component of the DMO annual bill. We will also consider whether it is reasonable to apply an adjustment to the DMO price to reflect any improvements in retailers' productivity over time.

We also employ a retail cost step change framework. This allows us to identify changes in retail costs that, in exceptional circumstances, are not accurately reflected by applying a general rate of change adjustment. We will consider any impacts of COVID-19 on retailer costs under this framework.

This section discusses our preliminary views on these issues.

Applying CPI to the retail costs component

For DMO 2 we adjusted retail costs by calculating DMO 1 residual costs and indexing these in line with forecast CPI.

For DMO 2, applying CPI resulted in an upward revision of the DMO 1 residual cost component by 1.75 per cent[36] to account for inflationary effects on costs, in line with Reserve Bank of Australia's (RBA) February 2020 CPI forecast. A majority of stakeholders supported this approach.

For DMO 3 we propose to maintain this approach by using the residual component identified in DMO 2 as the base and index by forecast CPI along with other adjustments to derive the residual component for DMO 3.

This has the benefit of maintaining the residual component of the DMO price at the same relative level. Our view is that this level of residual costs has met the DMO policy objectives as part of DMO 1 and 2, including enabling retailers to recover their efficient costs.

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

In the case where retail and other costs are materially impacted by exogenous factors such as new regulatory obligations, there is scope to apply step changes to the residual component. This is discussed further in the Step Changes section below.

Productivity adjustment

During the DMO 2 consultation, consumer groups disagreed with the application of CPI to forecast changes in residual costs, considering it does not reflect efficiency and productivity improvements.

- Energy Consumers Australia (ECA) considered:
  - retailers in a competitive market would be expected to become more efficient over time. It noted the ACCC found that between 2013-14 and 2017-18 retail costs per residential customer (averaged across the NEM) reduced year on year, and by $20 over the period.
  - changes coming into effect in December 2020 to remove the advance loss notification of a customer switch, and speeding up the transfer process, would further help to reduce retailer costs.
  - in light of the above points, there was a reasonable basis for reducing retailer costs, or at least holding them steady, rather than increasing them by CPI.[37]
- Similarly, Queensland Council of Social Services (QCOSS) and Etrog Consulting considered an annual CPI escalation of the retail component, without any consideration of lower retailer operating costs due to increased efficiency, was unjustifiable. It noted the AER had itself recently recognised increased productivity in the electricity distributors, which are not subject to competition.[38]

Productivity is a function of and measures how much output can be produced using a given quantity of inputs. In the retail electricity market, this relates to the cost of serving, acquiring and retaining customers, as well as other costs.

Publicly available information appears to support the view that improvements in retailers' efficiency are leading to reduced retail costs over time.

- AGL Energy's 2020 investor presentation showed an 8 per cent year-on-year decline in underlying net operating costs per customer service, a reduction of $12 per customer service between 2017-18 and 2019-20, with forecast further reductions into the future due to IT-related efficiencies

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

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

- Origin Energy's 2020 annual report noted that they are on track to reduce cost to serve by $100m from 2017-18 to 2020-21, with more customers shift to e-billing and digital engagement.
- The ACCC's Inquiry into the National Electricity Market – November 2019 Report also notes decline in retail and other costs, such as advertising and marketing, customer acquisition, on-boarding and retention, incurred by retailers. Between 2013-14 and 2018-19, an average decline in retail and other costs of $22 per customer was observed across the NEM.

Various regulators[39] and rule making authorities[40] have considered or applied a productivity factor when making pricing determinations or rules.

While no Australian energy regulators currently apply productivity in their retail price determinations, we note the Essential Services Commission of Victoria (ESCV) in its recent Victoria Default Offer 2021: Draft decision[41] seeks stakeholder views on introducing a productivity factor.

These organisations have considered data such as the historical productivity performance of a sector, Reserve Bank of Australia forecasts, Australian Bureau of Statistics' estimates on industry productivity, as well as publicly available information from retailers' annual reports and presentations.

A key point in these considerations of productivity is the regulators' access to cost information specifically relating to businesses' labour, operating and capital expenses, or benchmarking of fixed and variable costs.

Under the DMO methodology, we do not break down retailers' costs in this way.

In the DMO context, determining a productivity adjustment may imply a level of specificity in the calculation of the DMO with respect to retailers' costs that is not consistent with the DMOs' top-down methodology.

We will review information available to us to consider whether it is appropriate to include a productivity improvement factor in our DMO price setting to account for efficiency improvements.

This may include, for example, information that retailers provide to the ACCC as part of its inquiry into the National Electricity Market.

39 See Independent Pricing and Regulatory Tribunal New South Wales - Review of regulated retail prices and charges for electricity From 1 July 2013 to 30 June 2016, Queensland Competition Authority - Regulated retail electricity prices for 2016–17, Australian Energy Regulator - Forecasting productivity growth for electricity distributors.

40 Australian Energy Market Commission - Review into the use of total factor productivity for the determination of prices and revenues.

41 Essential Services Commission Victorian Default Offer 2021 Draft Decision, 15 September 2020.

We welcome stakeholder submissions on whether to apply a productivity factor and the form a productivity improvement factor should take, consistent with the DMO approach to not individually identify cost components.

We are also seeking stakeholder feedback on the available sources of information to determine an appropriate factor to apply, including examples from comparable sectors or jurisdictions.

Stakeholder questions:

9. Is it reasonable to apply a productivity factor to the DMO? What is the evidence retailers' costs are decreasing or increasing?
10. What form should any productivity adjustment take?

Step change framework

Our indexation methodology incorporates a step change framework to enable us to adjust the DMO price to account for material increases or decreases in retailers' costs to serve customers.

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
- lead to a material overall change in the retail costs of an efficient and prudent retailer.

  While we have not defined 'materiality' in this context, our intention is that incremental and minor cost changes would not meet the criteria for consideration. The DMO price is sufficiently high that costs of this nature will not impact on retailers' ability to recover their costs to service standing offer customers, and do not require a specific adjustment.
- not be compensated in other parts of our forecast or other DMO cost elements.

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 that the cost changes remain material for the relevant period.

For DMO 3, cost changes we are aware of that may meet these criteria for consideration include costs related to the impact of COVID-19 and the implementation of the Consumer Data Right. We discuss these issues below.

> **Stakeholder question:**
>
> 11. Do you agree with our proposed approach to continue using the DMO 2 step change framework?

COVID-19 impacts

DMO 2 consideration

Prior to determining the final prices for DMO 2, we consulted stakeholders on how we should take into account the impacts of COVID-19.

Stakeholders acknowledged the considerable uncertainty in forecasting the wholesale, environmental and network costs components at that time. There was no clear consensus on whether these types of costs would materially increase or decrease as a result of COVID-19.

The impact on retail costs was also unclear, with Government stimulus and other industry measures to potentially offset in part the negative impacts.

Most retailer submissions received as part of our DMO 2 COVID-19 consultation identified the major categories of retail costs that would likely increase:

- 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 has required some retailers to bolster onshore 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.

Based on the information available at the time, and the considerable uncertainty about specific impacts in the 2020-21 period, we did not make any adjustment to DMO prices in response to COVID-19.

Given the uncertainty presented by COVID-19, we committed to give further thought to a variation or ‘re-opener’ mechanism for the Regulations, should we need to adjust DMO prices part way through a DMO period to account for any material COVID-19 related cost changes.

We considered this issue, but ultimately determined not to proceed with it further. Our key reasons for this included:

- The DMO is a single year instrument. A re-opener would function to reset the price cap on standing offers for the remainder of the regulatory period only, resulting in limited benefit to consumers and retailers

- At the time we would need to make a decision about how to adjust the DMO under any reopener framework, there would still be significant uncertainty about the nature and magnitude of predicted cost impacts.

Proposed DMO 3 approach

We propose to consider any impacts of COVID-19 under the DMO retail costs step change framework.

Our view is that cost impacts identified in our COVID-19 consultation meet the criteria for consideration, in that they are exogenous, and a prudent retailer could not avoid them. In line with the framework, retailers would need to demonstrate any cost increases are materially higher than under a normal operating scenario.

The AER is continuously monitoring the impacts of COVID-19 on electricity consumers and retailers, including publishing weekly 'dashboard' data covering retailer debt levels (30, 60 and 90-day-old debt), customer payment plans and hardship arrangements.

There is a delay between when the customer accrues debt and the debt is recognised in the reporting as bad debt across the NEM jurisdictions. Taking January to March 2020 as the baseline representing the period prior to the onset of COVID-19; as at 31 August 2020[42], we observe:

- the number of residential customers with debts of 90 days or greater remain in line with the baseline period.
- the number of small business customers with debts of 90 days or greater is slightly above the baseline period.
- total debt accumulated for 90 days or greater in dollars for both residential and small business customers are elevated above the baseline.

We are also seeing increased provisions made by retailers for bad and doubtful debt, representing the business' expectation of money that it does not expect to collect from its customer, as reported in published annual reports and presentations. For example:

- AGL increased provision for bad and doubtful debt by $20m for the 2019-20 financial year to account for the expected impacts of COVID-19.
- Origin increased provision for bad and doubtful debt by $40m for the 2019-20 financial year to account for the expected impacts of COVID-19.

While the accounting treatment of bad and doubtful debt provisions results in a reduction of reported earnings, how much of that provision will be incurred as an expense is much more uncertain. That is because under Australian accounting standards[43], assessment of provision for bad and doubtful debts takes into account

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[42] See https://www.aer.gov.au/system/files/Retailer%20market%20data%20dashboard%20-%2031%20August%202020%20-%20COVID-19.pdf

[43] Australian Accounting Standards Board 9 – Financial Instruments

and considers regulatory and economic outlook, which would include factors such as government stimulus and income support, and the duration of pandemic lockdown measures.[44] These are subject to a high degree of uncertainty.

From those same published annual reports and presentations, reported retail cost to serve and customer acquisition and retention costs to 30 June 2020 are still decreasing, in line with observed trends in recent years. So far, from publicly available data and information, we have not observed material increases in cost to serve for retailers.

Noting the situation with COVID-19 is still fluid in nature, we will continue to closely monitor the impact of COVID-19 on retail costs, with a focus on bad and doubtful debts.

While we welcome retailer information about expected COVID-19 impacts in the DMO 3 period in response to this paper, we are likely to seek updated information during our Draft Determination stage around February/March 2021.

While retailers highlighted COVID-related factors that may increase their costs to serve, we are interested in stakeholders' views about whether any costs have decreased due to the pandemic. For example, have retailers' operating costs reduced due to staff working from home?

Stakeholder questions:

12. What will be the impact of COVID-19 on retailer costs in 2021-22? Are any retailer costs decreasing due to COVID-19?
13. What is the basis for estimating any cost impacts? Please provide information to assist with estimating cost changes associated with COVID-19.

Consumer Data Right

The Consumer Data Right (CDR) is a reform that gives Australian consumers greater control over their data.

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

Key elements of the rollout to the energy sector are AEMO developing a data 'gateway' system that will facilitate access to its central database of metering data. Retailers will

[44] Origin Energy Limited and Controlled Entities Appendix 4E Results for announcement to the market 30 June 2020, p. 31.

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

We expect that the new CDR obligations[45] for the energy sector will come into effect during the DMO 3 period. Additional rules to support the subsequent technical builds by stakeholders are also are likely to be made in the first half of 2021. The ACCC is responsible for developing these rules.

Retailers are unlikely to be able to accurately assess the costs of these builds until the rules and provision of the gateway are in place.

The ACCC recently consulted on and sought stakeholder views on the preliminary proposals for rules documented in the Energy rules framework.[46]

This consultation document also contained initial estimates of implementation and ongoing costs for energy data holders' technical build and ongoing operation to meet the CDR obligations. The estimated costs varied widely, between around $242,000 and $878,000 for one-off establishment, not accounting for other operational and back-office costs.

These estimates were prepared in 2018 and a number of retailers noted in their submissions that it is premature to provide cost estimates until the scope of the rules for the CDR in energy is determined

We welcome stakeholder submissions including cost information to assist us to assess the materiality of expenditure required to meet the CDR obligations.

Stakeholder questions:

14. What impact will meeting CDR obligations have on retailer costs in 2021-22? What is the basis for estimating any cost impacts? Please provide relevant cost information to assist with estimating cost changes associated with CDR.
15. Aside from CDR and COVID-19, are there other regulatory or operating environment changes that are likely to materially increase or decrease retailers' costs to serve customers in 2021-22?

[45] *Competition and Consumer (Consumer Data Right) Rules 2020.*

[46] https://www.accc.gov.au/focus-areas/consumer-data-right-cdr/cdr-in-the-energy-sector/energy-rules-framework-consultation

4 Model annual usage and TOU determination

Under Part 3 of the Regulations we are required to determine one 'broadly representative' annual supply amount for each customer type in each distribution region, from which a DMO price and reference price can be calculated.[47] In this chapter we refer to annual supply as annual 'usage'.

We must also determine the 'timing and pattern' of supply to residential customers.[48] The Regulations refer to annual supply and timing and pattern together as the 'model annual usage'.[49]

This chapter sets out our methodology for determining the DMO model annual usage for 2021-22, including how time of use (TOU) and solar tariff customers should be considered under the single DMO price.

4.1 Annual usage

For DMO 3 we intend to retain the same annual usage amounts adopted for DMO 2.

DMO 2 consideration

For DMO 1 we based annual usage for residential customers on network forecasts for 2019-20. Small business usage was based on information published by Energy Consumers Australia, which we considered to be the best information available.[50]

For DMO 2, we considered these usage amounts remained 'broadly representative'. Stakeholders also generally supported the usage amounts, noting they provided simplicity, consistency and comparability.[51]

Proposed DMO 3 approach

Our proposed position is to continue to apply the same annual usage amounts from DMO 1 and DMO 2 for residential and small business customers. Our key reasons for doing so are:

- we consider the amounts continue to meet the criteria of being 'broadly representative' of customer usage, and we have not received any new information since the last determination to suggest alternative figures are more representative

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

48 Regulations, s. 16(1)(a)(ii).

49 Regulations, s. 5.

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

51 Submissions to the DMO 2 Position Paper from AGL p. 5, Alinta Energy p. 2, Origin Energy p. 7, Ausgrid p. 6, EnergyAustralia p. 3.

- we note that small businesses are diverse in size and their use of energy. This means that the 20,000 kWh figure that we use at present may not be representative of the electricity use of many small businesses
- nevertheless we propose to retain the 20,000 kWh usage figure at this stage. This is because:
  - there is no alternative figure readily available
  - it would be necessary to recalculate DMO 1 and DMO 2 on the basis of the new usage assumption to determine the change in price from DMO 2 to DMO 3
  - there is no clear benefit to consumers from doing so.

While we consider the annual usage remains suitable, we are interested in stakeholders' views on this matter, including the benefits of alternative usage amounts, and data sources for small business customers.

Table 5 sets out the proposed annual usage amounts for DMO 3.

Table 5 – Proposed DMO 3 annual usage amounts

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

Source: Network distribution businesses' 2019-20 annual pricing proposals and the AER's 2017 Energy Consumption Benchmarks. Further detail described in DMO 1 Determination.

^ Source: Energy Consumers Australia, SME Retail tariff tracker.

Stakeholder question:

16. Do you agree we should retain the same annual usage amounts used for DMO 2? If not, what alternatives are more appropriate and what are their benefits?

4.2 Timing and pattern of supply

For DMO 3 we propose to:

- assume the same usage amount every day (with no variation for weekday, weekend or season), as in previous determinations
- use the same proportional allocations of annual CL usage across multiples CLs as in previous determinations
- adopt a usage profile for TOU tariff customers, providing a consistent basis for retailers to calculate compliant annual TOU prices.

Usage profiles

DMO 2 consideration

For DMO 2 we introduced a daily usage profile to enable retailers to ensure their TOU tariffs do not exceed the DMO price cap. The daily usage profile specified usage for each hour of the day over a 24 hour period. The same daily profile is applied to every day of the year. The profile provides the flexibility for retailers to determine how much usage to assign to their TOU tariff windows (peak, off-peak, shoulder).

The DMO 2 daily usage profile was based on household usage data collected as part of the AER's 2017 Energy Consumption Benchmark project.[52]

Most stakeholders supported the usage profile, noting the flexibility it provided retailers to set their own tariff windows was preferable to establishing fixed tariff windows. However, some stakeholders noted limitations with the profile, suggesting that the 2017 data used was outdated, and that the profile was overly simplistic and not representative of actual customer usage which differed, for example, on weekends compared to weekdays, and by season.

Proposed DMO 3 approach

We intend to update the usage profile and are investigating options to achieve this, including obtaining interval meter data from AEMO. Also, the AER has engaged a consultant to develop 2020 energy consumption benchmarks and we are considering whether data collected as part of that project may be used to update the profile.[53]

The data we obtain from either source is likely to enable us to develop profiles that are more representative of a current residential TOU customer in each region, as well more granular profiles. For example, the data may enable us to develop profiles that reflect different daily usage patterns for weekdays and weekend days, for each season.

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[52] AER, *Electricity bill benchmarks for residential customers 2017*: https://www.aer.gov.au/retail-markets/guidelines-reviews/electricity-and-gas-bill-benchmarks-for-residential-customers-2017

[53] AER, *Electricity and gas consumption benchmarks for residential customers 2020*: https://www.aer.gov.au/retail-markets/guidelines-reviews/electricity-and-gas-consumption-benchmarks-for-residential-customers-2020

More detailed or granular profiles would provide a better basis for calculating annual prices for TOU offers that are more representative of a typical TOU customer in a distribution region.

However, any increase in granularity is likely to add considerable complexity to the process of applying the profile to calculate an annual price. We are aware recent ACCC compliance monitoring indicates some retailers have experienced difficulty in applying the current simplified daily profile. More complex profiles could increase the possibility of retailer error, and require more retailer effort to ensure prices are compliant with the DMO price cap.

Therefore, in considering whether to increase the level of detail in the daily profile, we also need to determine whether the benefit in doing so outweighs the cost of the additional complexity.

We have set out three possible options for usage profiles below. They move from the simplest (1) to the most detailed (3).

1. **One-day profile – a single day, with usage specified at 30 minute or 1 hour intervals**

   This profile would be an updated version of the DMO 2 profile based on current data. The pattern of use would be the same across each day of the year, but could also be broken down into half hourly rather than hourly intervals. This is the simplest profile to apply of the three options listed here and is our preferred option.

2. **Two-day profile, comprising a weekday and weekend day pattern, with usage specified at 30 minute or 1 hour intervals.**

   This profile would assume the same pattern of use on every weekday and weekend day of the year without any seasonal variation.

3. **Eight-day profile, comprising a weekday and weekend day pattern for spring, summer, autumn and winter, with usage specified at 30 minute or 1 hour intervals.**

   This would be the most complex profile, requiring retailers to determine usage on weekdays and weekend days for each season.

Consistent with the Regulations, we consider that the purpose of the profile is to broadly represent customer usage. Our view is a single daily profile (option one) adequately meets this objective, while offering a significant improvement on the DMO 2 profile, being based on current smart meter data.

In addition, we are aware of the newly introduced ‘solar sponge’ TOU CL tariff in South Australia.

Where CL tariffs generally apply over night during off-peak periods, the SAPN TOU CL tariff includes a lower ‘solar sponge’ rate during the middle of the day to incentivise energy usage during periods of high solar export to the grid.

Given the distinctive nature of this tariff we consider it may be appropriate to develop a usage profile for this particular tariff. We are investigating data sources that would enable us to develop a profile for the CL component of this tariff.

Stakeholder question:

17. What is the appropriate level of detail to include in the daily usage profile? What are the risks and benefits of a simple TOU profile compared to a detailed one?

4.3 Costs to serve TOU and solar customers

The Regulations do not enable us to determine separate DMO prices for TOU and solar tariffs. Therefore, we need to consider how to account for any additional costs retailers may incur to supply customers on either of these tariff types in the single DMO price applying to all residential customers and small business customers.

DMO 2 consideration

During our DMO 2 determination process some stakeholders highlighted the increasing penetration of advanced meters in DMO jurisdictions, and suggested the DMO price should be adjusted to reflect higher metering costs incurred by retailers for advanced meters.

The Regulations do not provide for us to make a separate annual price or model annual usage determination for TOU customers. Our DMO 2 Final Determination therefore considered how we should take into account any differences in costs to serve TOU customers in the single DMO price.

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

- the DMO price is sufficient to enable recovery of efficient costs for TOU customers, being above the median TOU market offer, our proxy for a retailer's efficient costs
- the relatively small number of customers on TOU standing offer tariffs (around 38,000 in DMO jurisdictions) would mean any cost differences, where they exist, would have limited impact on retailers' revenues.

- in regard to advanced meters specifically, we noted that the Regulations require us to only consider annual or ongoing costs, not one-off fees or a fee for a service provided on request.[54]

Our consideration of advance meter costs included:

- the average annual cost of an advanced meter is higher than a conventional meter. The QCA final report found a typical residential advanced meter costs approximately $118 per meter per annum in South East Queensland, though actual costs vary by retailer.[55] They suggested an accumulation meter costs around $36 per year
- retailers recover the costs of advanced meters in different ways. The QCA noted most retailers do not currently charge customers individually for their particular metering costs. Due to the relatively small number of advanced meters installed, retailers either absorb the costs, or spread them across all customers[56]
- retailers avoid some costs when a customer has an advanced meter installed. These include meter reading costs (as advanced meters can be read remotely) and the costs that would have been incurred had an accumulation meter been installed.

Our analysis conducted in October 2019 indicated there was a significant margin between the median market offer (our proxy for retailers' efficient costs) and the DMO price enabling retailers to recover any additional costs they may incur to supply customers on these tariff types.[57]

Based on the above considerations, we determined not to make any adjustment to the DMO price to account for any additional costs retailers face for TOU and/or advanced meter customers.

Proposed DMO 3 approach

Since making our determination we have not received any new information to suggest retailers are not able to recover their costs to supply customers on TOU tariff types.

We have continued to monitor these costs by comparing the relative cost of supplying TOU and flat rate customers.

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

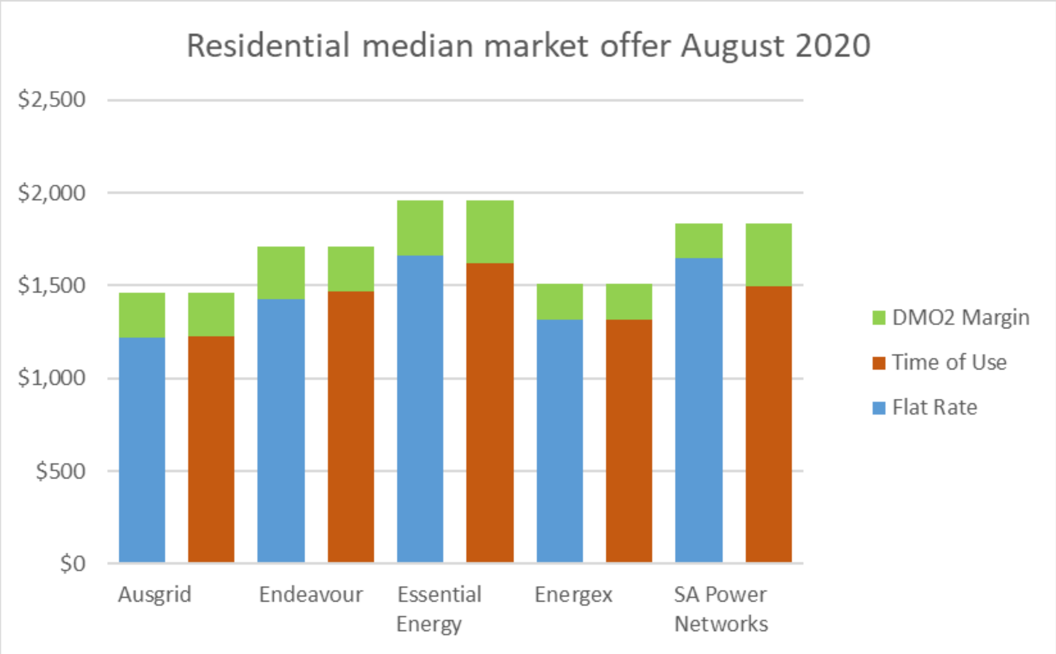
55 QCA, *Ministerial advice: Benefits of advanced digital metering*, September 2019, p. 3; ACIL Allen, *Report to the Queensland Competition Authority, Advanced digital meters, estimating the potential net benefits final report*, 2 September 2019, p. 16.

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

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

Table 6 shows a comparison of the August 2020 median market offer for flat rate customers and the DMO price, and the median market TOU offer compared to the DMO price.

Table 6 – TOU and Flat rate median market offers compared to DMO 2 prices



The analysis shows the price differences between TOU median market offers and the DMO 2 price is similar to, and in some cases greater than, the difference between flat rate median market offers and the DMO, depending on the region.

This suggests that our assumptions that retailers are able to recover costs to supply customers on these tariff types still holds for the DMO 2.

We note the advanced meter roll-out is continuing in DMO regions, and customers on non-TOU tariffs may have advanced meters. We will consider information submitted by stakeholders about these costs.

A further challenge in increasing the DMO to reflect advanced metering costs is that any DMO increase would apply to flat rate customers, who make up the majority of standing offer customers, though the higher costs are not incurred in relation to them. We will need to consider the equity of this cross-subsidy in the context of the DMO objective to prevent excessive standing offer prices for standing offer customers.

Stakeholder questions:

18. Do you agree our DMO 2 approach to advanced meter costs remains appropriate for DMO 3?

19. If not, what is the evidence that advanced metering costs are impacting retailers' abilities to recover their costs to serve standing offer customers?
20. Is it reasonable to increase the DMO price for flat rate standing offer customers to take account of the higher costs of advanced metering?

Solar Customers

In our DMO 2 determination we acknowledged that while retailers may incur some moderate additional costs to serve solar customers, the DMO price was sufficient in each region and did not affect retailers' abilities to recover costs. Our position was to not adjust the DMO price to take solar specific costs into account.

As discussed previously, we consider that the question of any additional costs to supply solar customers would be more relevant if there were a separate DMO price applying to these customers.

In the absence of a separate price and given these customers constitute a smaller proportion of customers compared with non-solar customers, we do not consider it appropriate to provide any additional allowance within the single DMO price for the separate costs arising from supplying solar customers.

While we consider this approach appropriate, we are interested in stakeholder views on the reasons for and benefits of any alternative approach.

Stakeholder question:

21. Do you agree our DMO 2 approach to costs to supply solar customers remains reasonable?

Appendices

Appendix A – Stakeholder questions

Appendix B – Market offer analysis for each distribution region

A Stakeholder questions

In responding to this consultation please respond to the questions outlined in the table below.

Stakeholder Questions
1. Do you agree with the principle that forecasts and assumptions from previous DMO determinations should not be retrospectively amended to reflect actual information?
2. Does our assumption of a risk averse retailer building their hedge book from the time of the first trade recorded by ASX Energy remain appropriate, or is a shorter period justified? What is an appropriate period and why?
3. Does the Consultant's 95th percentile estimate remain appropriate, given the hedging strategy? What alternative percentile could be applied and what would the justification be?
4. Do you agree with our proposed approach to assign ancillary service charges to each state, rather than smeared across the DMO jurisdictions?
5. What are the implications of differentiating between residential and small business load profiles to forecast wholesale costs?
6. Do you agree with our proposed approach to continue using the DMO 2 wholesale energy cost forecasting methodology?
7. Do you agree with our proposed approach to continue using the DMO 2 environmental costs methodology?
8. Do you agree with our proposed approach to continue using the DMO 2 network costs methodology?
9. Is it reasonable to apply a productivity factor to the DMO? What is the evidence retailers' costs are decreasing or increasing?
10. What form should any productivity adjustment take?
11. Do you agree with our proposed approach to continue using the DMO 2 step change framework?
12. What will be the impact of COVID-19 on retailer costs in 2021-22? Are any retailer costs decreasing due to COVID-19?
13. What is the basis for estimating any cost impacts? Please provide information to assist with estimating cost changes associated with COVID-19.
14. What impact will meeting CDR obligations have on retailer costs in 2021-22? What is the basis for estimating any cost impacts? Please provide

relevant cost information to assist with estimating cost changes associated with CDR.

15. Aside from CDR and COVID-19, are there other regulatory or operating environment changes that are likely to materially increase or decrease retailers' costs to serve customers in 2021-22?
16. Do you agree we should we retain the same annual usage amounts used for DMO 2? If not, what alternatives are more appropriate and what are their benefits?
17. What is the appropriate level of detail to include in the daily usage profile? What are the risks and benefits of a simple TOU profile compared to a detailed one?
18. Do you agree our DMO 2 approach to advanced meter costs remains appropriate for DMO 3?
19. If not, what is the evidence that advanced metering costs are impacting retailers' abilities to recover their costs to serve standing offer customers?
20. Is it reasonable to increase the DMO price for flat rate standing offer customers to take account of the higher costs of advanced metering?
21. Do you agree our DMO 2 approach to costs to supply solar customers remains reasonable?

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 five 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
- 31 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.

Figures B.1 to B.15 below show these movements in graph form. These fifteen charts show the offers from Energy Made Easy (EME) for the three customer types and five distribution zones.

Changes in market offer prices in Ausgrid's region

Figure B1: Residential flat rate tariff

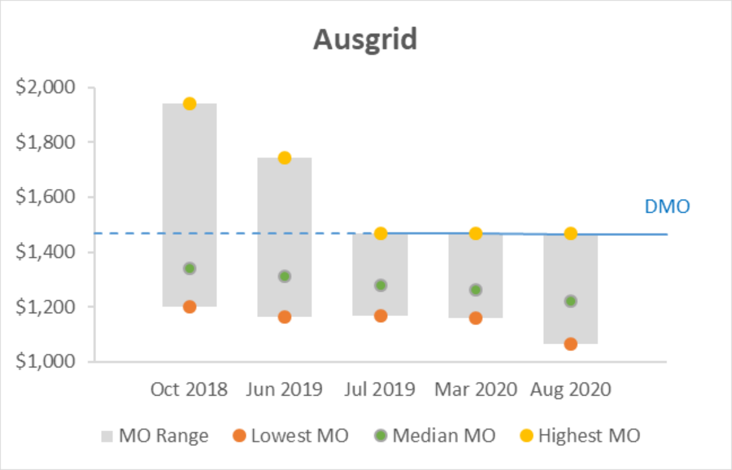


Figure B2: Residential flat rate tariff with controlled load

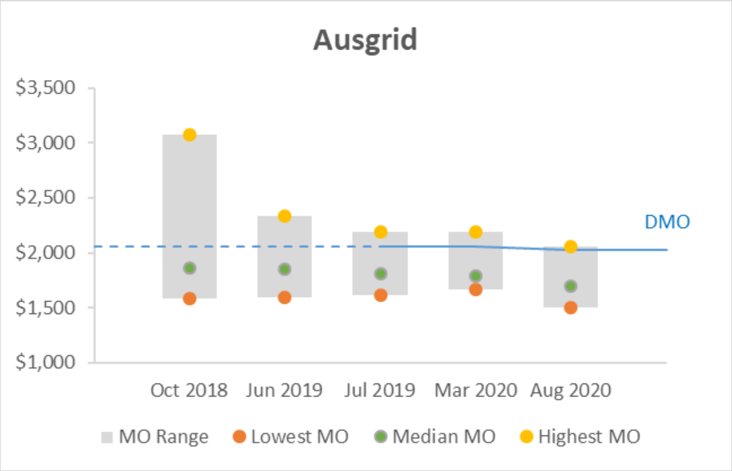
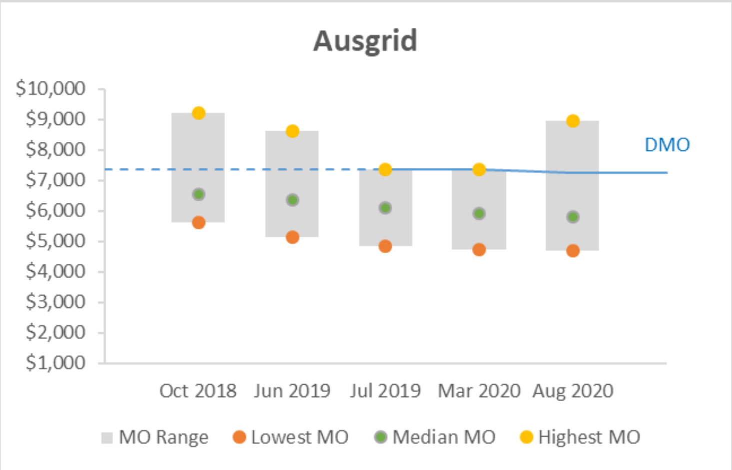


Figure B3: Small business flat rate tariff



Changes in market offer prices in Endeavour Energy's region

Figure B4: Residential flat rate tariff

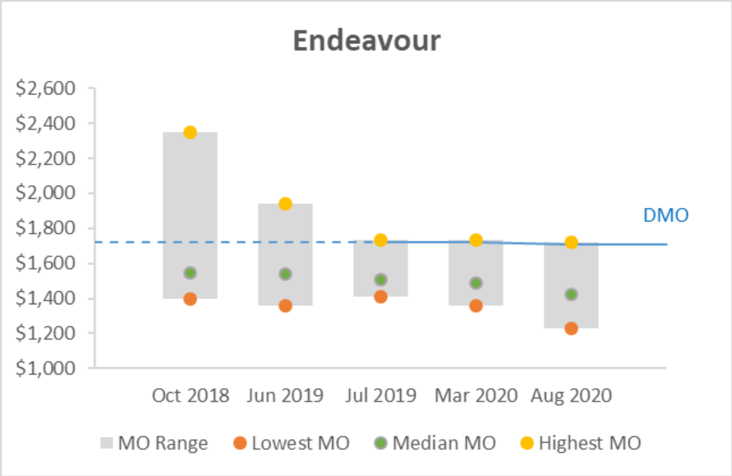


Figure B5: Residential flat rate tariff with controlled load

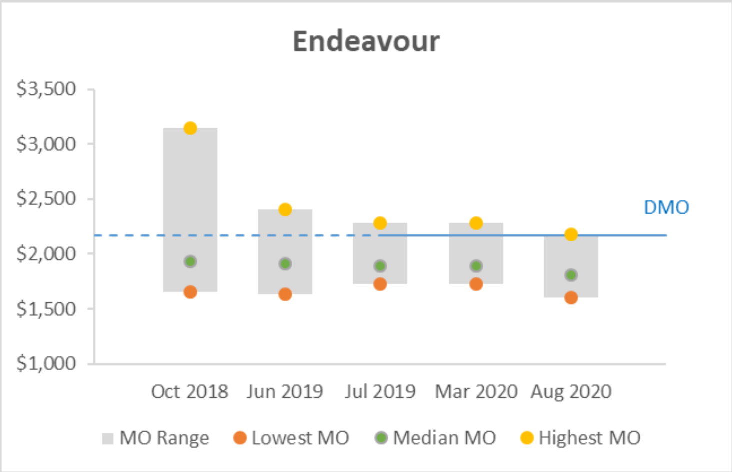
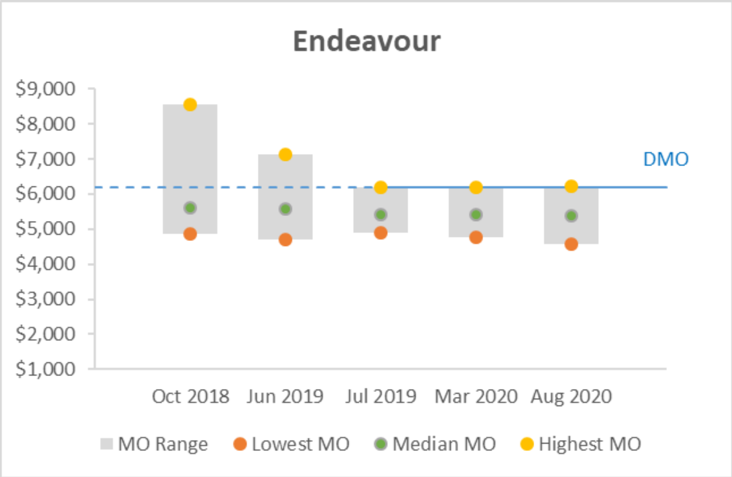


Figure B6: Small business flat rate tariff



Changes in market offer prices in Essential Energy's region

Figure B7: Residential flat rate tariff

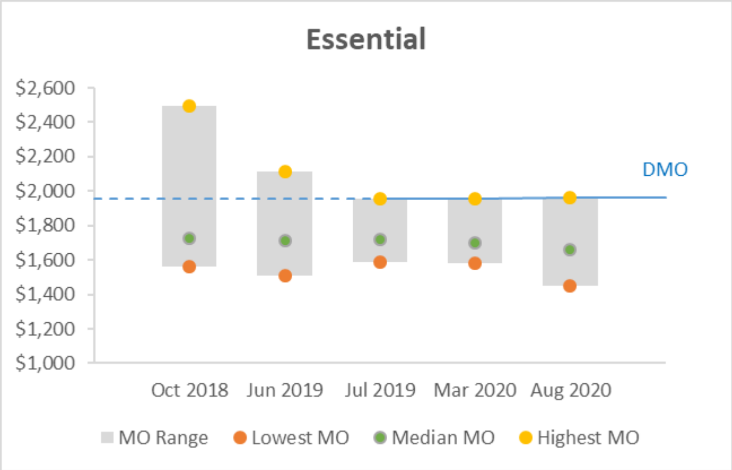


Figure B8: Residential flat rate tariff with controlled load

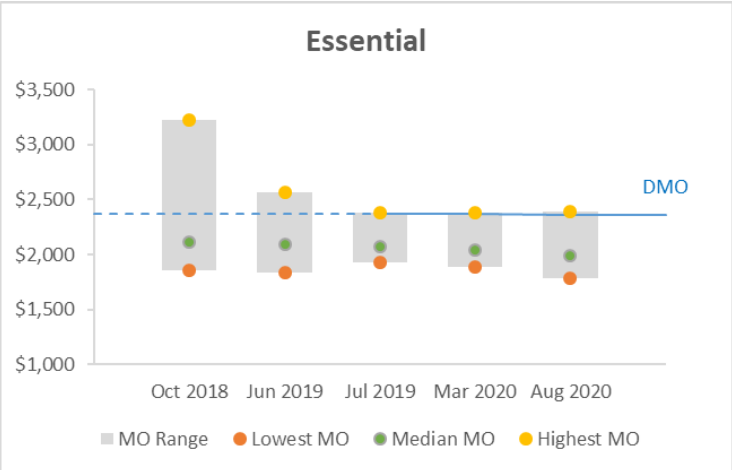
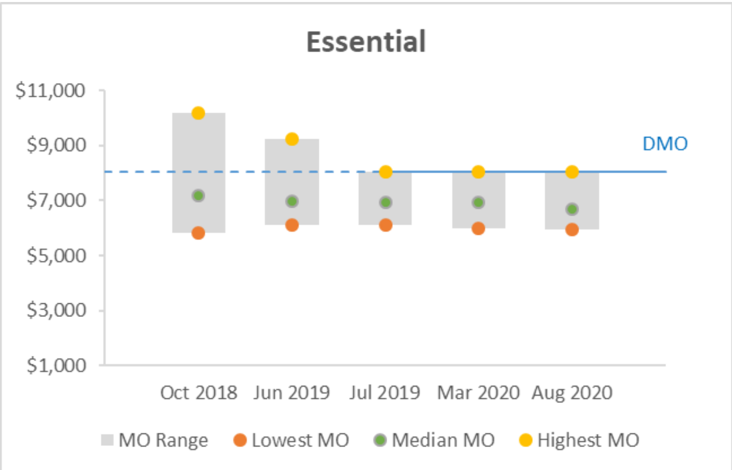


Figure B9: Small business flat rate tariff



Changes in market offer prices in Energex's region

Figure B10: Residential flat rate tariff

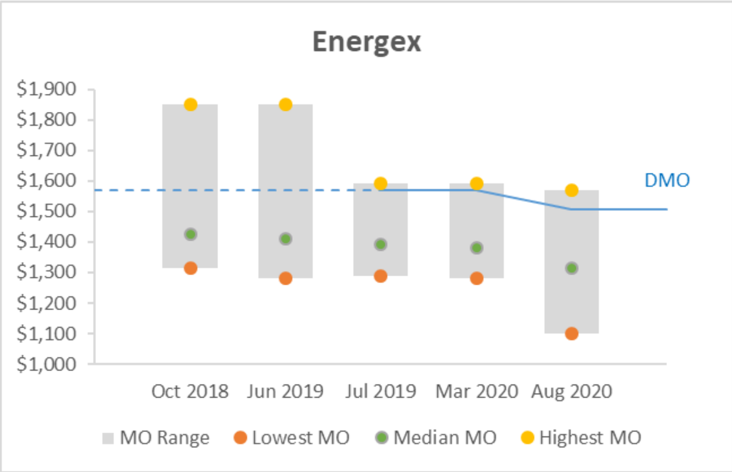


Figure B11: Residential flat rate tariff with controlled load

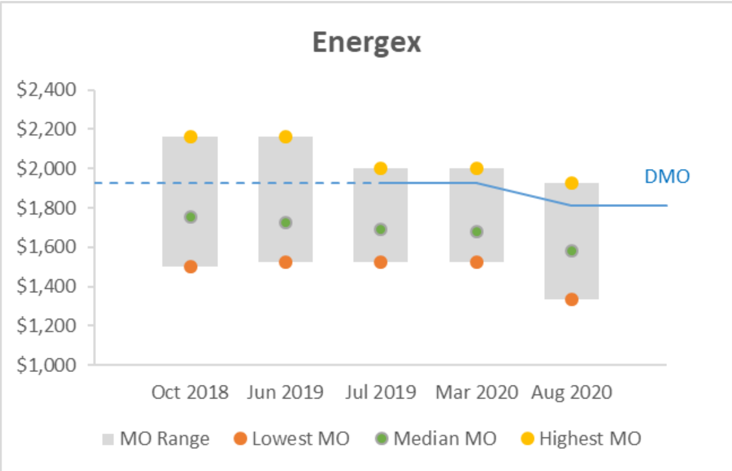
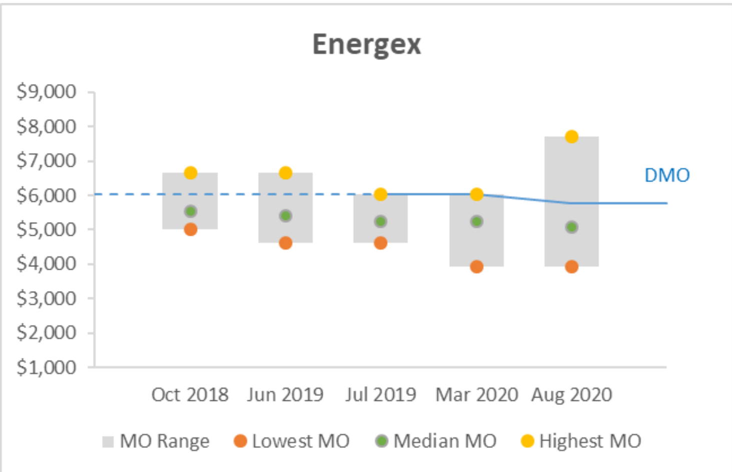


Figure B12: Small business flat rate tariff



Changes in market offer prices in SAPN's region

Figure B13: Residential flat rate tariff

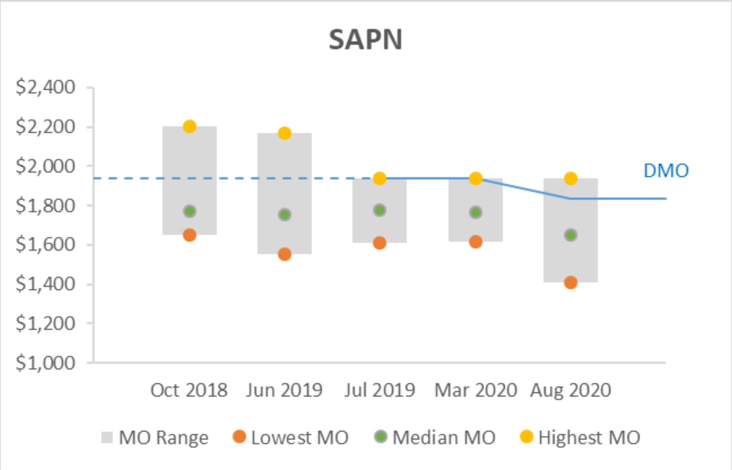


Figure B14: Residential flat rate tariff with controlled load

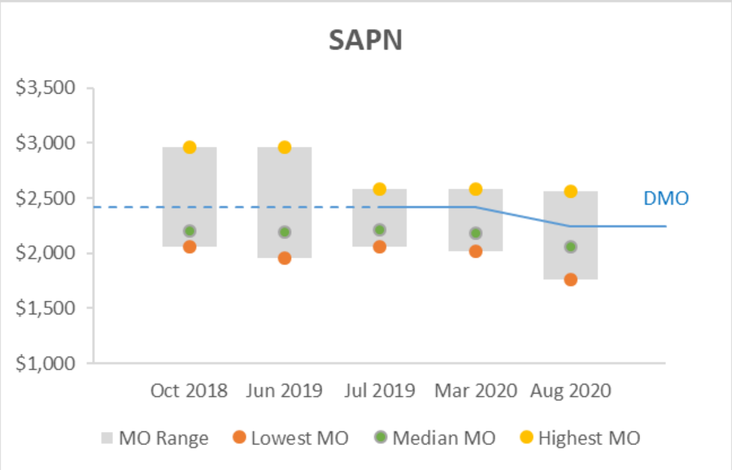
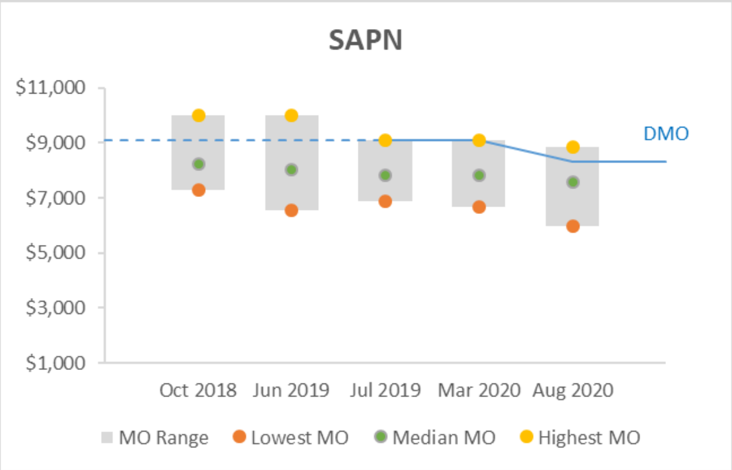


Figure B15: Small business flat rate tariff



From March 2020 to August 2020, the median market offers decreased in all distribution regions for all customer types. For residential customers the median market offer reduced between 3.2 (Ausgrid) and 6.6 per cent (SAPN), and between 2.7 (Essential) and 5.9 per cent (Energex) for customers with CL. The median market offers for small business customers reduced between 0.5 (Endeavour) and 3.5 per cent (SAPN).

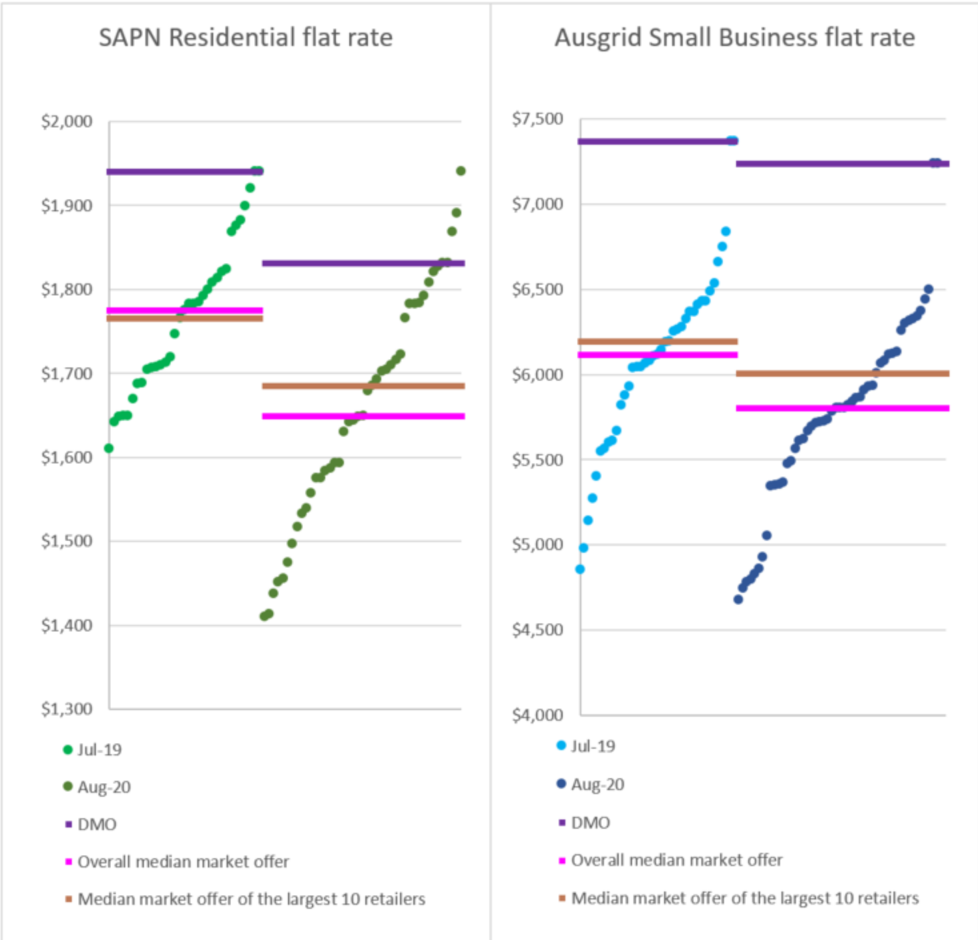
These reductions in the median market prices have generally been larger than the change from DMO 1 to DMO 2, which were either smaller decreases or marginal increases, depending on the region and customer type. This has had the result of increasing the margin between the DMO and the median market offer.

Across this same time period, the lowest market offers decreased for all customer types in all regions, with the exception of small business customers in Energex's region, which had no price movement. We observed some significant decreases for all customer types in some regions. For residential customers, the lowest market offer reduced between 8.1 (Essential) and 14.4 per cent (Energex) and between 5.8 (Essential) and 13 per cent (SAPN) for customers with controlled loads. The lowest market offers for small business customers reduced between 0.8 (Essential) and 10.5 per cent (SAPN).

These large decreases in the lowest market offers are part of a trend where small retailers, some of which are new entrants, have aggressively priced 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 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 offers, similar in breadth to June 2019, prior to the introduction of DMO.

We have also examined the median market offer based on the largest 10 retailers by market share that together supply electricity to 94 per cent of residential and small business customers. The median offers among these retailers have not decreased to the same extent as the overall median market offer for residential customers and small business customers in some regions and more closely align with the change from DMO 1 to DMO 2. Figures B16 and B17 demonstrate some examples of these pricing behaviours and the different movements of the median market offers in July 2019 and August 2020.

Figure B16 & B17: Movements in pricing behaviour



Note: two small business offers in Ausgrid's region were priced significantly above the DMO and are not shown on this chart.