Default Market Offer prices

Options Paper on the methodology to be adopted for the 2022-23 determination (and subsequent years)

25 October 2021

AUSTRALIAN ENERGY REGULATOR

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AER reference: 64687

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Invitation for submissions

Interested parties are invited to make submissions on this Options Paper by Friday 19 November 2021.

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

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

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

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

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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
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
DMO 4	Default market offer determination for 2022–23
ECA	Energy Consumers Australia
EME	Energy Made Easy
ESCV	Essential Services Commission Victoria
EWOSA	Energy and Water Ombudsman South Australia
FiT	Feed-in tariff
ICRC	Independent Competition and Regulatory Commission
kW	Kilowatts
kWh	Kilowatt hours
kVa	Kilovolt amperes
LAR	Local area retailer
LRET	Large-scale Renewable Energy Target

Shortened form	Extended form
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
RET	Renewable Energy Target
RPP	Renewable power percentage
SAPN	SA Power Network
SME	Small and medium-sized business customers (enterprises)
SO	Standing offer
SRES	Small-scale Renewable Energy Scheme
STP	Small-scale technology percentage
TOU	Time of use
TUOS	Transmission use of system
UTP	(Queensland) Uniform tariff policy
VDO	Victorian Default Offer

1 Summary

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

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

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

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

The Regulations require that we must have regard to a range of factors in setting the annual DMO price. These include ensuring that retailers can recover the costs they incur to serve customers and make a reasonable profit. In setting a price that protects standing offer customers from unjustifiably high prices, we must also ensure that retailers have incentives to compete, innovate and invest.

This Options Paper is the first step in our process to determine DMO prices for 2022–23. This is the fourth time we will determine DMO prices. As such we refer to the 2022–23 DMO throughout this Options Paper as 'DMO 4'.

1.1 DMO methodology review

During the DMO 3 consultation, we committed to undertake a holistic review of our methodology for setting DMO prices as part of our DMO 4 determination, with any changes to the methodology to be implemented in the DMO 4 prices.

We noted that after 3 years of DMO decisions, our DMO 4 review would be important to ensure our overarching approach, and the assumptions that underpin our methodology, remain appropriate to meet the policy objectives and continue to meet stakeholder expectations.

This Options Paper sets out the issues we are considering as part of the methodology review.

We are seeking stakeholder feedback on a wide range of options, covering almost all aspects of the DMO. These include:

- Our approach to retail costs and the way they are adjusted.

- Our approach to forecasting wholesale electricity costs – in particular, what ‘representative retailer’ we should seek to replicate, and how this can be reflected in our methodology.
- How we should treat costs to serve customers with advanced meters, or on time of use (TOU) tariffs.
- Our ‘model annual usage’ determination, including ensuring our residential and small business annual usage benchmarks are ‘broadly representative’.

To provide consistency and certainty for stakeholders, any changes to the methodology should remain in place for a reasonable period. This paper sets out some considerations about the longevity of our approach.

Separately, the Commonwealth Department of Industry, Science, Environment and Resources (DISER) has commenced its review of the DMO Regulations. We are working with DISER to align our respective reviews as far as possible, to avoid duplication and minimise impact on stakeholders.

1.2 Next steps

Table 1.1 outlines our timetable for the development of DMO 4 prices.

Table 1.1: DMO 4 timetable

Milestone	Date
Publish Options Paper	25 October 2021
Online stakeholder forum	10 November 2021
Submissions due	19 November 2021
Publish Draft Determination	February 2022
Submissions due	March 2022
Publish Final Determination	May 2022
DMO 4 in force	1 July 2022

2 Background

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

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

We protect the interests of household and small business consumers by enforcing the National Energy Retail Law (NERL). Our retail energy market functions cover NSW, SA, Tasmania, the Australian Capital Territory (ACT) and Queensland.

Our objectives include:

- Protecting vulnerable consumers, while enabling consumers to participate in energy markets; and
- effectively regulating competitive markets primarily through monitoring and reporting, and enforcement and compliance.

Under the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Regulations), our role is to set the DMO price each year for regions where there is no retail price regulation: NSW, south-east Queensland and SA.

2.1 Policy context for the DMO

In the final report of its 2018 Retail Electricity Pricing Inquiry (REPI), the Australian Competition and Consumer Commission (ACCC) noted electricity standing offer prices were unjustifiably high.[2]

The ACCC found that standing offers, originally intended as a default protection for consumers who were not engaged in the market, were no longer working as intended and were:

- Being used by retailers as a high priced benchmark from which their advertised market offers were derived. This created significant complexity in comparing deals.
- Causing financial harm to standing offer customers, who were often not engaged in the market for a range of reasons.

To address these concerns the ACCC recommended the introduction of a DMO to cap the amount that retailers can charge residential and small business standing offer customers. It recommended the AER set the maximum price for the default offer in jurisdictions where there is no retail price regulation.

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2 ACCC, *Retail Electricity Pricing Inquiry, Final report,* 2018.

The Commonwealth Government accepted the recommendation and introduced regulations giving effect to the DMO from 1 July 2019. The legislative framework for determining DMO prices is contained in the Regulations.[3]

The ACCC stated 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 DMO price should be set. It also established the policy objectives that the DMO should:

- reduce unjustifiably high standing offer prices and continue to protect consumers from unreasonable prices;
- allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention; and
- enable competition, innovation and investment by retailers, and retain incentives for consumers to engage in the market.

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

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

For our DMO 2 and 3 determinations, 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 a consumer price index (CPI) to the remaining retail cost ‘residual’. We referred to this approach as ‘indexation’.

In each determination, our analysis has shown the DMO price continued to enable retailers to offer prices that facilitate competition and provide incentives for customers to switch to a market offer.

Continuing to balance the policy objectives remains our primary consideration as we commence the process of determining DMO 4 prices.

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

4 ACCC, *AER Default market Offer, Submissions to the Draft Determination*, 20 March, pp.1–2.

Customers on standing offers

The majority of customers on standing offers are served by 'Tier One' retailers – AGL Energy, EnergyAustralia and Origin Energy.[5] The Tier One retailers are otherwise referred to as Local Area Retailers, who acquired the customer base of a particular region at the time of retail market privatisation.[6]

The Australian Energy Market Commission (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' (for example, if a poor credit history means other retailers will not supply them)[7]
- have moved into a premises and receive supply from the existing retailer supplying the premises but are yet to make contact with the retailer[8]
- have defaulted to a standing offer following the expiry of a market contract.[9]

Table 2.1 sets out the number and proportions of customers on standing offers for DMO areas in the third quarter of 2020–21. Fewer than 2% of customers on retailer hardship arrangements are on standing offers.[10]

We note that while the proportion of customers on standing offers has fluctuated in recent quarters, the long-run trend is steady decline. Appendix C shows the change in the proportion of standing offer customers since 2015.

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

6 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 Energy and Origin Energy acquired the Energex customer base, Origin Energy is the formally designated Local Area Retailer for the Energex region under the NERL.

7 Unlike other retailers, under s. 22 of the NERL Local Area Retailers cannot refuse to supply customers.

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

9 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 ongoing market contracts where discounts have expired. In practice these customers may be paying a retailer's standing offer prices. We do not know how many customers may be in this situation.

10 AER Retail Market Performance update, Quarter 3 2020–21.

Table 2.1: Customers on standing offers in DMO areas

	Residential customers (number and %)	Small business customers (number and %)
NSW	360,671 (10.9%)	73,236 (21.8%)
South-east Queensland Figures extrapolated from all Queensland by excluding Ergon customers. We note other retailers have customers in regional Queensland so figure is approximate	170,746 (11.8%)	25,709 (23.0%)
SA	67,064 (8.4%)	13,634 (15.5%)
Total standing offer customers	**598,481**	**112,579**

Source: AER Retail Market Performance update, Quarter 3 2020–21.

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 confer 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 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:

- NSW – Ausgrid, Essential Energy and Endeavour Energy

[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.

- SA – SA Power Networks (SAPN)
- south-east Queensland – Energex.

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

- *Residential customers* – on flat rate or TOU tariffs who use electricity mainly for personal, household or domestic use, and whose prices do not include a controlled load tariff. A controlled load 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 controlled load* – on flat rate or TOU tariffs who use electricity mainly for personal, household or domestic use, and whose prices include a controlled load tariff.
- *Small business customers* – on flat rate tariffs with no controlled load, and who use less than 100 megawatt hours (MWh) per year.

Each category includes customers with solar tariffs.

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

- tariffs with a demand charge
- small business controlled load and TOU tariffs
- tariffs offered 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 that require:

- standing offer prices for small customers must not exceed a price determined by the AER[17]

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15 Regulations, s. 16(4).

16 AER, Final determination, default market offer prices 2019–20, p. 27 – 29; AER, Final determination, default market offer prices 2020–21, p. 75 – 77.

17 Regulations s. 10.

- 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 provision is the responsibility of the ACCC.

2.3 DISER’s DMO Regulations review and our process

The Commonwealth Department of Industry, Science, Environment and Resources (DISER) recently commenced its 2 year post-implementation review of the DMO Regulations, with the release of a Consultation Paper.[20]

DISER’s review is examining:

- the key consumer outcomes resulting from the introduction of the DMO and Reference Price, including public awareness, understanding and perceptions of the DMO and Reference Price
- the impact of the Regulations’ introduction on electricity prices, including changes to standing offers, market offers and conditional discounting
- the operation of the Regulations, including experience with its implementation to date and how its ongoing operation could be improved.

DISER intends that any regulatory changes resulting from its review will be finalised by the time of our DMO 4 Determination.

The Consultation Paper seeks stakeholder views on a small number of questions that may be relevant to our review:

- Whether the Code appropriately covered all customer types that should be able to access the protections provided by the Default Market Offer, for example embedded network, demand tariff or prepayment meter customers.
- Whether the AER has been provided with the appropriate functions for the implementation of the Code.
- Whether the DMO Determination timeframes could be better aligned with the most recent network pricing determinations.

If the Regulations were expanded to cover new customer categories, such as embedded network customers, demand tariff or pre-payment meter customers, our

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[18] Regulations s. 12

[19] Regulations s. 14.

[20] https://consult.industry.gov.au/energy/review-of-default-market-offer-and-reference-price/

consideration of these customers in setting the annual price and model annual usage would depend on the final form of any amendments to the Regulations. In particular, whether they were included as a new customer ‘type’ or were included within the existing 3 current types (residential, residential with controlled load and small business).

Given the timing of the DISER review, this Options Paper sets out some of our initial consideration of these issues. We intend to discuss these issues in greater detail in our Draft Determination. At that stage, our views will be informed by stakeholder feedback to DISER’s review, and the proposed regulatory amendments set out in DISER’s Directions paper.

A later DMO final date would not have significant impacts for our DMO process and would increase the likelihood that we would be able to use approved network prices in non-network reset years. On this basis we support such a change. We discuss these issues further in relation to Network cost considerations (chapter 7).

We note that the DISER’s review does not specifically consider any changes to the DMO objectives. In this Options Paper, our assumption in discussing the DMO objectives is that these will not change as part of DISER’s review.

3 Context for this review

Australian energy regulators have generally adopted retail price setting approaches based on an assessment of retailers' costs. Characteristics of this approach – sometimes referred to as a 'bottom up' approach – include:

- Determining the 'efficient' costs of a typical retailer. In general terms, this can be understood as a nominal price at which a typical retailer can recover all their reasonable costs to serve customers – including wholesale electricity costs, network costs, environment costs and retail costs.
- Setting a retail margin, often by comparing the costs and margins of a number of retailers and establishing a benchmark, such as an average or median.

In contrast, our DMO determinations to date have not used a bottom up approach. Given the DMO is not intended be the lowest price in the market, our view in setting the DMO 1 price, and in subsequent determinations, was that this level of cost detail was not necessary or proportionate to meet the policy objectives.

This section discusses the price setting approaches we have adopted in our previous determinations to provide context for the methodology options set out later in this paper.

3.1 DMO 1 price setting approach

We determined the DMO 1 price using a methodology based on retailers' observed market and standing offer prices.

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

We chose these upper and lower points because:

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

Our approach did not involve a bottom-up calculation of cost components. However, in determining where to set the price, we considered how different cost components would contribute to the chosen price and estimated how these were expected to change in 2019–20.

Our final position was that, taking these expected changes into account, the 50th percentile point in the median market offer/median standing offer range was the appropriate price point that met the relevant policy objectives for the DMO and criteria set out in the Regulations.

3.2 DMO 2 and 3 price setting 'indexation' approach

Our goal for DMO 2 was to preserve the outcomes we achieved in DMO 1, which prevented unjustifiably high prices while enabling retailers to compete effectively below the cap.

To achieve this, we carried the price forward into the DMO 2 determination period but adjusted it to account for forecast changes in retailers' underlying costs to supply. This process involved 2 steps.

First, we retrospectively estimated wholesale energy, network, and environment cost components of the DMO 1 price. The remaining value between these costs and the DMO price was a 'residual' component, which nominally included retailers' operating costs and profit margin. We did not separately specify the costs for each of these sub-components, but considered the residual was large enough to achieve the DMO objectives.

Secondly, to set a forward looking DMO 2 price that reasonably reflected retailers' costs to supply customers, as well as balance the DMO objectives, we:

- estimated the changes in retailers' annual wholesale, environmental and network costs for the DMO 2 period and used these to adjust each component from the DMO 1 level. We noted these costs would need to be adjusted annually as they are subject to both regular and significant changes beyond the reasonable control of retailers.
- applied forecast CPI to the residual component.

We noted that applying CPI to the residual component, in exceptional circumstances, may not capture material and unavoidable changes in costs caused by major and unavoidable changes in the energy retail landscape, such as costs to implement new regulations. We developed a step change framework to provide a mechanism to pass through such costs.

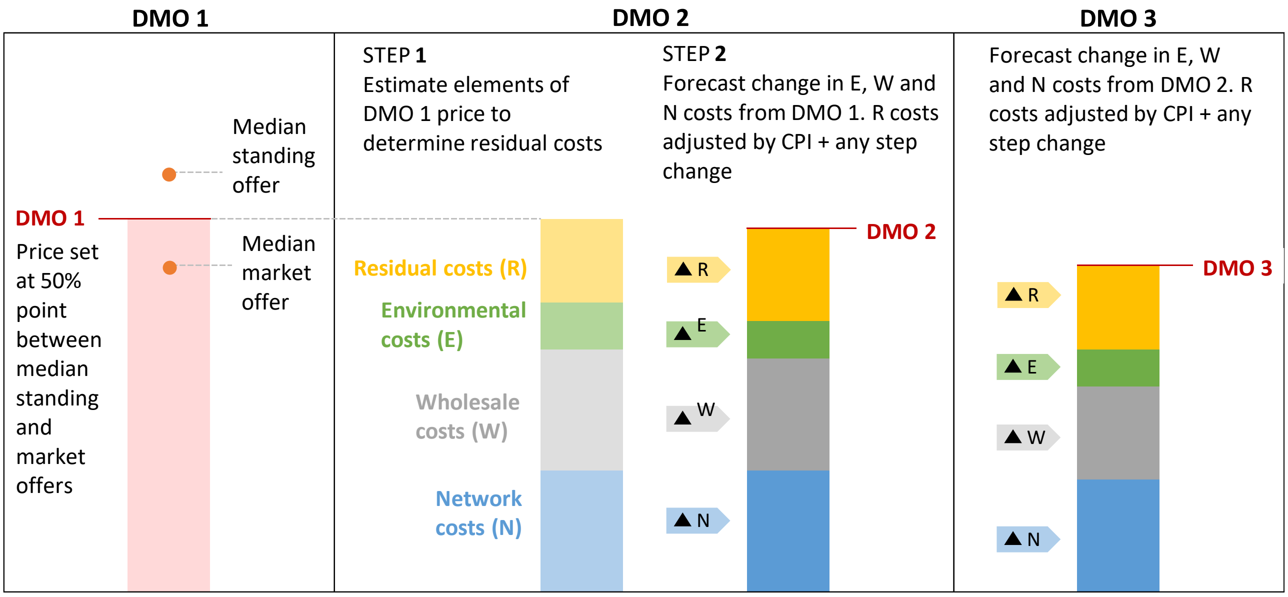
We called the above an 'indexation' approach.

We considered the indexation approach was appropriate to continue in our DMO 3 determination because:

- the DMO 2 price (and residual) successfully achieved the objectives and was a suitable basis to continue indexation
- the indexation approach was 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 provided consistency and certainty for stakeholders, which is appropriate given other current market uncertainties relating to COVID-19.

Figure 3.1 illustrates the methodology adopted for DMO 1 to 3.

Figure 3.1: Illustrative example of DMO ‘indexation’ price setting approach



3.3 Overarching framework – future considerations

In this review we are seeking stakeholders’ views on our overarching approach to the individual DMO components each year.

Under the indexation approach, as shown in Figure 3.1, we have carried forward the price of the previous year, with adjustments to each cost component based on how these were expected to change.

A question for this review is whether we continue to use this approach or build up the total DMO price each year based on the forecast costs of each DMO cost stack component.

We note that under either of the above pricing approaches our method of forecasting input costs would remain broadly the same.

However, our proposed options to deal with retail and residual costs, set out in section 4 below, entail quite different approaches.

- Option 1 would see us treat retail costs and any additional allowance as annual costs
- Options 2 and 3 would see us continue to index the residual component in some form.

Our preliminary view is that for continuity and transparency, it is reasonable to treat all the cost stack components in the same way as the residual/retail component in each option. That is, under option 1, we would build up the DMO price based forecasts for wholesale, network and environment costs as absolute values, while under options 2 and 3 we would continue to index the previous year’s values.

We are interested in stakeholders’ views on the implications of the different overarching approaches.

4 Retail costs, profit margin and DMO allowance

Sections 4.1 to 4.3 set out 3 options for estimating retail costs, profit margin and additional allowance for the next DMO.

4.1 Option 1 – Estimating retail costs and a DMO allowance

One option for retail costs would be to treat these as a direct cost input, assessing them each year, and treating them as a standalone annual cost component.

Key differences from the current DMO approach would be the requirement to:

- estimate typical retail costs, including costs to acquire and retain customers
- determine an allowance above typical costs to cover the retail margin and to meet the DMO objectives.

There are several reasons why it may be appropriate to apply a bottom-up methodology for determining the retail costs and margin available to retailers in the DMO price:

- New information from the ACCC’s Electricity Monitoring Inquiry will be available in time for our DMO 4 determination that will provide us with a robust estimate of retail costs. This data will cover 2020–21.
- Because standing and market offer prices at the time DMO 1 prices were set varied by region and customer type, the residual (including any additional allowance needed to meet the DMO objectives) also differed. Setting a consistent allowance on top of retail costs for each region and customer type to meet the DMO objectives may be a more suitable starting point for an approach we intend to utilise for 3 to 5 years (see section 4.4).
- The residual is based on the distribution of market and standing offer prices in October 2018 in each region for each customer type. By preserving the residual in subsequent DMOs, the DMO price has reflected retailer pricing strategies from 2018, which may not align with current market offer pricing strategies.
- Separately identified amounts for typical retail costs and the margin available to retailers to meet the DMO objectives would provide transparency on the additional cost customers are paying by not engaging in the market.
- A cost-based approach applied to retail costs and additional DMO allowance provides clearly defined rules for assessing each element of the DMO price.

Estimating retail costs

A cost based approach to estimating retail costs requires access to robust data. Possible options to obtain retail cost information are:

- using the ACCC published retail cost information in its Electricity Monitoring Inquiry reports
- obtaining data directly from retailers.

Retail costs will vary across different retailers depending on factors such as retailer size and strategic positioning (for example, some retailers may offer enhanced customer service as a point of difference). An assessment of costs will therefore require us to specify the characteristics of a typical retailer.

Using ACCC inquiry data to determine retail costs

The ACCC, in its ongoing electricity monitoring inquiry,[21] seeks detailed information from retailers' about their costs to serve, acquire and retain customers.

The ACCC has published retail cost data for 2018–19. By the end of 2021 it also intends to publish a further report covering this data for 2019–20 and 2020–21. Thereafter data will be updated annually until the conclusion of the ACCC inquiry in August 2025.

We see a number of advantages in using this information to estimate typical retail costs in the DMO. The data:

- will be updated annually until at least August 2025. This would allow for a consistent basis to estimate retail operating costs in a number of future DMO decisions
- is obtained under the ACCC's compulsory information gathering powers, providing confidence in its integrity and accuracy compared to ad-hoc informal data requests
- is comprehensive, based on the costs for 18 retailers selling to about 97% of residential customers[22]
- would be available for inclusion in our Draft Determination, allowing the AER to consult with stakeholders on retail costs before the final determination
- is publicly available. This increases transparency and avoids additional regulatory burden on retailers.

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[22] ACCC, Inquiry into the National Electricity Market, November 2019 Report, p.112

However, there are some issues we need to consider in using this data. The retail cost data:

- are for actual costs, which cover a period of time prior to the relevant DMO period. The most recent ACCC retail cost data that will be available for DMO 4 (2022–23) will reflect costs in 2020–21. We discuss the implications of this lag in section later in this section.
- is a weighted average of costs, with the retail costs of the largest retailers having the greatest influence on the overall average retail costs. Smaller retailers that have not achieved economies of scale and are unable to spread fixed costs across a large customer base may have higher than average per customer retail costs.
- is provided at a jurisdictional level (NSW, SA and south-east Queensland) rather than distributor level.
    - We consider using single figure for the 3 NSW distributors is reasonable on the basis that retail costs should not vary significantly across distributors within a jurisdiction.
    - Further, retailers are unlikely to be able to provide accurate breakdowns of retail costs at the distributor level beyond arbitrary allocations based on numbers of customers in each region.
- aggregates the costs for different customer types. This means any differences in costs are smeared across the overall group and not fully reflected on a per customer basis. We would not be able to identify specific cost to serve standing offer customers, for instance, or customers on different tariff types.

Requesting separate retailer cost information

Some of the aggregation issues identified above could be addressed if we obtained retailer cost data and undertook our own analysis to estimate typical retail operating costs.

Given retailers already report this information to the ACCC, the key purpose for separately requesting cost information would be that it could potentially enable us to further identify costs by network regions in NSW, and by offer and tariff types that reflect the DMO customer classes.

This is not our preferred option for a number of reasons:

- Any variance in retailer operating costs by tariff type or distribution region is likely to be marginal. The main drivers of retail costs are customer service, IT equipment and labour costs.[23] It is unlikely for retailers to have separate customer service, IT systems and labour in place for each tariff type and region.

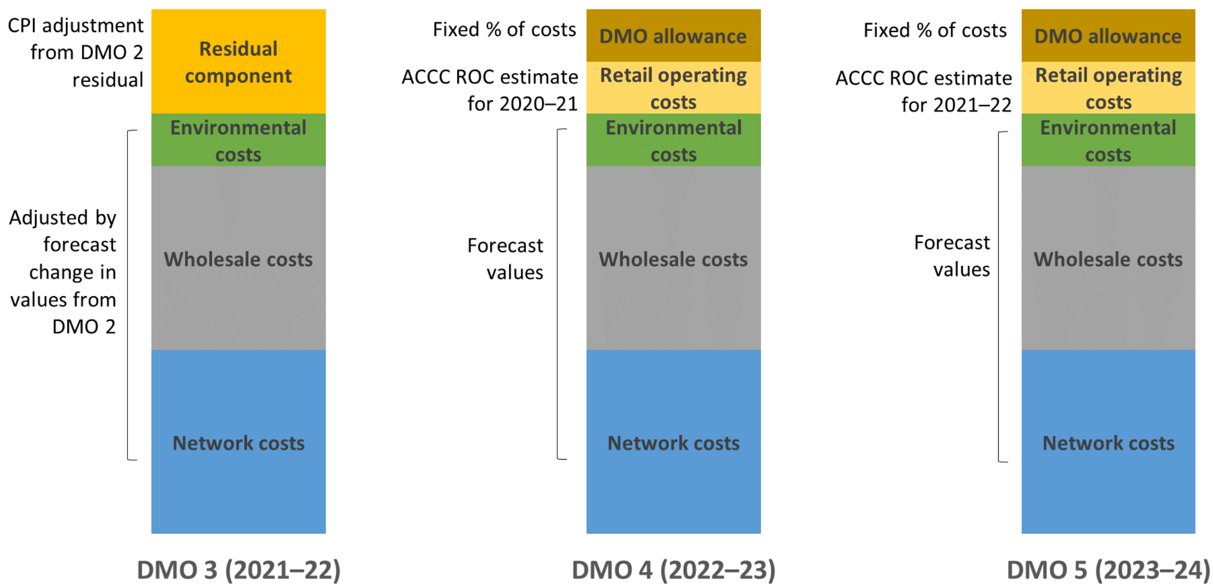
- Any request for additional data would be better focused on costs not captured by the ACCC data (e.g. advanced metering costs).

Our preliminary view is that the ACCC analysis of retail costs for 2020–21 will be a robust and reasonable estimate of typical retail operating costs.

Network, wholesale and environmental costs would also be forecast each year to build the cost stack for each DMO price.

Figure 4.1 illustrates the annual approach under this option.

Figure 4.1 – DMO cost based price setting approach using ACCC retail cost data



Question 1: What is the most appropriate approach to estimating retail operating costs under a cost based approach?

Question 2: What information should we have regard to in estimating retail costs?

[23] Figure 2.42 and 2.47, ACCC, Inquiry into the National Electricity Market – November 2019 Report, pp.74,79.

Step change framework

The forward-looking step change framework was important under our indexation approach because there was no true-up mechanism that would enable retailers to retrospectively ‘catch up’ any cost increases in a future determination.

The framework addressed the risk that significant increases in retailers’ costs might impact some retailers’ abilities to make a profit or recover their costs to serve customers.

Under option 1, if we estimated retail costs each year based on the most recent ACCC published retail costs, any cost variances as a result of exogenous impacts would be caught up by retailers within the following 2 years.

We consider a 2 year delay in reflecting variances should not jeopardise retailer viability nor the DMO policy objectives, because:

- most exogenous changes will be small in nature
- our intention is that the DMO price should remain well above the level where retailers can recover costs. This means there would be sufficient allowance for retailers to carry cost increases without it impacting their ability to recover efficient costs and make a profit.

Our preliminary view is that using annual cost information as proposed under option 1 renders the step change framework redundant. It should be removed from the DMO methodology if this option is adopted.

Removing the step change framework from the DMO methodology would also address stakeholder concerns about our approach to annual retail cost changes, raised in previous determinations. In particular:

- it removes the need for us to exercise judgement about the reasonableness of retailer information, and what cost changes are ‘material’
- it doesn’t rely on information provided by retailers, so addresses an information asymmetry issue highlighted by consumer stakeholders
- it addresses the risk of incremental cost changes impacting the policy objectives over time.

Question 3: What are the impacts on retailers facing a time lag for recovery of retail costs?

Setting the DMO allowance

Regulators have typically acknowledged the principle that retailers need to make some profit from regulated customers and have set a retail margin component above the level of efficient costs.

Depending on the intention of the regulation, regulators may also apply an allowance above a reasonable retail margin, to facilitate some customer price dispersion providing customers an incentive to switch.

If we adopted a cost based approach to determining a retailers' typical costs, we would need to consider retailer profit margin, as well as an additional allowance that we determined met the DMO objectives.

We see 2 options for how we address retail margin and allowance within the DMO cost stack:

- Set a DMO allowance' above our estimate of typical retail costs that includes a reasonable retail margin, as well as an additional allowance to achieve the DMO objectives.
- Determine a reasonable retail margin, plus a separate DMO allowance to facilitate competition

Both approaches would provide transparency about the margin available to retailers in the DMO offer, and the price premium standing offer customers would pay by not switching to a market offer.

However, a single DMO allowance would avoid allocating costs between retail margin and any additional allowance. This level of specificity may not be necessary given the DMO's status as a price well above efficient costs.

Alternatively, as discussed below, other sources of information may provide guidance we could draw on in setting a separate retail margin, such as historical margins and other Australian regulators allowable retail margins.

Considerations in setting the DMO allowance

We expect stakeholders will have a range of different views on what DMO allowance best meets the objectives.

In determining a particular allowance we would have regard to a range of factors, including:

- the nominal retail margins achieved under our previous determinations
- other regulators' consideration of reasonable margin and any additional allowance
- the ACCC monitoring report data.

We are interested in stakeholder views on what other factors should guide our consideration of an allowance that meets the objectives. Discussed below are the key DMO objectives that must be considered in setting the level of any DMO allowance.

Reasonable profit

Section 16(4) of the regulations requires that we have regard to the principle that retailers are entitled to make a reasonable profit from customers.

As a starting point for consideration of a DMO allowance, we would have regard to the decisions of a number of economic regulators that currently perform similar assessments, as well as what margins retailers have made in the competitive DMO markets.

Table 4.1 sets out the most recent decisions from these regulators. We note these margins are intended to compensate retailers for the risks involved in retailing and may not be a good guide to the margin required to meet the DMO objectives.

Table 4.1: Summary of regulator approach to setting retailer margins

Regulator	Margin[24]	Description of margin and policy goals
Essential Services Commission, VIC (ESC)	5.7%	Reflects the efficient costs, including retail margin, of running a retailer business.[25]
Independent Competition and Regulatory Commission, ACT (ICRC)	5.3%	The retail margin is a profit margin that provides a return on the investment made by an efficient retailer in providing retail electricity services.[26]
Office of the Tasmanian Economic Regulator (OTTER)	5.4%	Regulated prices, including margins, are set by OTTER at a level that does not restrict competition, but reflects efficient costs as far as possible.[27]

24 Retailer margins in this table have been expressed as the percentage of the total regulated price, including GST.

25 ESC, *Victorian Default Offer to apply from 1 July 2019: Advice to Victorian Government*, 3 May 2019, p. 20.

26 ICRC, *Electricity Price Investigation 2020–24 Final Report*, June 2020, p. 48.

27 OTTER, *Standing Offer 2016 Determination Investigation*, May 2016, p. VI.

The DMO has a different policy objective to provide a ‘fall back option’ that is not unjustifiably high, rather than to be set the price at the level of efficient costs plus margin. The DMO also operates in different market contexts:

- in competitive markets with a large number of retailers
- with large ranges in market offer prices, including low priced market offers available to customers
- with low proportions of customers on standing offers paying the regulated price.

Table 4.2 summarises ACCC analysis of retailer margins from 2017–18 and 2018–19. This analysis suggests that retailers typically achieve greater margins for small business customers (around 8%), and demonstrates that margins differ by region, with retailers achieving the greatest margins for residential customers in NSW.

Table 4.2: Summary of retailer margins as a % of total retail cost

Customer type	Region	Retailer Margins 2018–19	Retailer margins 2017–18
Residential	NSW	5.1%	9.9%
Residential	South-east Queensland	1.2%	2.7%
Residential	SA	1.1%	4.1%
Small Business	NEM	8.2%	8.3%

Source: ACCC November 2019 Report; ACCC Retail Electricity Pricing Inquiry. Retailer margins include both standing and market offer customer bases.

Protection against unjustifiably high prices

Before the first DMO came into effect on 1 July 2019, a number of standing offer prices were significantly higher than market offer prices. These prices had no basis in actual costs to serve standing offer customers, but provide some guidance about what the ACCC considered to be ‘unjustifiably high’ prices.

AER analysis of standing and market offers available in June 2019, prior to the introduction of the DMO, found:

- the median standing offer for residential and small business customers was at least 20% higher than the median market offer
- the maximum standing offer for residential and small business customers was at least 49% higher than the median market offer.

After the DMO came into effect, retailers were required to reduce the prices of their standing offers to the DMO cap. AER analysis of standing and market offer prices post-July 2019 observed the median standing offer price converge on the DMO as expected. In August 2021 the DMO price:

- for residential customers, was between 6% (SAPN) and 19% (Ausgrid) higher than the median market offer
- for small businesses, was between 14% (Energex) and 28% (Ausgrid) higher than the median offer.

Question 4: Is the DMO protecting customers from unjustifiably high prices? If so, why?

Question 5: What factors are relevant in considering whether a price is excessive?

Incentives for competition, investment and customer engagement

Retailers have traditionally relied on discounts as the main way to motivate customers to switch. Since the introduction of the Code, they have moved from offering conditional discounts to promoting discounts off the DMO reference price.

In submissions to previous DMO consultations, retailers have stated that if the DMO price is set too low, the percentage off the reference price risks being too small to motivate customers to switch, dampening competition.

Additionally, if the DMO is set too low, retailers that invest in technologies and personnel to compete on non-price aspects of offers, such as customer service, bundling electricity with a mobile phone or internet service, or offering online portals and apps to monitor usage, may struggle to provide these products.

To facilitate customer engagement, the DMO price should also be far enough above the level of most market offers that there is clear incentive to switch from a standing offer.

In considering an allowance that provides incentives for competition, innovation, investment and customer engagement, we would have regard to a range of information, such as:

- savings available for customers as a result of switching from the DMO to the median market offer. We consider these potential savings maintain the incentive for customers on the DMO to search for better deals.[28]
- information from other agencies that provides insights into switching behaviour. We note for example, the ACCC has not found evidence the DMO has had adverse impacts on market offer prices, and that a larger proportion of customers chose market offers over standing offers which indicated greater customer engagement.[29]

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[28] AER, *Default Market Offer Prices 2019–20*, *Final Determination*, April 2020, p.39-40.

[29] ACCC, *Inquiry into the National Electricity Market*, September 2020 report, p.4.

Table 4.3 Savings available from switching

	Savings available from switching from the DMO to median market offer depending on region		
Customer type	**DMO 1**	**DMO 2**	**DMO 3**
Residential	8–9 %	10–17%	10–16%
Small business	8–10%	12–20%	12–22%

Question 6: What other factors should we consider when assessing the DMO allowance required to incentivise customers to engage in the market?

A consistent allowance across all DMO customer types and regions

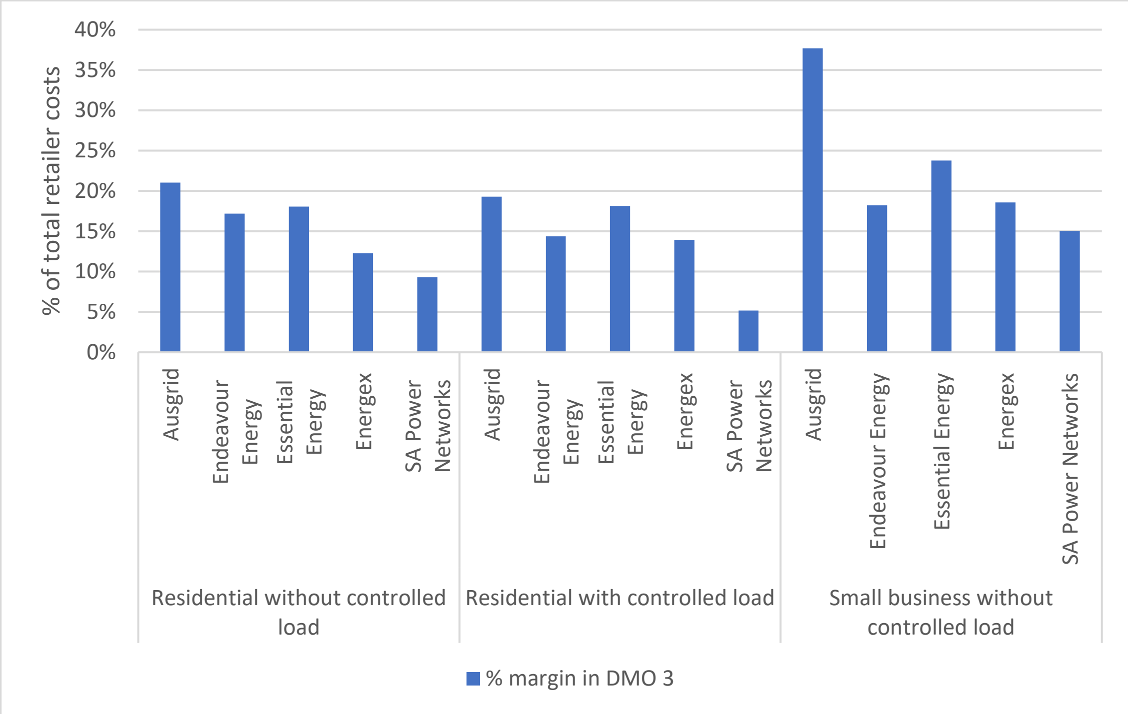
As discussed above, we have observed the difference between the DMO and the median market offer varies by region and customer type. This suggests that the margins available to retailers selling electricity at the DMO price also vary, although it depends on each retailer's underlying costs.

Figure 4.2 sets out a simple analysis of possible margins and additional allowance in the DMO 3 price by subtracting the ACCC's observed 2018–19 average retail costs,[30] and DMO 3 wholesale, network and environment costs. These are approximate calculations, as retail costs may have changed over time, and margins will differ depending on each retailer's situation.

It indicates the current effective (weighted average) margin across the DMO regions and customer types is around 15–20%.

[30] These are the most recent available costs. The ACCC aims to update these costs with 2019–20 and 2020–21 costs in its November 2021 report.

Figure 4.2: Nominal retail margin plus additional allowance available in DMO 3



Source: ACCC November 2019 Report, ACCC Retail Electricity Pricing Inquiry; AER analysis.

As the DMO objectives are the same regardless of region and customer type, it is reasonable to argue a DMO allowance that meets the DMO objectives should also be consistent across DMO regions.

Figure 4.2 illustrates that one implication of applying a single margin across the board is that the nominal margins may increase for some regions and customer types and decrease in others.

For instance, depending on the DMO allowance, the margins available to retailers in Energex and SAPN regions may increase above previous years' allowances. It may decrease in the NSW regions, where the margins have been comparatively higher.

In considering setting a consistent margin, we would consider factors, including:

- the number of standing offer customers affected by a DMO price with a higher margin, and the size of the increase
- stakeholder feedback on the impact of the adjusted margin.

If our setting a consistent margin resulted in a higher DMO price, we could not prevent retailers increasing their standing offer prices. However, as the DMO is a maximum price there is no requirement for retailers to do this. Given the increase would only reflect an allowance to facilitate retail competition, not higher costs to serve standing offer customers, increasing costs for this reason may be difficult to justify to customers.

Question 7: Should the margin above efficient costs in the DMO price be consistent across all DMO regions and customer types?

Question 8: What is an appropriate DMO margin to achieve the policy goals?

4.2 Option 2 – continue indexation of the DMO residual

In our DMO 3 Final Determination, we demonstrated that the DMO 3 price (and therefore the DMO residual) would meet the objectives. Our analysis, which used offers from March 2021, noted:

- The gap between the DMO 3 price and the median market offer (our indicator of the reasonable costs to supply customers in a region) would be large enough that retailers could make a reasonable profit.
- There would be incentives for retailers to compete, innovate and invest. For instance:
  - retailers were competing for market share, with most offering significant discounts from the DMO reference price
  - retailers were increasingly competing on non-price elements, including bundled services
  - retailers were continuing to enter the market.
- The substantial difference between the DMO price and the lowest offer in each region would provide incentives for DMO customers to shop around.

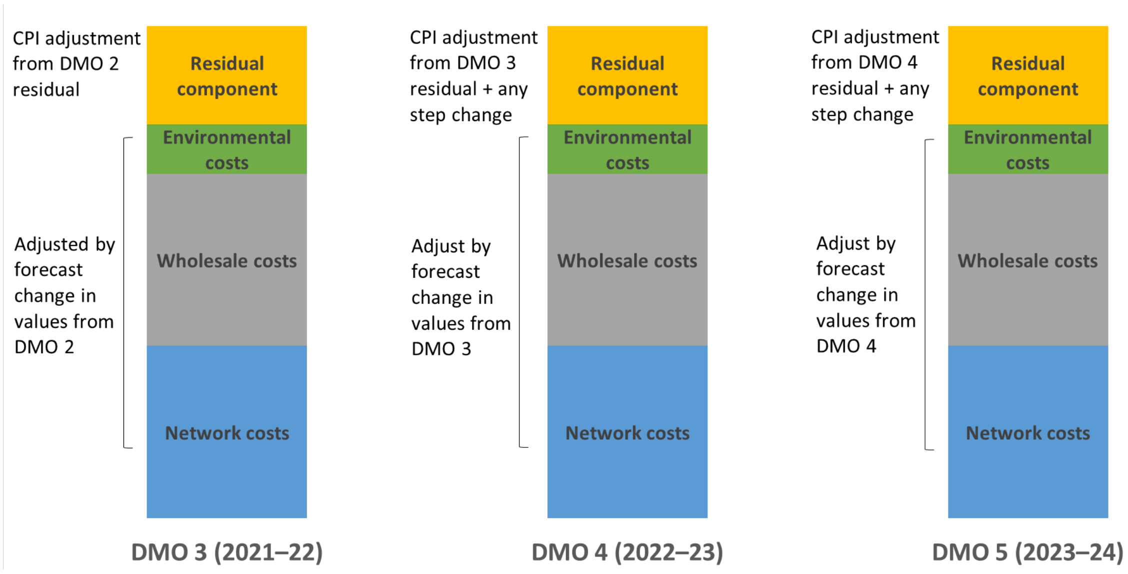
These outcomes provide a reasonable basis to continue the indexation approach we have used in previous years. That is:

- estimate changes in retailers' input costs – network, wholesale and environmental costs - for the coming year
- apply forecast CPI to the DMO 3 residual component
- consider any exogenous cost changes under the step change framework (potentially with some modification)

We are separately considering providing an allowance within the residual to reflect smart meter costs (as discussed in chapter 8).

Figure 4.3 illustrates this option.

Figure 4.3: Continue indexation of the residual



There are a number of reasons why continuing the existing indexation approach would be appropriate.

- In addition to our analysis above, recent ACCC analysis supports the conclusion that the DMO price (based on our indexation methodology) is meeting the objectives, benefitting consumers and not causing negative market impacts.[31]
- It builds on earlier versions of the DMO. Many stakeholders have supported this approach as providing predictability and continuity. Continuing the indexation of the residual component would also be the most straightforward approach for updating the DMO price of the options outlined in this review.
- It accepts the status quo for retail costs plus residual margin, avoiding potentially contentious discussions about what retail costs should be included, and what additional allowance is appropriate to meet the DMO objectives. The DMO price would continue at an unspecified level above efficient costs.
- It would avoid more pronounced price changes for standing offer customers in some areas, as may occur under option 1 (cost based approach).
- If we made an allowance for advanced meter costs, this may address some stakeholders' concerns that the residual component does not reflect these.

[31] ACCC, *Inquiry into the National Electricity Market - May 2021 Report,* Commonwealth of Australia, May 2021, p.5, 46.

However, there are a number of issues we would need to consider in deciding whether to use this approach.

- As illustrated in figure 4.2, the size of the residual component varies across the regions and customer classes covered by the DMO. The DMO 1 price was set using market offers from October 2018 and the variance in residual reflects the market conditions at that time. These market conditions may no longer be relevant. Additionally, a consistent margin across regions and customers may provide more consistent incentives for customers to engage in the market and pricing protections for customers that stay on standing offers and encourage further retailer entry in regions with lower margins at present.
- This approach precludes the benefit of any achieved improvements in productivity from being reflected in the DMO price and passed onto DMO customers. Under the current indexation approach, this would require assessment of a step change decrease in costs. Retailers in previous DMO decisions have not provided information detailing reductions in costs and have little incentive to do so.

We note in chapter 9 that we are intending to update the annual consumption amounts for each customer type. For consistency, it would be necessary to re-calculate the DMO 1 price and cost stack components, including the residual component, to reflect the new usage amounts. The remaining residual component would then need to be adjusted by CPI (either by reapplying the CPI forecast at the time or using actual CPI).

Amending the step change framework

Option 2 would require us to retain the step change framework for considering cost changes. While this would enable us to make allowance for material changes in retailers' operating costs, over time smaller cost changes may cause the residual (and therefore the nominal allowance available retailers) to diverge from its DMO 1 level.

Noting the previously mentioned issues with the step change framework, we are seeking stakeholders' views about possible amendments to the framework that would address these issues.

- **Quantifying 'materiality'** – In our DMO 3 Final Determination, we clarified our position that a material cost change is one that risks achievement of the DMO objectives if no allowance for the cost change is provided. That is:
    - it impacts retailers' abilities to recover costs and make a reasonable profit
    - it has a negative impact on competition
    - it resulted in standing offer customers paying an excessive price.

  While not a percentage figure, our preliminary view is that these criteria provide clear guidance about the significant nature of any cost change we would consider material.
- **Information quality –** It is difficult to verify predicted costs changes without going into granular detail of commercially sensitive information and forecast assumptions. Independently assured information may address our concerns but would involve cost and administrative burden.

- **Standardising information –** It has been challenging to compare costs between retailers for the same step change item. Standardised templates or definitions may provide a means to address these problems.

Question 9: Should we continue indexing the current residual?

Question 10: What are the benefits and disadvantages of this approach?

Question 11: How could the step change framework be improved?

4.3 Option 3 – adjust the residual to reflect changes in retail costs using ACCC data

As noted in the discussion of option 2, a key consideration in moving away from the current residual calculation approach is the possibility that retail operating costs may significantly diverge over time from the level provided for in the residual in DMO 1.

The availability of the ACCC's retail cost data provides us with an option to address this element of the indexation methodology. The ACCC's next electricity market monitoring report will set out retailers' operating costs for 2020–21. Given DMO 1 prices were based on October 2018 offers, comparing this figure to the equivalent figure in 2018-19 would provide an authoritative estimate of how retail costs have changed over the period.

Adjusting the DMO residual up or down by this figure would ensure that the DMO 4 residual remains closely aligned with the DMO 1 level.

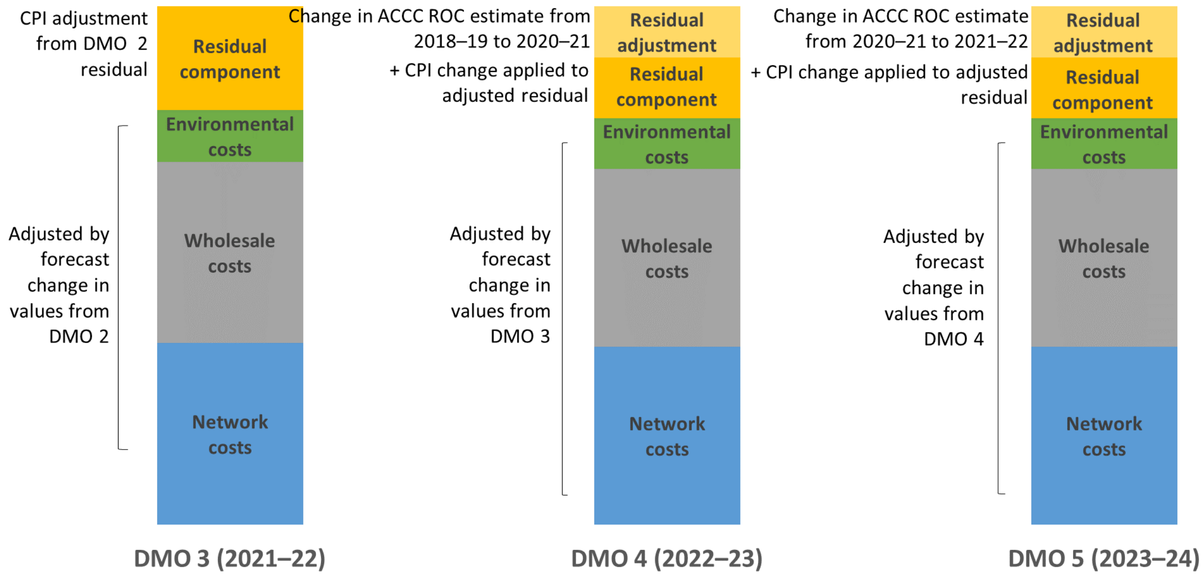
For example, the DMO 3 residual component for residential customers in the Ausgrid region is $377. If the ACCC data indicated retail costs had increased by $15 per customer in real terms since 2018-19, we would make an adjustment to add $15 to the DMO 4 residual.

Forecast CPI would then be applied to ensure this adjustment holds its value in real terms for the coming year.

Other input costs would also continue to be calculated as they were in DMO 3 under this option.

Figure 4.4 illustrates this option. We call this the annual residual adjustment approach.

Figure 4.4: Annual residual adjustment approach



The reasons for continuing the indexation approach, set out previously under the discussion of option 2, also apply to this approach.

However, we see additional benefits in this approach.

This approach may provide customers on standing offers with savings if retailers' productivity gains outweigh increases in their costs to serve. Downwards adjustments to the residual component are otherwise unlikely under the indexation approach, as negative year-on-year changes in CPI are uncommon.

A key potential advantage of this approach over option 2 is that the ACCC data provides a basis for a transparent annual adjustment to the residual. This approach would also ensure that the additional allowance incorporated in the residual component remains closely aligned with the DMO 1 from year to year.

As with option 1, our preliminary view is that making annual adjustments in this way would render the step change framework redundant, as any changes in retailer costs would be reflected in the ACCC data, and ultimately in the DMO price.

However, this approach would not address the variance in the residual between regions and customer types.

Question 12: Should we perform an adjustment to reflect movement in retail costs and, if so, should this be performed on an annual basis?

4.4 Duration of the methodology

This review provides an opportunity for us engage with stakeholders to determine an approach to most aspects of setting the DMO price. To provide regulatory certainty and consistency, the revised approach should remain in place without substantial amendment for a period of time.

We would consider the following elements of our approach fixed for the duration:

- The overarching approach to setting retail costs
- The level of the DMO allowance (under the option 1 approach)
- The annual adjustment approach
- The settings for our wholesale forecasts and the other energy costs we include in our calculations
- The annual usage amounts.

We are interested in stakeholders' views on an appropriate duration for the methodology to remain in place.

5 year duration

A 5 year duration before any further detailed review of the methodology and assumptions would provide stakeholders with a long period of stability and consistency.

If we were to adopt this approach, the ACCC's retail cost data would not be available for years 4 and 5, as the final report is due to be published in November 2024, prior to the expected conclusion of the inquiry in August 2025.

If we were to adopt an approach that includes annual adjustments of retail costs, we would need to develop our own retail cost benchmarks or consider other information sources for these years. We would need to address the risk of a change in methodology between years 3 and 4 but consider this risk would potentially be low if we replicated the ACCC analysis.

A further issue with a longer DMO period is that annual usage may shift significantly between years 1 and 5.

3 year duration

A 3 year DMO period would align with the availability of ACCC retail reports and would avoid us needing to separately estimate retail costs.

However, it would mean a relatively short window between this review and the next.

A third option may be to conduct a minimal review, potentially limited to updating annual usage benchmarks, and whether the DMO allowance is meeting the objectives, at the 3 year mark, with a more comprehensive methodology review after 5 years.

Question 13: How long should we retain the methodology we adopt in this review?

5 Wholesale costs

With the review of the DMO methodology, it is appropriate to re-evaluate the approach and settings used to forecast wholesale costs.

Our view remains that the overarching ‘market based’ approach to forecasting we have adopted in previous DMO determinations remains the most transparent and appropriate for future determinations. We do not propose a fundamental change in this aspect of our approach.

However, the review is an opportunity to seek stakeholder views on whether some key variables that have a significant influence on our forecasts continue to meet the DMO objectives and stakeholder expectations.

These variables include the assumed hedging strategy of our ‘representative retailer’ and the error margin in our forecasts.

It is also appropriate to reconsider whether our approach to other cost elements – such as other energy costs – remains appropriate.

As with other elements of the DMO methodology, our intention is to retain the wholesale settings we determine in this review until the next DMO review.

5.1 Wholesale cost forecast – market based approach

Given our intention to retain a market based approach to forecast wholesale costs, it is relevant to summarise the principles of this approach. Further details about the specific approach adopted for our DMO 2 and DMO 3 determinations can be found in detailed consultant reports.[32]

Our forecasts of wholesale prices incurred by retailers have to date taken into account futures market contract trade volumes and prices.

The methodology was designed to simulate the wholesale energy market from a retailer’s perspective, and reflect all costs associated with a retailer’s purchase of energy from the National Electricity Market (NEM).

The costs are a combination of hedging and spot market costs (wholesale energy costs), as well as other fees related to participation in the NEM (other energy costs).

Under the market based forecast approach, the wholesale price is a function of projected energy supply and demand forecasts, the assumed strategy to manage exposure to the spot market (hedging strategy) and any residual exposure to forecast spot market prices.

32 https://www.aer.gov.au/retail-markets/guidelines-reviews/retail-electricity-prices-review-determination-of-default-market-offer-prices-2021-22/final-decision

Estimating demand and supply – spot price simulation

The demand forecasts used in our approach are a function of AEMO's Electricity Statement of Opportunities (ESOO) central scenario, as well as estimated uptake of rooftop solar photovoltaic (PV), and weather simulations in respect to their impact on demand and availability of renewable resources. The supply forecast is broadly aligned with AEMO's Integrated System Plan, which takes into consideration announced new investments, retirements, fuel costs and simulated thermal power generation availability.

The demand and supply forecasts are used to produce a distribution of simulated hourly spot market price outcomes for the year using a dynamic bidding process, representative of volatility in the spot market. A retailer mitigates spot market risks by entering into electricity futures contracts traded on the Australian Securities Exchange (ASX) or negotiated directly between the parties over-the-counter (OTC), to lock in future electricity prices.

Hedging strategy

The hedging strategy applied in the methodology assumes that a retailer will seek to minimise variability in the wholesale cost (and not just minimise the cost), by building a hedge book consisting of a portfolio of base, peak and cap quarterly contracts from the date of the retailer's first trade.

Hedge book cost and build period

Hedged wholesale costs are equal to the sum of the spot purchase cost, contract purchase costs as per the defined contracting strategy, and difference payments.

ASX contract price and trade volume data is used to estimate contract purchase costs. Per the hedging strategy, the hedge book consists of a portfolio of base, peak and cap quarterly contracts – hence prices for these products need to be derived. Trade volume weighted prices (TWP) for the relevant period for the included contract types are used to estimate their costs.

In previous determinations we assumed that a retailer would start building its hedge book from the date of first contract trade (which is up to 36 months before the start of the relevant quarter). We discuss the implications of different hedging options below.

Estimating the wholesale cost

Spot market prices depend on supply–demand factors such as the availability of generation capacity or changes in customer load. Short term changes in supply and demand conditions, such as unplanned plant outages or weather events, can cause market volatility, including spot price volatility.

Under the market based approach to forecasting, consultants typically attempt to address this uncertainty by modelling hundreds of combinations of the relevant variables (including weather, renewable generation and thermal generation outages), resulting in a range of simulated spot prices.

Broadly speaking, the range represents a distribution of probabilities of different price outcomes.

Prices at the upper end of the range represent prices that would occur under a less likely combination of factors, and therefore are less likely to be exceeded during the forecast period. Prices in the middle of the range represent more likely outcomes but have a greater risk that real world prices will be higher.

In our previous determinations, we adopted the 95th percentile hedged wholesale cost estimate to minimise the chance of understating the risk associated with procuring wholesale electricity to serve retail load.

Distribution Loss Factors (DLF) for each network area and average Marginal Loss Factors (MLF) for transmission as published by AEMO, are applied to the WEC estimates to account for losses in transporting electricity to consumers.

Other energy costs

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

NEM management fees are estimated using the latest available AEMO Budget and Fees document. RERT and ancillary services requirements are inherently uncertain and volatile. The preceding 12 months of actual charges as published by AEMO are used as an estimate of requirements in the following 12 months.

Summary

We consider the approach of taking into account futures market data remains appropriate as the futures contract market is a reflection of expectations of spot market outcomes. At any point in time the traded contract price reflects the expected supply and demand conditions that vary over time as market expectations change.

The framework for price forecasting relies on transparent, publicly available market information, and has generally been supported by stakeholders.

Question 14: Is our existing wholesale cost forecasting methodology, in terms of its approach and considerations (modelling of demand and supply, spot price, hedging etc.) complete, appropriate and representative of costs to supply energy?

5.2 Hedging strategy and forecast error margin

The key methodological variables that we are seeking stakeholders' views on are:

- the assumed hedging strategy of our representative retailer, including hedge book build period
- the nominal margin for error in our forecasts.

Hedging strategy and spot market exposure

Our previous wholesale cost forecasting methodology applied a hedging strategy that minimised volatility in the wholesale price. It assumed a retailer would start building their hedge book from the date of the first contract trade, as opposed to setting arbitrary cut-off dates and book build periods.

We considered this a 'risk averse' approach because the hedging strategy adopted results in a very small proportion (less than 1%) of the total load being exposed to the spot market.

We note we do not have visibility of retailers' hedging strategies, or their levels of spot market exposure. However, we expect individual retailers will adopt different strategies to manage their spot market risk for a range of reasons. However, we considered a risk averse retailer was appropriate because it:

- acknowledged different retailers have different retail loads with different wholesale costs
- maximised the opportunity for retailers to compete below the wholesale component of the DMO price cap
- provided a reasonable estimate of the true wholesale cost for different retailers.

Stakeholders have generally been supportive of this approach, noting the importance of consistency.

In the context of our forecasting methodology, different hedging strategies have different implications for the relative volatility (or stability) of the DMO forecasts between years.

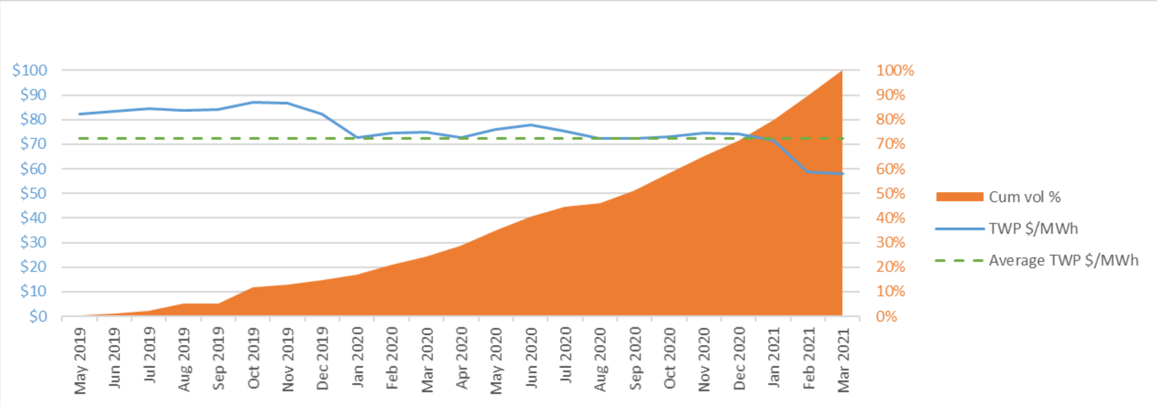
Hedging period

A longer hedge book build period to some degree smooths out price fluctuations, resulting in less pronounced changes in forecast prices from year to year. Conversely, a shorter hedge book build period results in prevailing wholesale prices being more reflected in the DMO forecasts, resulting in greater volatility in our forecasts from year to year.

Figures 5.1 and 5.2 provide a simplified example of the impact of the assumed hedging period, based on a single quarter futures contract price.

Figure 5.1 depicts a NSW base futures contract price and trade volume for Q1 2022 from date of first trade to 1 April 2021, with an average trade weighted price (TWP) of $72.52/MWh. As shown, the TWP started to decline from January 2021, falling to $57.99/MWh in March 2021. Because we calculate the average TWP from the date of first trade (May 2019), the decline in prices since January 2021 has had a relatively low impact on the average TWP across the entire period.

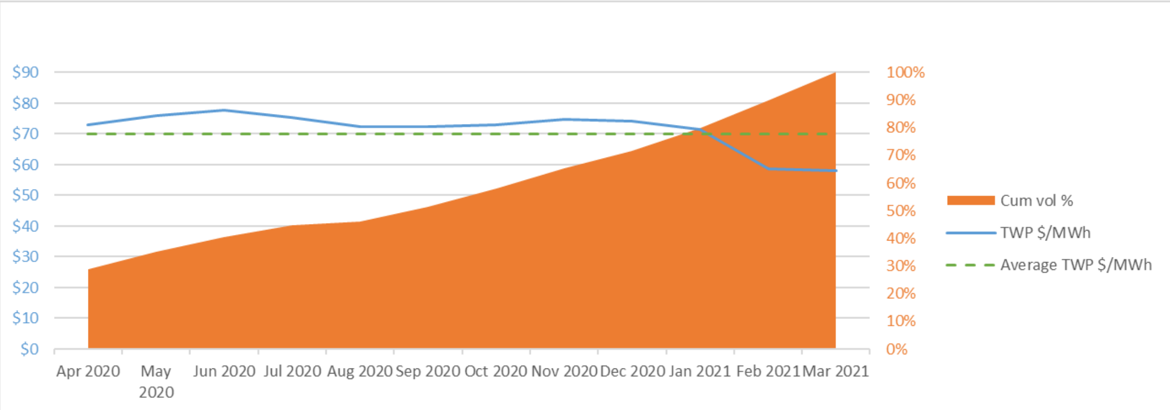
Figure 5.1: NSW Q1 2022 base futures TWP including all trades



In contrast, figure 5.2 shows the same quarter of base futures contracts under a 12 month hedge book build period. Over the period, the lower prices from January have a proportionally greater influence, and result in an average TWP of $69.85/MWh. Additionally, the shorter period does not include the higher contract prices observed between May 2019 and March 2020 when calculating the average TWP.

The $2.67/MWh difference the between these hedging approaches would equate to around $10 difference to the annual DMO price.

Figure 5.2: NSW Q1 2022 base futures TWP last 12 months from cut-off



While the adoption of a shorter hedge period resulted in a lower price under the above scenarios in a market with falling contract prices, the opposite result would be seen in a market environment with increasing contract prices.

Figures 5.3 and 5.4 illustrate the impact of different hedge periods where market prices are increasing. The figures depict NSW Q1 2020 TWP prices and volume over a 26 month and 12 month hedging periods respectively.

Figure 5.3: NSW Q1 2020 base futures TWP including all trades

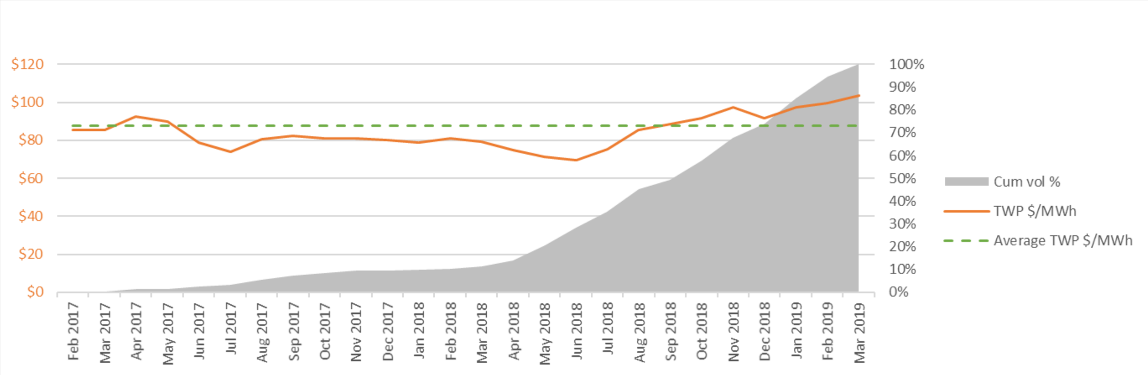
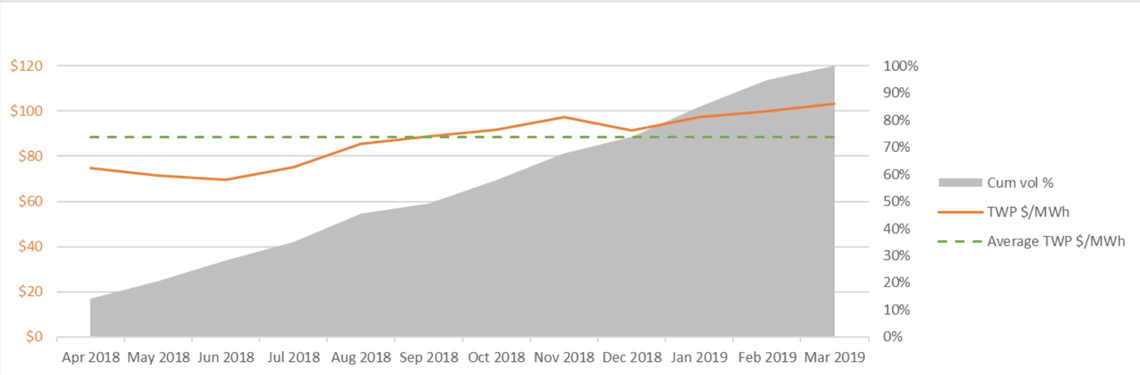


Figure 5.4: NSW Q1 2020 base futures TWP last 12 months from cut-off



The average TWP over a 26 month hedge period is $87.73/MWh, while over a 12 month hedge period, the average TWP is $88.54/MWh.

An assumed mix of contracts that result in higher levels of spot market exposure will also increase volatility because the wholesale cost will be comparatively less influenced by more stable contract prices.

We are seeking stakeholder views on which hedging approach is likely to best achieve the DMO objectives and meet stakeholder expectations.

Option 1 – Retain ‘risk averse’ settings

One option is to continue with the broad settings we have used in previous DMO determinations, with a ‘risk averse’ retailer who seeks to avoid exposure to the spot market.

This would be reflected by use of a 24–36 month hedge book build and an assumed contract mix that seeks to minimise exposure to the spot market.

The main advantages of this approach include relative stability in DMO forecasts from year to year. Price fluctuations have less influence on DMO prices when accounting for more trades over a longer period, compared to a shorter book build.

As the DMO is a regulated price cap, increased stability year-on-year provides certainty to customers and retailers.

While the approach cushions the impact of price rises when wholesale costs are increasing, it may not reflect stakeholder expectations of price reductions at times of low market prices.

We note that given our lack of visibility of retailer spot market exposure, it is possible this approach may not reflect individual retailer practice, even if it does result in more stable annual price outcomes.

Option 2 – Adopt less 'risk averse' settings

Option 2 would be to adopt a less 'risk averse' hedging strategy for our DMO forecasts.

This would be reflected in our methodology by:

- a shorter hedge book build – between 12 and 18 months
- a contract mix that results in an increased level of exposure to the spot market.

Adopting this approach would ensure DMO forecasts were more reflective of current wholesale price expectations by ignoring contract trades further in the past.

It may also more accurately reflect expectations of the spot market and price competition in a market containing retailers with differing contracting strategies competing for market share – such as exist in the DMO regions.

We note that the Essential Services Commission cites this as its reason for adopting a 12 month hedge book build in setting the Victorian Default Offer (VDO).[33]

As shown in figures 5.1 to 5.4, a shorter book build period will increase the magnitude of increases or decreases in forecasts between years, compared to a longer period.

Question 15: Should our existing assumed hedging strategy be adjusted to allow for a higher level of spot market exposure? And if so, what is the appropriate level of exposure? (please also consider this question in conjunction with *Margin for forecast error* discussion below)

[33] ESCV, Victorian Default Offer 2021 Final Decision, 25 November 2020. See: https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer/victorian-default-offer-price-review-2021

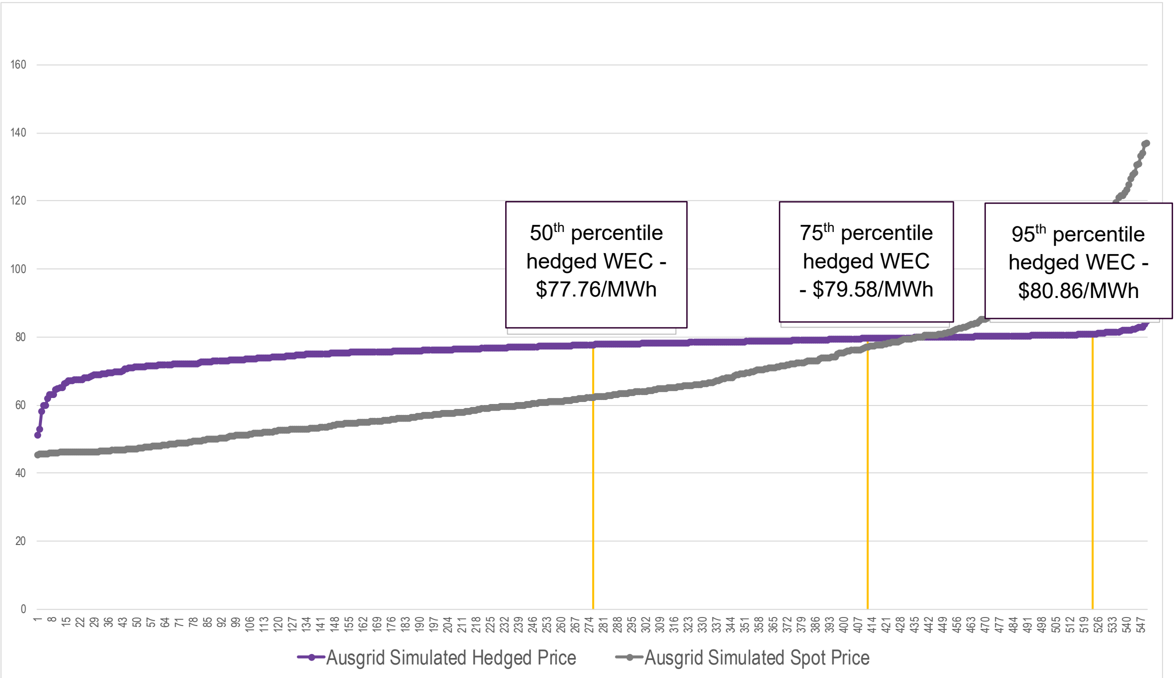
Question 16: Does our assumption of a retailer building their hedge book from the time of the first trade recorded by ASX Energy, remain appropriate, or is a shorter period justified? What is an appropriate period and why?

Margin for forecast error

Our estimate of wholesale costs reflects a point in the range of modelled price outcomes.

Figure 5.5 depicts the range of simulated spot price outcomes, and the hedged wholesale energy prices by applying the adopted hedging strategy for the Ausgrid distribution region for DMO 3.

Figure 5.5: DMO 3 simulated spot price and hedged wholesale cost outcomes – Ausgrid



As can be observed above, under the ‘risk averse’ hedging strategy of our previous determinations, there is a relatively small difference in the wholesale energy cost across the range of modelled outcomes (the 95th percentile hedged price outcome is $3.10/MWh higher than the 50th percentile outcome).

This is due to the hedging strategy resulting in a small proportion of the total forecast load being exposed to the spot market.

If we adopted hedging assumptions that resulted in the greater spot market exposure (as discussed above), we would expect see greater variability in the hedged wholesale cost outcomes at different percentiles.

Option 1 – Continue to use upper range of modelled prices

Our previous approach used prices at the upper end of the modelled range to estimate wholesale costs.[34]

In terms of our DMO forecasts, prices at the upper end of the range are unlikely to be exceeded by actual prices, meaning there is minimal risk that the forecast would be an underestimate of the actual price a retailer faces to purchase energy.

In our previous determinations we considered this was a reasonable setting for the DMO because it:

- acknowledges that different retailers have different retail loads with different true wholesale costs
- provide a reasonable estimate of the true wholesale costs across a variety of different retailers
- was consistent with the DMO objectives by providing an additional safeguard against underestimating retailers' costs.

The rationale for retaining this in DMO 4 would be:

- it is reasonable to retain a low risk of underestimating the wholesale price
- stakeholders in DMO 3 supported this approach (at least in the context of the previous indexation methodology)
- it provides consistency for stakeholders.

Option 2 – Adopt lower point in the range of modelled prices

A price closer to the middle of the range of modelled outcomes would increase the likelihood our forecast would be lower than what a retailer actually incurs.

The rationale for adopting a price closer to the middle of the range – for example, the 75th percentile – could include:

- given the DMO should continue to enable retailers to make a reasonable profit while capping excessively high prices, there would still be low risks to retailer viability and competition in the event we underestimated wholesale costs.
- it is reasonable for the DMO wholesale cost component to involve some price risk for retailers. A setting where forecasts are rarely or never underestimated means that our forecasts will overestimate many retailers' wholesale costs.

[34] ACIL Allen Consulting, 19 April 2021, Default Market Offer 2021–22 Wholesale Energy and Environmental Costs Methodology Paper for DMO 3.

A lower price point could better reflect hedging practices across retailers.

Question 17: Does the 95th percentile hedged WEC estimate remain appropriate, in context of the hedging strategy? What alternative percentile could be applied and what would the justification be?

5.3 AEMO Directions costs

During DMO 3, a stakeholder submitted that our wholesale cost forecast should include AEMO Directions costs.[35] AEMO issues directions to generators when it considers the market response is inadequate to maintain a reliable and secure power system, or in response to unexpected events.

We determined that it was not appropriate for AEMO Directions costs to be included in DMO 3 because:

- under the indexation approach, including a new cost would impact the comparability and consistency of the index, involving recalculating the residual from DMO 1
- the need for future AEMO Directions may be mitigated with the commissioning of synchronous condensers (scheduled in July 2021).

AEMO Directions costs have been incurred to a small extent since July 2021. This may be due to the delayed commissioning of the synchronous condensers beyond the July 2021 target.[36]

We will continue to monitor AEMO Directions costs in the coming period. As we are reviewing different elements of the methodology, and directions costs appear to be an ongoing cost faced by retailers, our preliminary view is that it would be reasonable to take these costs into account in DMO 4 and future forecasts.

35 AGL Energy, Submission to DMO 3 Position Paper, 19 November 2020, p. 3–4.

36 ElectraNet website, accessed 7 September 2021, see: https://www.electranet.com.au/what-we-do/projects/power-system-strength/

6 Environmental costs

Environmental schemes applied by Federal and State governments require retailers to procure electricity from renewable sources and improve customer energy efficiency. The costs of these schemes are incurred by retailers and recovered through retail prices. Environmental costs fall into 2 main categories — the national Renewable Energy Target (RET) scheme, and jurisdictional green schemes.

The majority of environmental costs relate to complying with the RET. Retailers have an obligation to purchase renewable energy certificates and surrender them to the government in proportion to the overall amount of energy consumed by their customers.

The RET is made up of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). LRET costs are incurred in acquiring 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.[37] 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).[38]

In addition to the RET costs, a retailer typically also passes through jurisdictional scheme costs. These schemes include 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 South Australian 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 South Australian Retailer Energy Efficiency Scheme (REES), retailers incur costs directly and pass them on to their customers.

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

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

6.1 Environmental cost forecasting methodology

Consistent with the market based approach to forecasting wholesale costs, the environmental cost forecasting methodology takes a market based approach to estimate RET costs. Our approach includes 3 steps to estimate RET costs:

- Estimate the RPP and STP – Consider actual values of the renewable percentages (RPP and STP) for the calendar year in which the DMO financial year commences, which would be published by the CER in March, and estimate values for RPP and STP for the following calendar year.
- 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.
- Estimate RET – Compute RET costs for the relevant calendar years by multiplying certificate prices with renewable percentages, and averaging the 2 calendar years to derive the costs for the relevant DMO financial year.

LGC prices are calculated based on a volume weighted average calculated from when trading began. We consider this methodology is robust as it takes into account the entire time period in which LGC trades have occurred.

The jurisdictional energy efficiency schemes, and network losses (that impact environmental cost forecasts) vary between distribution regions. These were estimated from a variety of sources, such as NSW ESS and South Australian REES published information, and AEMO Loss Factors reports.

Stakeholders have generally supported the market based approach to forecasting LGC costs, and using consultants to estimate the STP used to determine SRES compliance costs.

Over subsequent DMO determinations we have considered arguments about whether we should consider the cost of LGCs derived from Power Purchase Agreements (PPAs). Our position has been:

- market traded LGC prices are transparent, publicly available and a function of market conditions, and are the best available proxy for the cost of acquiring LGCs
- market traded LGCs are highly liquid, with brokered forward contracts representing a large proportion of the required surrender amount each year
- there are significant challenges in reconciling an approach using historical LCG prices from PPAs with a forward-looking DMO approach, and noting that the cost of LGCs derived from PPAs are not transparent
- our market based approach to estimating LRET costs is also adopted by other Regulators, including the QCA and ESCV.

Our preliminary view is that the existing methodology to forecast environmental costs is transparent and appropriate for use in DMO 4 and future determinations. We have not seen information suggesting we need to change our approach, or that the approach is no longer meeting stakeholders' expectations. While we are open to considering new information and arguments on this matter, our initial position is that the existing market based approach continues to be best suited to estimating environmental compliance costs incurred by retailers.

Question 18: Do you agree with the appropriateness of our environmental cost forecasting methodology for DMO 4?

7 Network costs

Network costs in a retail electricity bill represent the cost of transporting electricity through transmission and distribution networks, and the cost of meters operated by network businesses to measure customers' electricity consumption. In some regions, network costs also include a component to recover the cost of jurisdictional schemes.

Under the National Electricity Rules (NER), the AER regulates network charges. The distributors set network charges under a range of tariff structures for each class of customer annually.

The DMO price is adjusted each year to reflect changes in network costs for the relevant customer classes.

7.1 Methodology

In setting the DMO price, we generally calculate network costs based on approved tariffs, though in some cases when that is not available due to timing differences, we use distributors' submitted tariffs for the relevant DMO period. This information is generally provided through annual pricing proposals. However, when a distributor commences a new regulatory period we have used indicative pricing proposals from the previous year.

In previous determinations we based the network cost component of the DMO on network charges for customers on flat rate tariffs. A separate network cost amount is calculated for each DMO customer class.

Issues for consideration

As part of this review of our DMO methodology, we have identified 2 key matters to explore in relation to estimating network costs.

- Should we extend our analysis to capture costs under TOU tariffs for residential customers?
- Should we 'true up' network costs to reflect differences between estimated and actual network charges in previous periods?

In determining an approach to network costs for DMO 4 we seek stakeholder feedback on these issues.

7.2 Use of TOU tariffs in network cost assessment

The DMO 1 decision only applied to flat rate customers. However, the DMO framework was extended to apply to residential TOU customers from DMO 2 onwards. We continued to base our assessment of network costs for residential customers on flat rate network tariffs.

We justified this position based on analysis completed as part of our DMO 2 decision that showed that network costs were not significantly different for flat rate and TOU residential customers using our selected electricity consumption profile. Also, the majority of residential customers remain on flat rate tariffs.

According to information provided by retailers as part of our DMO 3 consultation, as at 30 September 2020, up to 24% of all residential customers (and up to 18% of standing offer residential customers) were on a TOU retail tariff, depending on region.

In previous DMO consultations, retailers have noted that because network and metering costs to serve are typically higher for TOU customers, the costs should be reflected in the DMO price.

Table 7.1 compares network prices in 2021–22 for flat rate and TOU residential customers in DMO regions under usage assumptions applied in DMO 3. This analysis excludes metering costs, which are typically higher under TOU network tariffs (metering costs are discussed separately below).

Annual network costs are within $10 across flat rate and TOU tariffs in the Ausgrid, Endeavour Energy and Energex distribution regions. There is a larger difference in the SAPN and Essential Energy distribution networks, with annual costs significantly lower under TOU network tariffs. This analysis applies the same simple load profile for estimating annual costs under TOU retail offers for comparison against the DMO price. As such, it may not reflect expected outcomes for customers on these tariffs.

Table 7.1 Network costs under flat rate and TOU tariffs

Region	Network costs (excluding metering) Flat rate tariffs	Network costs (excluding metering) TOU tariffs
Ausgrid	$527.53	$518.90
Endeavour Energy	$599.67	$601.25
Essential Energy	$914.61	$799.08–811.87
Energex	$634.85	$642.04
SAPN	$793.34	$763.31

Source: Network business Annual Pricing Proposals for 2021–22.

The following discussion covers the options of:

- retaining an approach of limiting the network cost assessment to flat rate tariffs
- expanding the network cost assessment to include TOU tariffs.

Option 1 – continue to base network costs on flat rate tariffs

The DMO price is designed to, among other objectives, cover the costs of serving the customers to which it applies. For residential customers, the DMO applies to standing offer customers on flat rate or TOU network tariffs. As the majority of customers (and particularly standing offer customers) remain on a flat rate network tariff, it can be argued that a DMO based on flat rate network tariffs would result in the most representative price. Under this approach most standing offer customers on the DMO price would have an electricity price that reflects their underlying costs.

This approach, however, will result in a DMO price that is less representative for those customers on a TOU network tariff and means that retailers are exposed to variations in costs across different tariffs.

The DMO also has a role as a reference price to compare market offers. An approach that excludes assessment of TOU network tariffs may distort market behaviour. For example, if TOU network costs are higher, retailers may be less willing to promote offers that would lead to a customer switching from a flat rate to a TOU network tariff (such as might occur if the offer required the customer to install an advanced meter).

In practice, we expect there is little difference in costs under flat rate and TOU network tariffs for a typical customer in the short term. In designing tariff structures, distributors must take into consideration the impact of changing tariffs on customers. This pricing principle should limit large cost changes in individual tariffs, or differences across tariff classes that customers are likely to transition between.

The current approach of basing our assessment of network costs for residential customers on flat rate network tariffs has the advantage of simplicity. In particular, it requires fewer assumptions around electricity usage behaviour of a typical customer than other options. This should result in more robust estimates of annual customer costs.

Given the broader electricity market policy objective of moving customers to more cost-reflective network tariffs, it is expected that TOU tariffs (or other more flexible tariff options) will become more common for residential customers over time. As such, if we retain the current approach of using flat rate network tariffs for DMO 4, we will need to determine the point at which TOU network tariffs should be included.

Option 2 – include TOU network tariffs in cost assessment

As the DMO applies to customers on a range of network tariffs, it may be reasonable that the costs faced by these customers are reflected in the DMO price.

If TOU network tariffs are excluded from the DMO price setting approach, we risk the DMO not reflecting the underlying costs of customers on those tariffs. This risk will increase as the proportion of residential customers on TOU network tariffs rises.

The network cost assessment under the DMO could reflect costs under a range of network tariffs by weighting the cost under each tariff by the number of customers on them. A simple weighting could be used across all relevant DMO jurisdictions or set for each jurisdiction reflecting the different rates of TOU uptake across regions.

Weighting each tariff by customer numbers means that the network cost estimate will reflect changes in tariff adoption over time. This will avoid the need for ongoing assessments of whether flat rate network tariffs remain broadly representative for residential DMO customers. While the cost estimate under this approach may be less reflective of a 'typical' DMO customer, it will better capture the average cost of supplying all DMO customers.

A key consideration in a decision to include TOU network tariffs in our network cost assessment is whether we can accurately assess annual costs under these tariffs. The DMO includes a simple daily load profile for retailers to use in comparing TOU retail offers against the DMO price. While we consider this remains appropriate for the purpose of comparing market offers, it may not be sufficiently robust to use as the basis for assessing changes in costs that make up the DMO price. The assumptions in the load profile can have a significant impact on the estimated annual cost.

Question 19: Should the calculation of network costs for residential customers continue to be based on flat rate tariffs only? If yes, as what level of TOU tariff penetration should this approach be reassessed?

Question 20: If TOU network tariffs are included in our assessment, should we use a simple weighting of customers on each tariff type across all jurisdictions, or a separate weighting for each network area?

Question 21: Is the DMO daily load profile (provided to retailers to calculate annual market offer costs for TOU offers) sufficient for calculating annual TOU network costs?

Question 22: Should we assess metering costs separately from network costs?

7.3 True-up network costs

In previous DMO determinations, we have considered the issue of whether to retrospectively adjust the DMO price to account for variations between our forecasts and actual costs that eventuate.

In the context of the DMO indexation approach, we have not made any such adjustments. Our key reasons for this have been:

- the DMO is a forward-looking instrument, and should be set at a level that reflects our best estimate of costs for the relevant period
- the DMO price is not intended to be an accurate reflection of retailers' efficient costs, and is set sufficiently high that an underestimation of costs should not impact the DMO achieving the policy objectives.
- 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

Applying a true up would mean that the DMO no longer reflects expected prices in any given year. This adjustment would result in the effective 'DMO allowance' being smaller (or larger) in the period where the true-up occurs where costs have been underestimated (overestimated). This would also mean that the DMO price is less effective as a comparator price. True-ups would lead to more variation across years in the level an efficient retailer could discount from the DMO price. This has the potential to create unnecessary consumer confusion.

True-ups will affect standing offer customers in a later period than where the costs were incurred. These customers may not be the same as in the previous period. This raises a question of equity as to whether it is appropriate to recover (rebate) these costs from standing offer customers in these circumstances.

In DMO 2 and DMO 3, some retailer stakeholders considered it unreasonable that retailers not be compensated for pass through costs they had no control over. For example, Origin Energy noted that not compensating for these costs was inconsistent with the principle that retailers should be allowed to recover an efficient cost allowance.[39] Retailers highlighted network costs in particular were a concern. In DMO 2, the forecast network costs used to calculate the DMO underestimated actual costs. Despite these concerns, Origin offered market contracts at prices well below the DMO price in each region across 2020–21. This suggests that there remained enough allowance in the DMO price to absorb costs not specifically incorporated in the DMO price.

We note that the likelihood of approved prices not being available for our final DMO calculations will be significantly lower in the future. This is because the AER's Network pricing team is introducing new streamlined processes, which should reduce the time between receiving annual pricing proposals and the AER Board consideration. Additionally, DISER's review is considering amending the final date for DMO determinations

The potential for actual network costs to vary from estimates available at the time of the DMO decision are highest in years where a distributor is commencing a new regulatory determination period (a reset year). Approved network prices in reset years are generally not available until July, well after our deadline for finalising the DMO price.

We welcome stakeholder views on how to approach network cost estimation in reset years, but do not intend to reach a firm position on this issue at this time as it is not relevant to the DMO 4 period. The next reset year for a DMO jurisdiction is 2024–25 (for the NSW distribution networks).

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[39] Origin Energy, *Submission to DMO 3 Position Paper*, 19 November 2020, p.2-3.

Our preferred position remains to not adjust DMO prices for any variance between actual and forecast network costs in the previous period. We consider that the DMO objectives are best met by the DMO price reflecting the best estimate of costs in the relevant period.

Question 23: Do you agree with our preferred position to not true up network costs in calculating the DMO price?

8 Advanced meter costs

Accumulation meter costs are recovered by distributors through network charges. The Power of Choice reforms in 2017 gave retailers responsibility for managing advanced metering installations, and they incur associated costs.

The DMO price does not include a specific allowance for advanced meter costs, and each additional advanced meter installation introduces a cost to retailers that is not fully reflected in the DMO network cost component. Retailers have argued that without an allowance in the DMO price for this additional cost, they are compelled to recover it from market customers, in essence eroding the profitability of each customer and undermining the objectives.

The residual DMO cost component was originally established based on fixed rate standing and market offer prices in October 2018. We assume these offer prices covered advanced meter costs for the customers on these offers.

Over time, the proportion of advanced meters and associated costs in DMO regions will increase because advanced meters must now be installed when:

- current accumulation meters reach the end of their rated service life, or are replaced due to faults
- customers install solar PV and/or batteries or elect to move to TOU retail tariffs
- new connections to the NEM are established, such as new residential or commercial developments.

In the DMO 2 and DMO 3 determinations, we assessed additional retail costs under the step change framework. Some retailers provided confidential evidence that annual advanced meter costs are greater than accumulation meter costs included in the network cost component of the DMO price.

We also obtained information on the number of advanced meters installed for different customer groups from the 10 largest retailers by market share in DMO regions.

Based on analysis of this data we were satisfied that while the proportion of advanced meters had increased since October 2018, there was sufficient margin in the DMO residual for retailers to absorb these additional costs and still make a reasonable profit.

However, our consideration of different options for establishing the residual cost component in this review re-opens the question of advanced meter costs, and whether the DMO price should reflect these:

Broadly speaking, we consider there are 2 options:

- include some advanced meter costs in the DMO price, in line with the proportion of customers with advanced meters
- not include any advanced meter costs in the DMO 4 determination, on the basis that costs are not material or captured in other components of the DMO.

To inform our consideration of this question we have requested retailers provide information about advanced meter installations for standing and market offer customers on fixed rate and TOU offers. We will also consider advanced meter cost estimates produced by jurisdictional energy regulators and rule making authorities.

We will use the data to determine advanced meter costs, consider how they are recovered by retailers, and the extent of any interaction between standing offer and market offer customers for advanced meters.

We will also consider the issue of advanced meter cost alongside the calculation of the network cost component. The network cost component includes a metering allowance for accumulation meters. It is possible retailers are currently being partially compensated for advanced meter costs by the accumulation meter cost allowance in the Network cost component.

8.1 Option 1 – Provide an advanced meter allowance

While the penetration is currently relatively low in DMO jurisdictions, this proportion will continue to grow. Accordingly, the costs to retailers will continue to grow over the proposed 3 to 5 years this DMO methodology is applied. Between 2016 and 2020 we observed smart meter adoption across the NEM (excluding Victoria) increase from 2% to 20%.[40]

It may be reasonable to include some of these costs in the DMO price because:

- they are an unavoidable regulatory cost.
- while costs may be low now, they are likely to become material at some point in the near future. Over the lifespan of the DMO methodology, these may impact the DMO objectives if the costs were not reflected in the DMO price.
- most retailers absorb these costs and smear them across the customer base, essentially reducing the amount of profit per customer. Some retailers have argued that if the DMO price does not reflect this cost, it may act as a disincentive for retailers to roll out advanced meters. This would reduce or delay the intended policy benefits of the Power of Choice reforms. We agree that this outcome would not be in the interests of consumers.

Given the current relatively low level of advanced meter penetration, simply applying the full cost of an advanced meter to the DMO price would be unfair to the large majority of customers without advanced meters.

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40 AEMC, Review of the Regulatory Framework for Metering Services Consultation Paper, 3 December 2020, p. 19.

A more equitable option may be to include costs on a proportional or weighted basis each year, consistent with the proportion of customers in DMO regions with advanced meters.

This would mean the impact of including advanced meter costs on the DMO price would initially be smal, and would increase incrementally each year. The cost of advanced meters would also be assessed with each DMO, to ensure we capture cost savings and efficiencies resulting from economics of scale.

Network cost considerations

The network component of the DMO price includes some metering costs. As with other network costs, these are currently based on flat rate customers.

When a customer moves from an accumulation meter to an advanced meter, their retailer becomes responsible for the associated costs and generally stops paying metering costs to the DNSP.

In determining any annual allowance for advanced meters in the DMO price, we would need to account for this avoided cost.

In our view, a reasonable approach would be to determine a net cost per advanced meter customer by deducting the network metering costs from the estimated advanced meter cost.

From this net cost we would then determine a weighted cost for the region, based on the proportion of customers with advanced meters. This would be included in the retail cost or residual component (depending on the approach we adopt). The example below sets this out.

An advantage of this approach is that we would not need to change our current approach to calculating network costs, which is preferable for consistency and transparency.

Advanced meter allowance example

The below sets out an example of how an advanced meter allowance could be calculated and applied under our proposed approach.

The AEMC's *Review of the regulatory framework for metering services* consultation paper[41] showed that advanced meter take-up across the DMO regions is as follows:[42]

- Ausgrid: 16%

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41 AEMC, Review of the Regulatory Framework for Metering Services Consultation Paper, 3 December 2020, p. 17.

42 AEMC, Review of the Regulatory Framework for Metering Services Consultation Paper, 3 December 2020, p. 20.

- Endeavour: 20%
- Essential: 18%
- Energex: 17%
- SAPN: 18%

To date, retailers have not provided information that would allow us to assess their costs to serve customers with advanced meters. In part, this is due to the contractual and commercially sensitive nature of the information.

In previous DMO determinations we have noted ACIL Allen Consulting estimated an annual cost of around $120 for the Queensland Competition Authority, encompassing installation and ongoing costs.[43] In comparison, the annual distributor metering charges for Ausgrid in DMO 3 are around $26.

To calculate metering charges under this proposed approach, we would:

- deduct distributor metering charges from advanced meter costs – net advanced meter costs
- multiply the net advanced meter costs by the proportion of customers on advanced meters in the relevant DMO region.

For example, using the above information, we could calculate advanced metering cost allowance for Ausgrid to be: $(\$120 - \$26) \times 16\% = \$15.04$

The calculated cost above is on a per customer basis and would be added on to the residual component of the DMO price. For this example, this means a $15.04 allowance for advanced meter costs in the Ausgrid region.

8.2 Option 2 – Do not include advanced meter costs

Given our position of setting the DMO price at a level that balances the DMO objectives, is it is likely that retailers can absorb a $15 cost per customer for advanced meters (based on the estimates above) without impacting their ability to make a profit or recover their costs.

At current levels of advanced meter penetration, the cost impact is still not material and could continue to be excluded from the DMO price.

As noted above, however, these costs will increase each year, and may well become material in a future DMO year. In this scenario, it is possible advanced meter costs may impact the DMO objectives.

43 ACIL Allen Consulting, *QCA Benefits of Advanced Digital Metering*, September 2019, p.7.

As such, if we retain the current approach of not including advanced meter costs for DMO 4, we will need to determine the point at which these costs should be included.

Question 24: Should the DMO 4 methodology include an allowance for advanced meter costs? And if so, is the proposed approach above viable to calculate and account for its cost?

9 Model annual usage and TOU determination

Under Part 3 of the Regulations, we are required to determine 'broadly representative' annual supply (usage) amounts for residential and small business customers in each distribution region, from which a DMO price and reference price can be calculated. We must also determine the timing and pattern of supply to residential customers.[44] The Regulations refer to these elements in combination as the 'model annual usage'.

This chapter discusses options for updating our annual usage amounts, and the daily usage profile used to compare TOU offers against the DMO price.

We opted to retain the annual usage amounts established in DMO 1 for our DMO 2 and DMO 3 determinations, as we considered the benefits of retaining the same usage amounts for the purpose of making price comparisons between years outweighed the benefits of changing the usage amounts incrementally to reflect changes in usage.[45]

After 3 years, it is appropriate to consider whether our usage amounts remain broadly representative. New information to enable us to update the annual usage amounts as part of this methodology review includes data on residential and small business annual usage from ACCC reports for its *Inquiry into the national electricity market,* and updated consumption information from distributors.

9.1 Annual usage determination

As part of this methodology review, we intend to update the annual usage figure for each customer type and region, to ensure these are broadly representative.

While we are required to set a single usage amount for each region and DMO customer type, we acknowledge this will not be representative of the usage of many consumers in the region. Given the aim of the DMO reference price is to provide a general point of comparison, it is appropriate for us to set a usage amount that generally reflects a significant proportion of customers.

To achieve this outcome, we intend to consider a range of factors.

Our consideration of issues and options is set out below.

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

45 AER, *Default Market Offer prices 2020–21*, Final report, April 2020, p. 56; AER, *Default Market Offer prices 2021–22*, Final report, April 2021, p. 63–64.

Residential customers

For DMO 1, we calculated annual usage for residential customers on flat rate tariffs based on estimated consumption data from distribution network businesses contained in annual pricing models for 2018–19.

This data identified residential consumption within a distribution area. It was the most recent data available and was reliable – being data from regulatory distribution determination processes.

We also calculated controlled load usage for residential tariffs with controlled load. In most cases we were able to ascertain this from the 2018–19 annual pricing models, but in some cases the information was not provided. In these instances, we either sought the information directly from distributors, or referred to the residential consumption data collected by ACIL Allen for the AER's 2017 Energy Consumption Benchmark project.

To understand current residential annual usage amounts we have requested consumption information from distributors for 2020–21, as well as 2018–19 and 2019–20. This information includes average consumption amounts of customers on different network tariffs, and for some customer types the median and interquartile range. This level of detail will allow us to examine typical consumption amounts, as well as the range in consumption within different customer types, and the change in consumption since the first DMO.

We propose to also consider other information to assist in distinguishing usage for different customer and tariff types, including:

- the ACCC Inquiry into the National Electricity Market September 2020 and May 2021 reports. The reported figures will assist us to cross check distributor estimates. We note the reports provide usage figures for states rather than distribution regions, so we cannot cross check the individual NSW distribution region figures
- AER usage data obtained for the purpose of updating annual bill benchmarks.[46] This data provides a useful additional reference point, though we note the small sample sizes included make it a less reliable indicator.

We will set out draft annual usage amounts in our Draft Determination for DMO 4.

Question 25: Do you support our use of DNSP data, cross-checked with other sources, to determine residential annual usage?

[46] The bill benchmarks are referenced in customer bills and used by the Energy Made Easy price comparison website to generate annual energy price estimates.

Small business customer usage

In DMO 1, we adopted an annual usage figure of 20,000 kWh, consistent with published information by the ECA.[47] We recognised the large variability in small business consumption due to the varying nature, size, and location of small businesses, and adopted the ECA figure as the best available estimate at the time.[48] However, we recognise that a single consumption figure cannot be considered to represent all small business customers.

In its 2020 *Inquiry into the national electricity market* final report, the ACCC observed median annual usage for small business market offer customers between 1 July 2018 and 1 December 2019 was close to 8,000 kWh across Victoria, NSW, south-east Queensland and SA.[49] The ACCC also noted large variations in electricity usage because of the diverse range of business types and sizes regarded as small businesses.

It observed the middle 50% of small business customers (the interquartile range) used between just under 2,500 kWh and just over 17,500 kWh of electricity.[50]

The ACCC's 2021 Inquiry into the national electricity market report observed small business usage had decreased due to the influence of COVID-19 by an average of 17% by mid-2020.[51]

The ACCC data showed that the annual usage amount of 20,000 kWh we adopted for our previous DMO determinations more closely reflects the amount used by the top 25% of small business customers.[52]

While the ACCC data confirms our 20,000 kWh usage figure is not unrepresentative of small business usage, this methodology review provides an opportunity to review the amount and revise it downwards.

If we adopt a lower usage figure, the DMO price will be more representative of lower users, and less representative of higher users. Our initial view is that it would be appropriate to use the lower figure as this would represent a larger number of small business users.

We are interested in stakeholder views on the options outlined below.

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47 AER, *Default Market Offer prices 2019–20*, Final report, April 2019, p. 64.

48 AER, *Default Market Offer prices 2019–20*, Draft Determination, February 2019, p. 69.

49 ACCC, *Inquiry into the National Electricity Market*, September 2020, p. 40–41. The National Electricity Market includes non-DMO jurisdictions (Victoria, the ACT and Northern Queensland).

50 ACCC, *Inquiry into the National Electricity Market*, September 2020, p. 12.

51 ACCC, *Inquiry into the National Electricity Market*, May 2021, p. 12.

52 ACCC, *Inquiry into the National Electricity Market*, September 2020, p. 41.

Option 1 - Apply a single figure of 10,000 kWh for small business usage in all DMO regions

Using the ACCC data as a guide, we could revise small business annual usage down to a rounded figure of 10,000 kWh. 10,000 kWh is within the ACCC's calculation of the middle 50% of annual usage, though is not the median.

The ACCC median includes Victoria, and the median applicable to the 3 DMO jurisdictions may vary. Moving away from the ACCC reported median and gravitating to the rounded figure of 10,000 kWh acknowledges the ACCC figure is not representative of the DMO jurisdictions specifically.

It also acknowledges the large variability in small business usage, and that the usage amount we adopt for the DMO is not intended to be an accurate reflection of small business usage, but rather seeks to be broadly representative of customer usage.

Given we intend the usage estimate to remain consistent for some years, our initial view is that the round figure of 10,000 kWh would be suitable as a broadly representative usage benchmark, while the ACCC's median figure may vary from year to year.

Question 26: Do you support applying a single figure of 10,000 kWh for small business usage across all DMO regions?

Option 2 – use the ACCC reported medians for NSW, south-east Queensland and SA to represent small business usage in the relevant states

Adopting the ACCC's individual medians as the small business annual usage figures would make DMO prices more representative of small business customers than they would be if we applied a single usage amount across all DMO regions.

However, given small business usage experiences large variability, adopting differentiated medians for each jurisdiction may give a false sense of accuracy.

Also, using the median values may create an expectation we would keep it updated and revise it whenever updated information on the median becomes available, to ensure it continues to represent the current median value.

Given the key purpose of the DMO to facilitate price comparisons and simplify the process of identifying the best available offer for customers, we consider updating the usage is less important than retaining a stable basis for comparison across years. Therefore, this is not our preferred option.

Question 27: Do you support applying individual ACCC reported median usage figures in NSW, SA and south-east Queensland? If so, please outline the advantages of this approach.

Impact of COVID-19 on annual usage

In its May 2021 *Inquiry into the national electricity market* report, the ACCC observed residential usage increased on average by 10% across the national electricity market in 2019–20, due to government policies to stop the spread of COVID-19, which meant residential customers spent more time at home.[53] The ACCC also noted some differences in regional trends which it ascribed to the differing severity of lockdown measures in each State.

The increase in demand was a reversal of the trend in recent years of reducing residential demand due to increasing appliance efficiency and uptake of rooftop solar systems.[54]

We recognise lockdown measures may continue to be employed to stop the spread of COVID-19, and if so, higher annual usage for residential customers can be expected to continue. We also note changes in demand due to the COVID-19 related restrictions are highly dependent on the location and duration of lockdowns which are unpredictable. Even without more lockdowns, we are unlikely to see a full return to previous consumption trends as home-based work becomes standard practice for some people.

Option – use an average across 3 years of data to incorporate recent changes in annual usage

Given the ongoing social impacts of COVID-19 and the consequences for increasing residential usage, we consider it appropriate to reflect the effect on residential annual usage.

COVID-19-related lockdown effects are also unpredictable and can vary due to the extent and severity of lockdowns, with the potential to create volatility in the data. Our initial view is that averaging across 3 years of data would better represent usage over a number of years.

This provides a means to reduce variability in the data, and establish usage figures that remain broadly representative of customer usage for a longer period of time.

We previously employed this approach to establish the TOU daily usage profiles, to reduce volatility to establish broadly representative profiles.

Question 28: Do you support averaging across 3 years of data to calculate annual usage?

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[53] ACCC, *Inquiry into the National Electricity Market*, May 2021, p. 12–13.

[54] ACCC, *Inquiry into the National Electricity Market*, May 2021, p. 14.

Annual usage considerations for TOU customers

The Regulations require us to set a single usage amount for each customer type – residential, residential with controlled load, and small business (no controlled load).

As noted above, residential usage has been based on flat rate customers only. While the large majority of residential customers are on flat rate tariffs, the number of customers on TOU tariffs is likely to increase as the industry progresses towards cost reflective network and retail pricing.

In preparation for our DMO 4 Draft Determination we intend to consider whether the annual usage amounts should reflect any differences in annual usage between flat rate and TOU customers.

We will consider the usage of TOU customers as part of our data request from network businesses.

One option may be to reflect any different usage by TOU customers, based on the proportion of customers on TOU retail tariffs.

If there was a difference (for instance, if TOU usage was higher), this may have implications for the usefulness of the reference price. In particular, the reference price would be less representative of flat rate customers, who comprise the large majority of residential customers.

Question 29: Would you prefer we reflect TOU usage in annual usage estimates, or calculate annual usage based on flat rate usage, given most customers are flat rate customers?

Embedded network customers

If DISER extends the DMO to embedded network customers, we would need to consider the annual usage of this group. We estimate there are more than 74,000 embedded network customers serviced by authorised retailers. This constitutes about 2% of customers in the DMO regions.[55]

Our consideration of embedded network customers in relation to setting the annual price and model annual usage would depend on the final form of any amendments to the Regulations. For example, our approach would need to be different depending on whether the Regulations created a separate customer type, or included them in the existing residential and small business categories.

[55] Based on internal AER figures.

Given the timing of the DISER review, this Options Paper sets out some of our initial consideration of applying the DMO price cap to embedded network customers. We intend to discuss these issues in greater detail in our Draft Determination.

At that stage, our views will be informed by stakeholder feedback to DISER's review, as well as the proposed regulatory amendments set out in DISER's exposure draft, expected to be released later in 2021.

Our preliminary view is that the annual usage of a retail market residential or small business customer would be broadly the same as an equivalent embedded network customer of a similar type and size. We would welcome any information about the usage of embedded network customers.

9.2 Timing and pattern of supply

The Regulations require us to determine the timing and pattern of supply of usage for each DMO region over a year.

This part of our DMO determination covers how the annual usage is divided over a year, including within each day. In practice, the key elements have been:

- our assumption that usage for all customers will be the same on each day of year, with no variation for seasonality or weekend usage difference
- the daily TOU profiles, first developed for our DMO 2 determination and refined in our DMO 3 determination to reflect half hourly intervals
- for the SAPN region, a daily usage profile specifying usage at half-hourly intervals for the SAPN TOU controlled load tariff.

We consider the timing and pattern of supply determination that evenly divides usage across the year is effective and simple, and we intend to retain it. Stakeholders supported this approach in DMO 3.

Stakeholders also supported the daily half-hour profiles as a balance of accuracy and simplicity. While we do not propose to change the structure of these profiles, we propose to update the information to ensure it is reasonably representative of current usage patterns, noting that no pattern can represent all customers.

Updating the DMO TOU profiles

It is possible that daily usage patterns have recently changed for residential customers.

For example, with customers spending more time at home they may allocate usage more equally throughout the day or may have greater discretion to move non-essential usage to off-peak periods.

These arrangements are likely to continue in the medium term with COVID-19 related lockdown measures continuing to be employed. Therefore, any changes in intraday usage patterns are likely to continue to some degree, and we consider it important to update the TOU daily profiles to reflect any recent changes.

By specifying the amount of energy usage at half hourly intervals, the current profiles provide a consistent basis to calculate DMO prices for TOU offers, while affording retailers flexibility to determine their own pricing periods.

We propose to maintain the profiles in their current form and update them with recent interval meter data from AEMO.

To reduce the influence of particular events on the data and better represent average usage patterns, we propose to average across 3 years of data as we did in updating the usage profiles for DMO 3.

Question 30: Do you support updating the usage profiles by averaging across 3 years of usage data?

The AEMO interval meter data we used to calculate the DMO 3 daily usage profile incorporated TOU and flat rate usage, producing profiles that blended usage patterns for TOU and flat rate customers.

Given the profiles are only relevant to TOU customers, a blended profile may be less representative of these customers than one solely based on TOU customer usage. This is because the peak and off-peak pricing in TOU tariffs is designed to encourage users to change when they use electricity. Customers who respond to these price signals may use less in peak periods, and more in off-peak periods.

Profiles based solely on customers TOU usage data would be more representative for these customers. However, it would not be straightforward to develop these because retail TOU customers are not identified in the AEMO MSATS data. We would need to ask retailers for this data and would have to weigh up the consumer benefits against the additional regulatory burden for retailers.

Our preliminary view is that these benefits are likely to be marginal, given that the current TOU profiles are highly generalised and do not account for different seasonal or weekend use.

In the context of our requirement that the profiles be ‘broadly representative’, our preliminary view is that a ‘blended’ TOU and flat rate usage profile is reasonable and consistent with the requirements of the Regulations.

We are interested in stakeholders’ views on this question.

Question 31: Do you support maintaining the profiles based on a mix of TOU and flat rate offers?

Appendices

Appendix A – List of stakeholder questions

Appendix B – Proportion of standing and market offer customers

A List of stakeholder questions

The questions posed throughout this Options Paper are listed below. To see the context for each question, refer to the in-text discussion at the page numbers listed in brackets at the end of each question.

- Question 1: What is the most appropriate approach to estimating retail operating costs under a cost based approach? (23)
- Question 2: What information should we have regard to in estimating retail costs? (23)
- Question 3: What are the impacts on retailers facing a time lag for recovery of retail costs? (24)
- Question 4: Is the DMO protecting customers from unjustifiably high prices? If so, why? (28)
- Question 5: What factors are relevant in considering whether a price is excessive? (28)
- Question 6: What other factors should we consider when assessing the DMO allowance required to incentivise customers to engage in the market? (29)
- Question 7: Should the margin above efficient costs in the DMO price be consistent across all DMO regions and customer types? (31)
- Question 8: What is an appropriate DMO margin to achieve the policy goals? (31)
- Question 9: Should we continue indexing the current residual? (34)
- Question 10: What are the benefits and disadvantages of this approach? (34)
- Question 11: How could the step change framework be improved? (34)
- Question 12: Should we perform an adjustment to reflect movement in retail costs, and if so should this be performed on an annual basis? (35)
- Question 13: How long should we retain the methodology we adopt in this review? (36)
- Question 14: Is our existing wholesale cost forecasting methodology, in terms of its approach and considerations (modelling of demand and supply, spot price, hedging etc.) complete, appropriate and representative of costs to supply energy? (39)
- Question 15: Should our existing assumed hedging strategy be adjusted to allow for a higher level of spot market exposure? And if so, what is the appropriate level of exposure? (please also consider this question in conjunction with Margin for forecast error discussion) (43)
- Question 16: Does our assumption of a 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? (44)

- Question 17: Does the 95th percentile hedged WEC estimate remain appropriate, in context of the hedging strategy? What alternative percentile could be applied and what would the justification be? (46)
- Question 18: Do you agree with the appropriateness of our environmental cost forecasting methodology for DMO 4? (49)
- Question 19: Should the calculation of network costs for residential customers continue to be based on flat rate tariffs only? If yes, as what level of TOU tariff penetration should this approach be reassessed? (53)
- Question 20: If TOU network tariffs are included in our assessment, should we use a simple weighting of customers on each tariff type across all jurisdictions, or a separate weighting for each network area? (53)
- Question 21: Is the DMO daily load profile (provided to retailers to calculate annual market offer costs for TOU offers) sufficient for calculating annual TOU network costs? (53)
- Question 22: Should we assess metering costs separately from network costs? (53)
- Question 23: Do you agree with our preferred position to not true up network costs in calculating the DMO price? (55)
- Question 24: Should the DMO 4 methodology include an allowance for advanced meter costs? And if so, is the proposed approach above viable to calculate and account for its cost? (60)
- Question 25: Do you support our use of DNSP data, cross-checked with other sources, to determine residential annual usage? (62)
- Question 26: Do you support applying a single figure of 10,000 kWh for small business usage across all DMO regions? (64)
- Question 27: Do you support applying individual ACCC reported median usage figures in NSW, SA and south-east Queensland? If so, please outline the advantages of this approach. (64)
- Question 28: Do you support averaging across 3 years of data to calculate annual usage? (65)
- Question 29: Would you prefer we reflect TOU usage in annual usage estimates, or calculate annual usage based on flat rate usage, given most customers are flat rate customers? (66)
- Question 30: Do you support updating the usage profiles by averaging across 3 years of usage data? (68)
- Question 31: Do you support maintaining the profiles based on a mix of TOU and flat rate offers? (68)

B Proportion of standing and market offer customers

Figure C.1 – Proportion of residential customers, 2015–2021

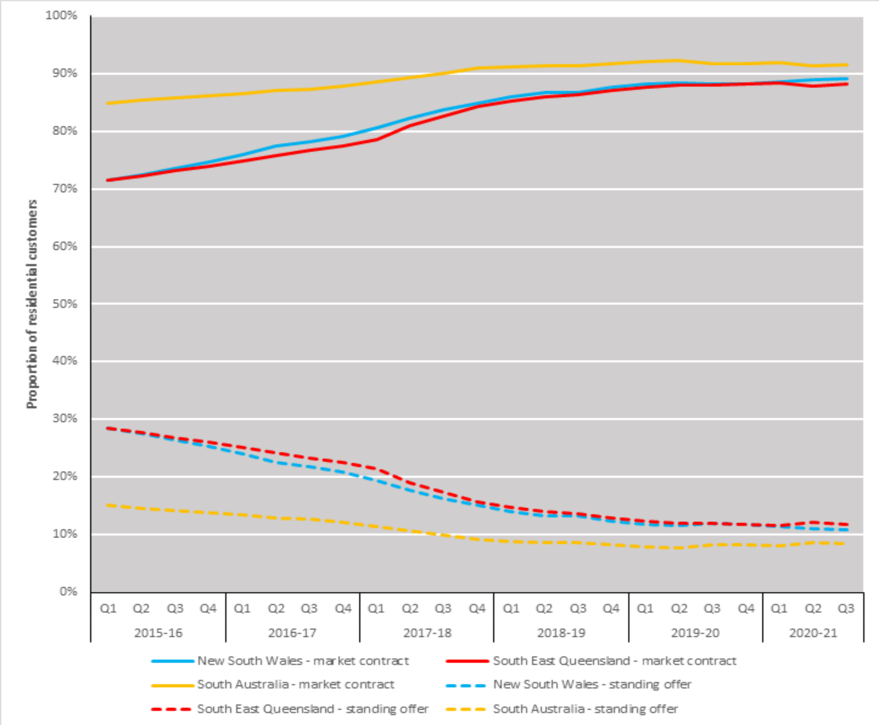

Figure C.2 – proportion of small business customers, 2015–2021