Default market offer prices 2024-25

Issues paper

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AUSTRALIAN
ENERGY
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Contents

Invitation for submissions

Interested parties are invited to make submissions on this issues paper by 3 November 2023.

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 on our use and disclosure of information provided to us, see the Australian Competition and Consumer Commission (ACCC)/Australian Energy Regulator (AER) Information Policy (June 2014).

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
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
DMO 5	Default market offer determination for 2023–24
DMO 6	Default market offer determination for 2024–25
DNSP	Distributed network service provider
ESCV	Essential Services Commission Victoria
EBITDA	Earnings before interest, taxes, depreciation, and amortisation
ICRC	Independent Competition and Regulatory Commission
kWh	Kilowatt hours
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NSLP	Net system load profile
OTC	Over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PV	Photovoltaic system / solar power system
REZ	Renewable Energy Zone

1 The Default Market Offer

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 several reasons – for example, if they have never switched to a retailer's market offer or have defaulted to a standing offer at the end of their market offer benefit period.

The AER's role is to determine the DMO price each year. Our DMO price determination applies to small business and residential customers in South Australia, 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 sets out the legislative framework for the DMO.

The Regulations require the AER to determine a reasonable annual price for electricity. In doing so, we must consider a range of factors including the cost of wholesale energy, transporting electricity and complying with relevant laws. The Regulations require us to have regard to the principle that retailers should be able to make a reasonable profit.

In setting a price that protects standing offer customers from unjustifiably high prices, we are also guided by the policy objectives that it should:

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

The DMO policy objectives remain informed by the recommendations of the Australian Competition and Consumer Commission (ACCC) Retail Electricity Pricing Inquiry[1] and directions from government.[2]

This is the sixth time we will determine DMO prices. As such we refer to the 2024–25 DMO throughout this issues paper as 'DMO 6'. This issues paper is the first step in our process to determine DMO prices.

1.1 Summary of key issues for consultation

During the DMO 5 consultation, we considered changes to our methodology for setting DMO prices. As a result, our DMO 5 final determination incorporated adjustments to our wholesale forecasting methodology and DMO allowances.

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1 ACCC, AER DMO, Submissions to the draft determination, Australian Competition and Consumer Commission, 20 March 2019, pp.1–2.

2 Treasurer and Minister for Energy, *Letter to the AER Chair,* 23 October 2018.

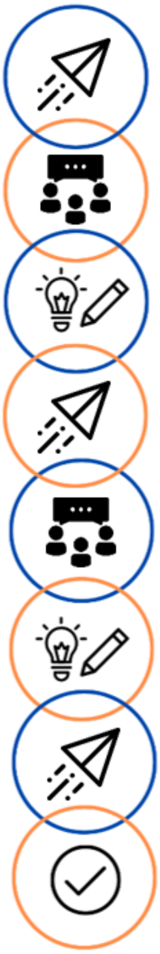
In this issues paper, we seek stakeholder feedback on additional refinements proposed to improve the methodology we will use in DMO 6. Many of these refinements were identified in the DMO 5 final determination and include whether:

- the approach to retail allowances remains appropriate
- and how to change our approach to the customer load profile which is used to model wholesale costs as the uptake of advanced meters and installation of solar PV systems continues
- we should continue collecting confidential hedge contract data from all retailers and generators to assess that the publicly-available data remains a reasonable reflection of this component of wholesale costs
- a different wholesale forecasting method is required for South Australia given the currently limited (and decreasing) hedge contract liquidity levels in South Australia
- to change our methodology for calculating bad and doubtful debts for all customers and the retail operating cost calculations for small businesses, along with other relatively minor issues.

1.2 Next steps

The DMO 6 schedule outlines our time frame and steps for the development of DMO 6 prices.

DMO 6 schedule



5 October 2023
Publish DMO 6 issues paper

Late October 2023
Online stakeholder forum

3 November 2023
Submissions due

Early March 2024
Publish DMO 6 draft determination

Late March 2024
Online stakeholder forum

Early April 2024
Submissions due

Around 25 May 2024
Publish DMO 6 final determination

1 July 2024
DMO 6 applies

2 Market developments since DMO 5 and the environment for DMO 6

This chapter discusses how the retail market has responded to wholesale market events and how ongoing shifts across the supply chain are shaping the environment in which we will make DMO 6.

2.1 State of the wholesale market

The impact of a combination of international and domestic pressures has resulted in unprecedented high prices in the wholesale energy markets in the past 18 months. Following a period of relatively low prices in 2020 and part of 2021 increased spot prices in late 2021 led to rising electricity contract prices. This was due to a combination of factors including generator outages and constraints, fuel supply issues and potential supply shortages, combined with extremely high international coal and gas prices.

Contract prices reached record high levels in mid to late 2022, before easing in October 2022 following conjecture about possible government intervention in the fuel markets. Although contract prices fell sharply in early December 2022 following the announcement of the Australian Government's Energy Price Relief Plan, they remain higher than the lower prices seen in 2020 and 2021.

The wholesale component of DMO 6 uses the volume-weighted-average price of base, peak and cap futures contracts traded for the 2024–25 financial year as a key input in determining a retailer's contracting costs. The mixture of these futures contracts will be dependent on the DMO region's contract market. In South Australia, cap contracts are the most traded contract type. This differs from the other jurisdictions, where cap contracts are typically less than 20% of futures traded. Cap contracts are also more expensive than base futures, so this drives different pricing outcomes across the regions.

Using all futures contracts traded for the 2024-25 financial year results in contracts executed in the period before October 2022 and the relatively high current contracts prices being reflected in the DMO 6 wholesale cost. The chart in Figure 1 uses base futures contracts to illustrate the period of time over which trades for 2024-25 contracts are captured in our methodology. As at mid-September 2023[3] base futures contracts were trading at $104 per megawatt hour (MWh) in Queensland, $112/MWh in South Australia and $126/MWh in NSW. This represents a fall of between 32% and 36% compared with their respective highs in October 2022 but are still approximately double the prices traded in 2021.

These contract prices can provide a guide to the wholesale cost included in DMO 6, however there is still a significant volume to be contracted before the start of the DMO 6 period. The price of these future contracts will be dependent on the supply and demand in the contract market, which can be driven by number of factors including consumption demand, weather conditions, generation outages and fuel availability.

3 Base future prices provided are as of 12 September 2023.

Figure 1 Base future prices for the financial year 2024–25

2.2 Market offer analysis

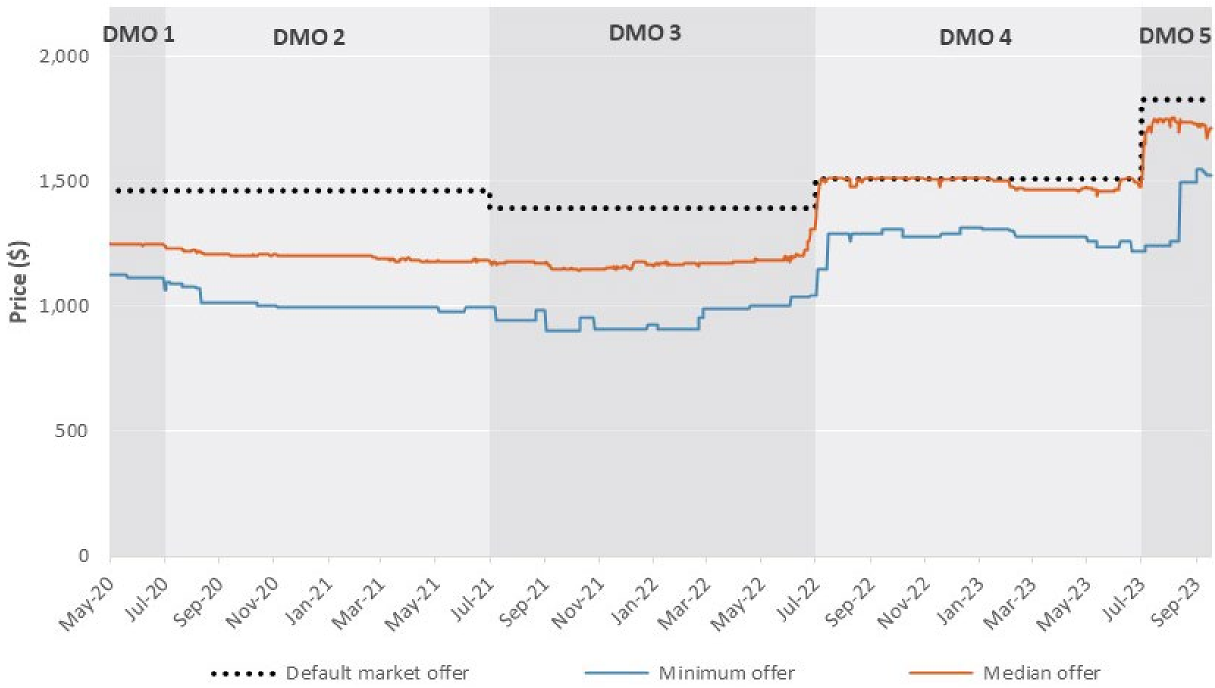
Although the DMO creates a cap on a retailer's standing offer, there are no price caps for their market offers.

Typically, a retailer will price their market offers below their standing offer to attract or retain customers. This was evident in the DMO 2 and DMO 3 periods where the median and minimum market offers were significant discounts from the DMO price. Discounting of market offers from standing offers indicates that retailers can effectively compete and provides an incentive for consumers to engage in the market.

The unprecedented high wholesale prices also had an impact on market offers during the DMO 4 period, as increasing spot prices and record high forward contract prices in mid to late 2022 resulted in retailers adjusting their market offers. During the DMO 4 period there was minimal discounting from the median market offer, however the minimum market offer indicated that there were competitive offers available for consumers.

The market offers in the DMO 5 period so far indicate that there has been an improvement in the discounting from the median and minimum market offer. This may be attributed to the introduction of the DMO 5 price creating a 'reset' of market offers, or the relatively stable base future prices since the government intervention. The respective DMO prices and the median and minimum market offers since May 2020 are shown in Figure 2 for the Ausgrid DMO region.

Figure 2 DMO price and median and minimum market offers – Ausgrid



Similar discounting of median and minimum market offers from the DMO prices are also noted in the other DMO regions as detailed in Appendix 3, indicating that there are consistent discounting trends in the various DMO regions.

Our Annual retail market report 2021-22, reported that Tier 1 retailers had between 87% to 90% of consumers on market offer retail contracts, whilst Tier 2 retailers had 97%, with a small annual percentage increase in the number of customers on market offers at June 2022.[4] Although there is a minority of consumers on standing offers, for those consumers, the convergence of the DMO price and the median market offer indicates that the historical DMO 4 and current DMO 5 price may be less of a 'safety net' and more of a 'typical' retail offer.

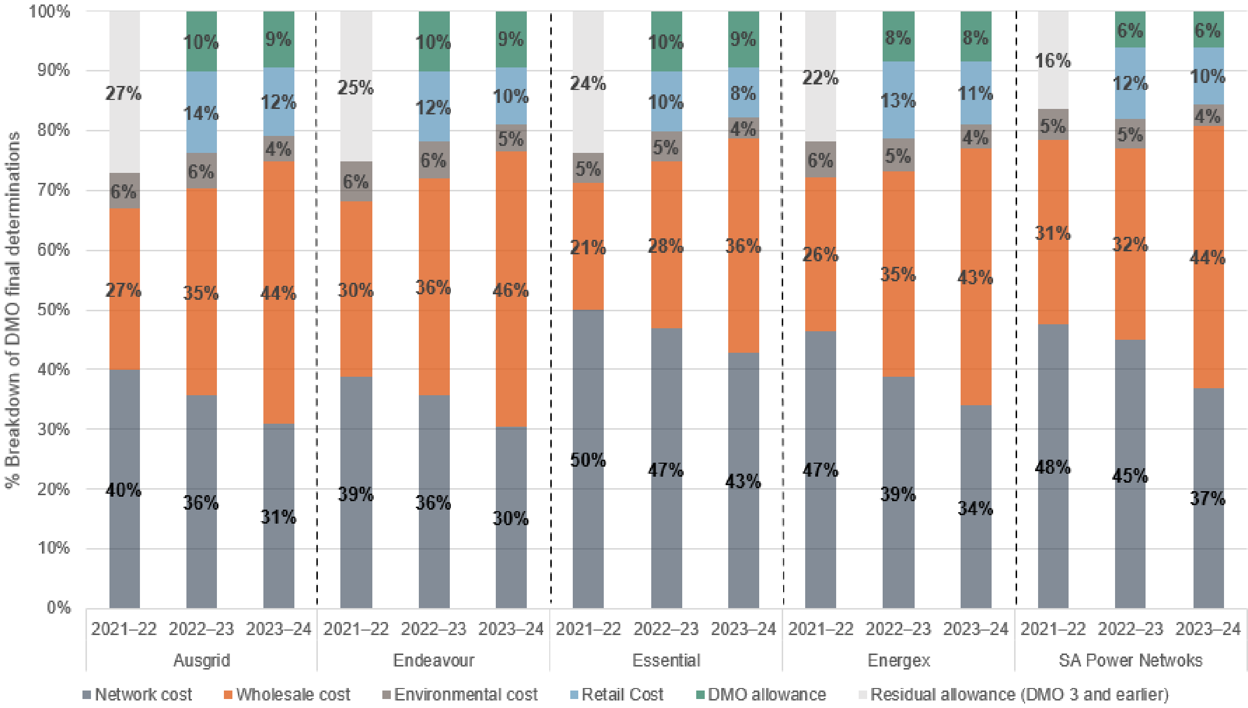
In the DMO 5 issues paper we stated that we were concerned about the impact of increasing market offers on consumers and consumer debt levels. These concerns remain for our determination of DMO 6 prices as consumers experience other cost of living pressures. This highlights the importance of the DMO in protecting consumers from unjustifiably high prices, by ensuring only reasonable costs are included in the DMO. However, as we did in our DMO 5 determination, we will continue to closely scrutinise all cost components of the DMO to ensure we understand the impacts on retailers and retail competition.

2.3 Changes in the cost stack

The composition of the DMO cost stack and consumers' bills have changed since our initial DMO determinations. Increasing wholesale costs as noted above, with reducing or stabilising network costs over recent years has resulted in wholesale costs being the highest component of a residential customers bill in 4 out of the 5 DMO regions.

4 AER, Annual retail markets report 2021-22, 30 November 2022, p. 27.

Figure 3 Breakdown of DMO 3, DMO 4 and DMO 5 final determinations for residential customers



Our 2023 Electricity network performance report explains the drivers of network costs and how the return on capital is the largest component considered.[5] As we enter into an external environment with higher interest rate and inflation expectations in the short term, there will be a significant increase in the allowed rates of return included in the upcoming regulatory determinations for distribution network service providers.

Alongside the higher rate of returns, capital expenditure on the Integrated System Plan, climate resilience, cyber security and facilitating consumer energy resources will likely drive larger regulatory asset bases for distribution and transmission network service providers. This will increase both the return on capital and return of capital components of network bills and the costs paid by consumers in future DMO decisions.

With wholesale costs possibly moderating, these higher network costs are likely to be a larger driver of future DMO outcomes.

2.4 Increased solar uptake and impacts on peakiness of load for retailers

In the past fifteen years there has been a continual increase in the number of rooftops with solar photovoltaic (PV) systems. Consumers seeking reduced energy bills, less reliance on the electricity grid and a reduced carbon footprint, has resulted in Australia having over 3.4 million installed solar PV systems.[6] With approximately 30% of Australian households having solar PV systems,[7] their continual installation has created a fundamental change in how consumers consume from the electricity grid.

5 AER, *Electricity network performance report*, Australian Energy Regulator, 7 July 2023, p. 11.

6 Department of Climate Change, Energy, the Environment and Water, Solar PV and batteries, accessed 4 October 2023.

7 Australian Renewable Energy Agency, Solar PV research and development in Australia, accessed 4 October 2023.

Solar PV systems create a 'carve out' in demand from the electricity grid during daylight hours, as consumers can use the electricity generated from their rooftop system. This carve out in demand also changes the contracting of retailers, who no longer need to purchase energy to cover the consumption of customers with solar PV systems.

Although decreasing prices during the middle of the day, the carve out creates peakier demand at the start and end of the day. This peakier demand increases the contracting costs for retailers, who need to purchase more expensive cap contracts, to replace the less expensive base contracts.

To install a solar PV system a consumer will need to replace their accumulation meter with an advanced meter. The load profiles in our DMO 5 final determination used net system load profile (NSLP) and controlled load profile (CLP) data from the Australian Energy Market Operator (AEMO), which is based on accumulation meters. Due to this, the impact of solar PV systems was not reflected in the DMO 5 load profiles.

As confirmed in our DMO 5 final determination, we have investigated incorporating advanced meter data in the load profiles in DMO 6 by creating a blended load profile using data from advanced meters, the NSLP, and the CLP. This analysis and the discussion of a possible change is explained in chapter 3.

We expect the number of solar PV systems to increase in future DMO decisions, which may lead to peakier load profiles. The rollout of advanced meters is also expected to create a more accurate view of the consumption patterns of consumers. This combination of peakier load profiles and more accurate data may lead retailers to adapt their hedging strategy e.g. to change the mixture of hedge contracts they purchase and the extent to which they are exposed to the spot price.

However, in the [2023 Electricity Statement of Opportunities], AEMO noted that greater orchestration of generation from solar PV and other consumer energy resources will improve reliability risks over the next 10 years and decrease the need for utility-scale solutions.[8] This orchestration will have a positive cost impact for retailers (and ultimately consumers) by enabling retailers and other market participants to reliably access the generation from solar PV systems and other consumer energy resources during high demand periods.

We will take all of these changing dynamics into account in the DMO methodology as the market evolves over the coming years.

2.5 Advanced metering development

As discussed in chapter 5 of this issues paper, the review into the regulatory framework for metering services by the Australian Energy Market Commission (AEMC) recommended establishing an acceleration target to reach universal deployment and uptake of advanced meters in the NEM by the end of 2030.[9]

The anticipated acceleration of advanced meter installations will increase the costs incurred by retailers and, as a result, increase the advanced meter costs included in the DMO price. Due to the AEMC's acceleration target period not commencing until July 2025 we expect DMO 6 to feature similar advanced metering costs to the costs included in DMO 5.

However, when the rollout intensifies in DMO 7 (and future DMO determinations), the advanced metering costs will certainly increase. In this issues paper we are asking stakeholders several

8 AEMO, *2023 Electricity Statement of Opportunities*, August 2023, pp. 92–95.

9 AEMC, *Final Report – Review of the regulatory framework for metering services* *Final Report – Review of the regulatory framework for metering services*, 30 August 2023, p. i.

questions on advanced meters, including the cost recovery process, the cash flow impact on retailers and what costs should be included in the DMO.

Feedback from these questions will provide us with a better understanding on advanced metering costs and will help us work with stakeholders to determine how such costs are included in DMO determinations. This will ensure that only the efficient costs of the rollout are recovered by retailers.

3 Wholesale costs

We refer to our forecasting approach for wholesale costs as 'market based'. Our wholesale cost forecast is a function of energy supply and demand forecasts, the assumed hedging strategy of a retailer to manage their exposure to the spot market, and any final exposure to the spot market.

The hedging strategy adopts the position of a hypothetical prudent retailer, which progressively purchases hedging contracts, decreasing most of its exposure to the wholesale electricity market in the lead up to each DMO period.

We use an external consultant to assist us with determining the wholesale costs in the DMO. Using demand and supply forecasts, our consultant develops wholesale energy market simulations. These simulations estimate expected spot market costs and volatility, and the hedging of the spot market price risk by entering electricity contracts. The publicly available ASX electricity contract prices and traded volumes are used to model the cost of implementing the hedging strategy in each scenario. The cost for each scenario is then distributed, where costs around the median represent those that are likely to eventuate and those at the extreme high and low ends less likely to occur. In our DMO 4 and DMO 5 decision we adopted the 75th percentile outcome as the input for DMO prices.

For DMO 6 we are seeking feedback on 2 main areas of our forecasting methodology. The first is whether and how we incorporate advanced meter data into our estimated load profiles. The second is whether, due to liquidity concerns, we should use confidential contract information to estimate the contracting costs in our wholesale methodology.

The next 2 sections of this chapter cover these issues in further detail. The third section of this chapter covers other wholesale cost issues on which we seek stakeholder feedback.

3.1 Load profile assumptions

Load profiles are a key input in estimating wholesale costs. Load profiles feed into our methodology in 2 ways:

- The system load for each region helps model the regional wholesale electricity spot price.
- In previous determinations, we have used AEMO's published NSLP and CLP to model the cost to retailers of procuring energy for residential and small business customers.

The NSLP and CLP are created using accumulation meter data only. When the DMO was conceived, accumulation meter data was the predominate meter type, with the resultant NSLP and CLP representative of the customer base. However, in recent years advanced meters have become more common. Solar PV system installations have been the main driver of metering upgrades in DMO regions. As reported in our 2023 *Electricity network performance report,* the proportion of residential customers with an advanced meter in 2022 was approximately 35% for NSW and 30% for Queensland and South Australia.[10] The proportion of small business customers with an advanced meter in 2022 was approximately 45% in NSW and 30% for Queensland and South Australia.[11] The consumption profiles of all these customers are effectively excluded under the NSLP and CLP method in previous DMOs.

The technological capabilities of solar PV systems have enabled customers with these systems to reduce their energy needs from the grid during daylight hours. During the DMO 5 consultation

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[10] AER, *2023 Electricity network performance report*, July 2023, p. 28.

[11] AER, *2023 Electricity network performance report*, Australian Energy Regulator, July 2023, p. 29.

process we received several responses from stakeholders which stated we should incorporate advanced meter data in the load profile estimations as soon as possible. The common sentiment was that AEMO's NSLP and CLP data was no longer an accurate reflection of a retailer's customer base.[12] In response to this broad sentiment we committed to investigate if we could incorporate advanced meter data into the load profile in DMO 6.

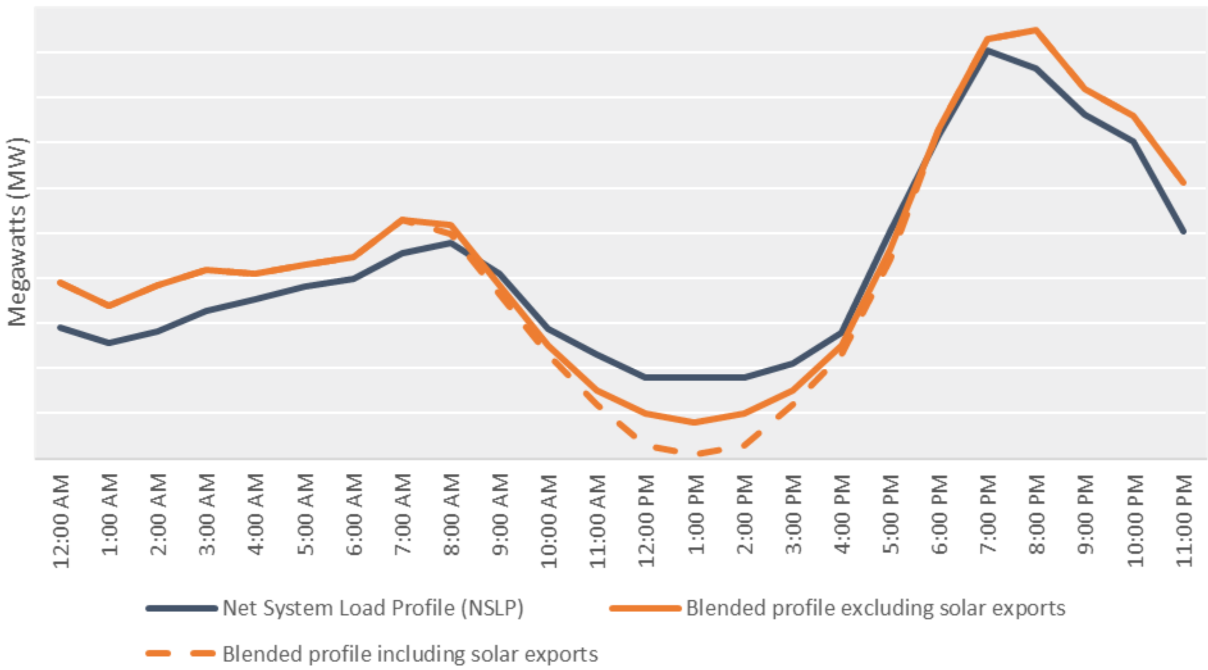
After finalising our DMO 5 determination, we asked ACIL Allen to consider how advanced meter data, given to us by AEMO, could be used to estimate load profiles blended with the NSLP and CLP. This blended load profile would combine data from the NSLP/CLP and advanced meters to create singular load profiles for the DMO regions.

An illustrated example of the blended profiles alongside the NSLP is shown in Figure 4. Although the magnitude of the impact of solar PV systems differs across the DMO regions, this example highlights how the penetration of solar PV systems has resulted in a carve out of demand during daylight hours when compared with the NSLP.

The carve out of demand in the blended profile will likely result in a higher wholesale cost component in the DMO. The peakier profile will require a change in the mixture of contracts from previous DMO determinations, which may involve retailers needing to use more expensive cap contracts at the cost of the less expensive base contracts to hedge against the peakier load. This higher reliance on cap contracts also increases the risk that retailers over-hedge to avoid the price impact of potential high-demand peak periods that don't eventuate.

In Figure 4 we have provided two indicative blended load profiles. This is due to the current advanced metering data from AEMO not being able to distinguish between an advanced meter's consumption and the exports/generation to the electricity grid.

Figure 4 Indicative load profiles – average time of day demand (MW)



[12] AGL Energy Limited, Submission to DMO 5 draft determination, 6 April 2023, p. 1; Origin Energy, Submission to DMO 5 draft determination, 6 April 2023, p. 4; Red Energy and Lumo Energy, Submission to DMO 5 draft determination, 6 April 2023, p. 3.

Due to this limitation, if a consumer exports/generates to the grid, it will decrease their load data below their actual consumption. This creates a greater carve out in the blended load profiles during daylight hours, and a peakier load profile.

We are currently working with AEMO to obtain a dataset that differentiates between the advanced meter's consumption and its generation/exports to the grid. Despite this data issue, we still believe that a blended load profile including advanced metering data would more accurately represent the load that a prudent retailer would hedge.

In this issues paper we are asking stakeholders for their views on the load profile for DMO 6. This includes whether we should change to a blended profile using data from advanced meters and accumulation meters or keep the existing NSLP and CLP approach from DMO 5.

In balancing these two approaches, we note that a change to improved accuracy in the blended model will reduce transparency for stakeholders. In contrast to the NSLP and CLP (publicly available on AEMO's website), any blended load profile used in DMO 6 will not be publicly available for stakeholders to analyse. We are asking stakeholders for their views on this trade-off between accuracy and transparency, and how we can address issues of transparency.

We are also asking for stakeholder views on whether we should develop separate load profiles for residential and small business customers. Although there are likely differences in the impact of solar PV systems between these customer types, retailers may take a combined portfolio view for residential and small business customers when determining their hedging strategy. We are interested to hear from retailers on the drivers of their hedging practices in this regard.

In our DMO 5 issues paper we asked stakeholders whether there should be a singular load profile for NSW to replace separate load profiles for the Ausgrid, Essential Energy and Endeavour Energy regions. Our consultant for DMO 5 (ACIL Allen) provided a technical report for the DMO 5 period[13] that highlighted that the CLP for Endeavour Energy had a significant increase in the evening consumption in recent years, whilst there have been minimal changes in the CLPs for Ausgrid and Essential Energy.

This may indicate significant load differences between each of the distribution zones, based on different population basis, demographics, and home ownership which may be driving differing energy consumption needs or the propensity of consumers to install solar PV systems. Due to this, we again seek stakeholder views on whether we should have a singular load profile for NSW.

Question 1: What approach should we take towards estimating load profiles? Should we retain profiles based on the NSLP and CLP, create blended profiles using the NSLP/CLP and advanced meter data, or take another approach towards estimating load profiles? Which is most reflective of a reasonable retailer's approach?

Question 2: Is the lack of transparency of AEMO's advanced meter data a major issue for stakeholders? What information could we provide stakeholders to address issues with transparency of data?

Question 3: How should we consider the impact of solar PV exports in advanced meter data when estimating load profiles?

Question 4: Should the AER determine separate load profiles for residential and small business customers? Is this reflective of a prudent retailer's approach?

13 ACIL Allen, *DMO 2023-24 Wholesale energy and environment cost estimates for DMO 5 Final Determination*, 23 May 2023, p 52.

Question 5: Should the AER have a singular profile for the entire NSW region instead of individual load profiles based on distribution zone? Is this reflective of a reasonable retailer's approach?

3.2 Use of confidential contract information

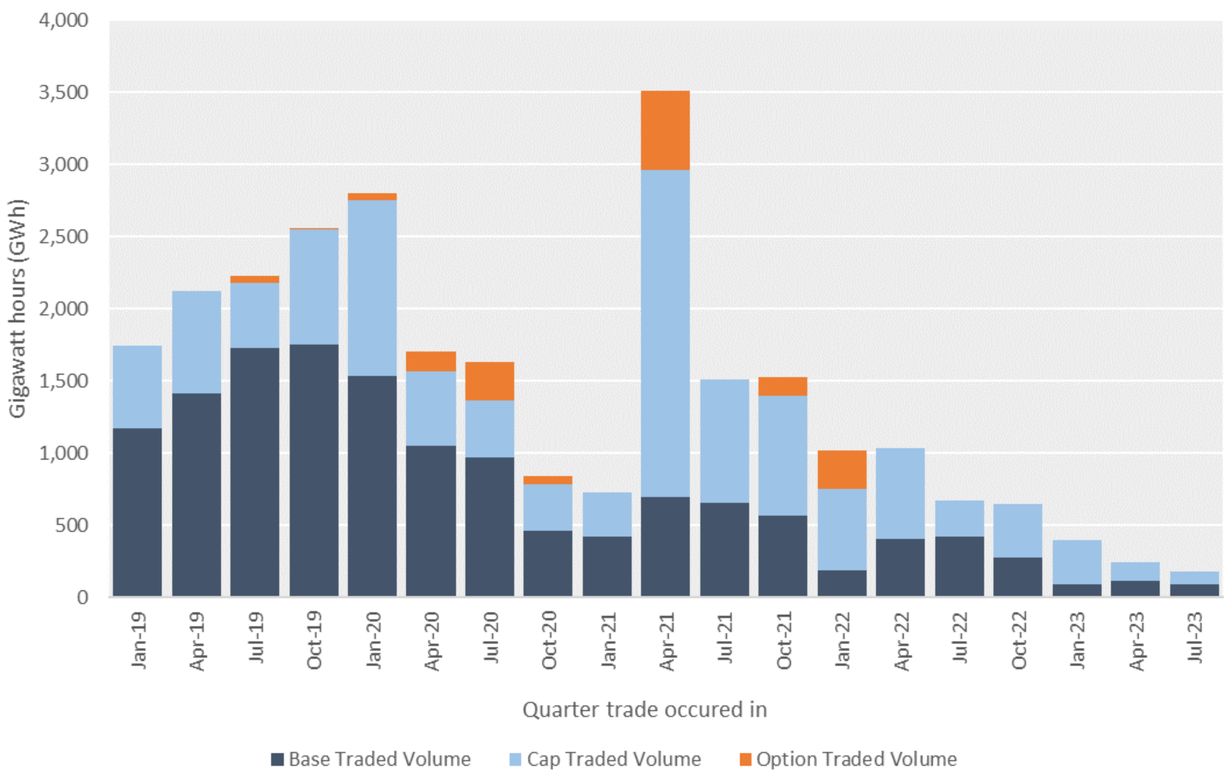
Our current wholesale methodology uses publicly available ASX trade data to price futures contracts for base, peak and cap contracts. This methodology relies heavily on a liquid contract market, where retailers can actively acquire contracts in the years leading up to the DMO period.

In making our DMO 5 determination, we noted that there were market liquidity concerns in each of the DMO regions, with these concerns most prevalent in South Australia. This created a risk that the ASX trade data was not reflective of a prudent retailer's hedging costs and that additional contract products were necessary to determine the wholesale cost component of the DMO.

To investigate this risk, throughout the DMO 5 period we collected confidential over-the-counter (OTC) contracts from retailers and generators. After analysing this information, we found that there wasn't a significant difference in the two contract markets and did not include OTC contract data in our calculations.

Since our DMO 5 determination, South Australia has continued to experience low volumes of trading – the number of contracts traded is at its lowest point in a decade. This is highlighted in Figure 5, which shows the significant decline in traded volume in the most recent quarters (noting that Q3 is still ongoing).

Figure 5 South Australia quarterly traded volume by contract type since 2019

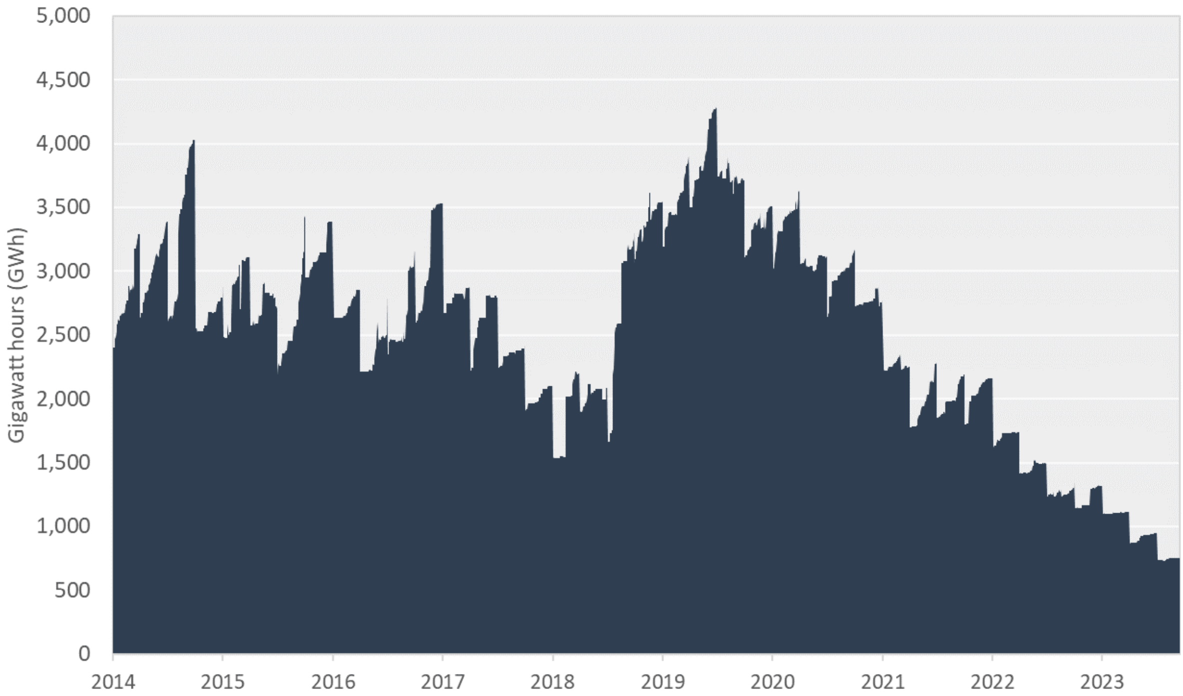


In the past few years cap contracts have become the most traded contract types in South Australia. In the other jurisdictions cap contracts are typically less than 20% of base futures traded.

Significantly for DMO 6, in South Australia, base futures contracts for the 2024–25 financial year have been scarcely traded. To date there has only been 4 MW traded for Q2 2025 for both base and cap contracts. Overall, the volume of base futures traded is currently 71% lower for the DMO 6 period than at the same time for DMO 5, with the trade in caps down as well.

Figure 6 shows open interest (a measure of how many contracts held at a point in time) in base futures for South Australia. This illustrates a continuous decline since 2019, which indicates that liquidity is worsening as new contracts are not being opened at the same rate existing contracts are closed. This may be an indication that retailers are purchasing different contract products to minimise their exposure to the South Australian spot price.

Figure 6 Open interest in South Australian base futures



For DMO 6 we hold concerns that the liquidity concerns in South Australia (and other DMO regions) have created a risk that ASX trade data is not reflective of a prudent retailer's hedging costs and that additional contract products may be necessary to determine the wholesale cost component of the DMO.

We intend to again collect OTC contract information from retailers and generators to assess whether there are any differences in the prices traded in the different contract markets.

For South Australia, we are also considering other strategies a prudent retailer could undertake to hedge against exposure to the spot price. One potential option is investigating whether a retailer could effectively hedge against the spot price in South Australia through a strategy that includes purchasing a mix of Victorian and South Australian base, peak and cap contracts and using Settlements Residue Auctions (SRAs) to access inter-regional settlements residues. Noting the liquidity concerns, we are also considering using other products a retailer can access, such as power purchase agreements in our wholesale cost methodology.

We are asking stakeholders for their views on how we can determine the wholesale cost for South Australia in the absence of contract data and what strategies we could consider when determining the hedging strategy of a prudent retailer.

Question 6: What additional data should we consider when assessing contract pricing for DMO 6, given the lack of liquidity in South Australia remains?

Question 7: In the absence of sufficient exchange traded South Australian contract data, what other methodologies could the AER investigate to determine the wholesale cost in South Australia? Would consideration of a retailer holding Victorian futures contracts with SRAs be reflective of the practice of a reasonable retailer? How would we model this?

3.3 Other wholesale cost issues

3.3.1 Changes to the coal and gas caps

Since the publication of DMO 5, there have been further announcements regarding the coal and gas caps that were in effect for the DMO 5 period. The coal cap is due to end on June 2024, and the new Gas Market Code commenced on 11 July this year, which includes a $12 per GJ price cap. We will reflect any updates to both in our modelling and continue to monitor the market impact of fuel price movements.

3.3.2 Compensation costs

For the DMO 5 final determination, we included known AEMO and AEMC compensation costs in the wholesale energy component. We intend to continue to pass these through in the DMO wholesale component as they become known.

3.3.3 Options

For the DMO 6 determination, we intend to retain our usage of exercised options in the current wholesale methodology. We consider that options provide valuable information on the cost of energy and are still an available product for retailers to use as a part of their hedging strategy. We welcome any stakeholder feedback on the way we use options and ask for evidence on any alternative ways these are used as part of prudent hedging strategies.

3.3.4 75th percentile

There are many inputs and assumptions that we consider in determining the cost of energy in the highly volatile wholesale market. This involves accounting for any uncertainty in inputs by modelling hundreds of combinations of the changing inputs and assumptions (including weather, renewable generation, and thermal generation outages). This is used to match the estimated spot market outcomes against the most efficient hedging strategy.

This creates a distribution of potential cost outcomes for a retailer in purchasing wholesale energy, where costs around the median represent those that are likely to eventuate and those at the extreme high and low ends less likely to occur. Therefore, prices above the median (50th percentile) provide a margin for error against underestimation.

In DMO 4 and 5 we used the 75th percentile of the estimated cost of wholesale energy as at this point in the distribution retailers should be able to recover their costs, while not resulting in an excessive allocation of risk towards consumers.

For the DMO 6 determination, we intend to retain our approach to taking the 75th percentile of wholesale cost estimates. We still think this strikes the right balance of risk between retailers and consumers. We welcome any stakeholder feedback on this part of the wholesale methodology and ask for evidence to move away from this position.

3.3.5 Length of book build

For the DMO 6 determination, we intend to retain the length of the book build, taking all available trades on the ASX from the first date of trade, approximately giving our book a 2 to 3-year time horizon. We believe utilising all available trades more accurately reflects the cost of energy over time that an average and prudent retailer is likely to incur. Further, a longer book build period results in wholesale costs being more stable from year to year, which helps the DMO to meet its purpose as a fallback price for consumers.

We welcome any stakeholder feedback on this part of the wholesale methodology, and if available, ask for evidence to move away from this position.

Question 8: Should we consider any other changes to the wholesale cost methodology in light of a changing wholesale market?

4 Retail costs

4.1 Our methodology

We have used a ‘cost-stack’ methodology for the past two DMO periods. This was found to be the most appropriate approach for meeting the DMO objectives and provided:

- transparency by separately determining retail costs and setting a retail allowance
- consistency in pricing between regions.

Retailers incur several costs when selling electricity. These costs include:

Costs to serve – such as costs for billing, call centres and hardship programs. We refer to the ACCC Electricity Inquiry data average costs to estimate such costs, which we escalate to the end of the DMO year using the Reserve Bank of Australia’s forecasted inflation rate.

Costs to acquire and retain customers – such as advertising campaigns and tools to inform new customers of their options, rights, and obligations. We refer to the ACCC Electricity Inquiry data average costs to estimate such costs, which we escalate to the end of the DMO year using the Reserve Bank of Australia’s forecasted inflation rate.

Advanced meter costs – retailers are responsible for managing the advanced meter installation/maintenance costs. We seek this cost information from retailers representing approximately 90% of DMO customers to set an average cost base.

Bad and doubtful debt – retailers may set aside revenue to cover instances where customers cannot repay their electricity debt. We refer to the ACCC Electricity Inquiry data as a representative sample of such costs.

Depreciation and amortisation – retailers make up-front investments (e.g. software upgrades), which depreciate over time. We did not separately determine depreciation and amortisation, but instead set a retail allowance that includes an EBITDA margin. This is the approach used by OTTER, ICRC and ESCV.

We consider that the above ‘cost-stack’ methodology remains appropriate for DMO 6, and propose to update the relevant cost calculations with the 2022–23 information from the ACCC (as well as from relevant information requests to retailers).

4.2 Bad and doubtful debt

In previous years we have calculated bad and doubtful debt costs at $26 (DMO 4) and $16.06 (DMO 5) per small customer.

Before the DMO 5 final determination we considered the weighted average of bad and doubtful debts from 3 retailers that report publicly (AGL Energy, Origin Energy and Red Energy and Lumo Energy).

Responding to stakeholder suggestions from the DMO 5 draft determination[14], we analysed ACCC Electricity Inquiry data (made up of the bad and doubtful debt of 15 retailers) to test retailers' claims and subsequently changed the approach to bad and doubtful debt cost calculations for our DMO 5 final determination. We considered that the ACCC Electricity Inquiry data would be a more representative sample than the information available from the public reports of 3 retailers.

We propose to continue this approach for DMO 6, pending availability of this data. We are engaging with the ACCC on publishing this bad and doubtful debt data in their November 2023 report.

4.3 Small business costs

Our current methodology for calculating small business costs involves converting the publicly reported variable retail costs (cents per kilowatt hour (kWh)) amount[15] so that it can be applied on a dollars per customer basis. We used the average low-voltage non-residential annual usage amount reported by distributed network service providers (DNSPs) in economic benchmarking regulatory information notices to convert the ACCC c/kWh figure into $ per customer.

In their submissions to the DMO 5 draft determination, some retailers raised concern with how the published ACCC small business retail costs were included in the DMO pricing model and recommended that improvements be considered when interpreting small business data on a dollar per customer basis. They specifically were concerned that our chosen average usage amount could be lower than the average small business usage amount reported to the ACCC. Therefore, this produces a lower value for small business costs on a per dollar basis than the ACCC data.

Given there is a wide range and non-normal distribution of usages across this group, the ACCC prefers to report such costs on a c/kWh basis. We will continue to engage with the ACCC to assess whether additional data will be available to improve the small business costs methodology.

Question 9: Do you consider these current methodologies used appropriate, and if not, what alternatives should be considered?

[14] Origin Energy, *Submission to DMO 5 draft determination*, 11 April 2023, pp. 14–15; *Momentum Energy, Submission to DMO 5 draft determination*, 5 April 2023, p. 4; Alinta Energy, *Submission to DMO 5 draft determination*, 6 April 2023, p. 3.

[15] Published in ACCC, *Inquiry into the National Electricity Market,* November 2022 report a fixed charge (dollars per customer).

5 Metering costs

Our DMO 5 final determination noted that advanced metering costs need to be included in the DMO price to ensure the outturn price was reflective of the DMO objectives – most noticeably the allowance for retailers to recover the efficient costs of providing their services.

The DMO 5 final determination included a range of between $15.12 and $24.28 (in residential) and $3.87 and $16.29 (in small business) of advanced metering costs in the DMO price, which reflected the reasonable costs of providing the advanced metering services.

The costs were determined based on information provided by retailers in September 2022 on the number of advanced meter installations in the DMO regions and the costs they incurred for the previous DMO period.

5.1 AEMC's acceleration target

Since December 2020 the AEMC had been undertaking a review into the regulatory framework for metering services. The AEMC's final report[16] made several recommendations, which most noticeably included establishing an acceleration target of reaching universal deployment and uptake of advanced meters in the NEM by the end of 2030. A rule change process will need to take place to give effect to these recommendations.

To achieve this target, the AEMC proposed that distribution networks commence planning to replace its fleet of legacy accumulation meters by 2030. Under that retirement plan framework, each distribution network would be required to develop a 5-year schedule (with yearly interim targets) to dispose of accumulation meters.

There is no legal obligation placed on retailers to meet the requirements of the AEMC's final report into the regulatory framework for metering service until DMO 7 (commencing 1 July 2025) or the implementation of changes in the National Energy Rules (NER).

The accelerated rollout of advanced meters will result in retailers installing more advanced meters. Advanced meters will enable consumers to access new service options and choose from different access and pricing services that meet their needs and preferences. The costs incurred from these installations will be included in future DMO determinations until the universal deployment and uptake of advanced meters is completed.

5.2 Metering costs for DMO 6 and future DMO determinations

For DMO 5 we requested information from retailers on the number of advanced meter installations in the DMO regions and the costs they incurred, to enable the DMO price to include the average total up-front advanced meter costs incurred by retailers for installing advanced meters for both residential and small business customers.

For DMO 6 and future DMO determinations, we seek stakeholder feedback on the best approach for including advanced metering costs in the DMO price, to prevent price spikes for consumers and enable retailers to recover their efficient advanced metering costs. The AEMC's final report recommended implementing safeguards to limit retailers' ability to levy up-front charges to customers. We would be interested to hear how retailers plan to progressively recover advanced metering costs from consumers.

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[16] AEMC, *Final Report – Review of the regulatory framework for metering services* [Final Report – Review of the regulatory framework for metering services](), 30 August 2023.

We also seek feedback on:

- whether we should determine the advanced meter costs based on historical costs incurred, or whether we should project costs based on expected installations during the DMO period. Our preference is to use historical costs incurred by retailers; however, we are interested to hear stakeholder thoughts.
- the cash flow impacts on retailers of the timing differences between incurring costs for advanced metering and the recovery of costs from consumers – including how the cost recovery differs with small retailers, who have comparatively smaller scales of operations and cash flows to manage the impact of advanced metering costs
- what direct and indirect (i.e. overheads and administrative) costs should be included in the calculation of advanced metering costs and whether costs provided by retailers should be subject to independent assurance requirements.

This feedback will assist us in determining the advanced metering costs in DMO 6, and also enable forward planning on how advanced metering costs are included in future DMO decisions when the rollout accelerates.

Question 10: Is the method for cost recovery of advanced metering costs appropriate for DMO 6 and/or future DMO decisions? If not, what alternative methods should the AER investigate to recover the cost of advanced meters?

Question 11: Should the AER project advanced meter installations instead of using historic data in future DMO decisions?

Question 12: What operational or cash flow considerations should the AER consider in determining the cost recovery of advanced metering costs? How do these considerations differ between large and small retailers?

Question 13: What operational and capital expenditure advanced metering costs should the AER include in the costs recovered by retailers? Should these costs be subject to independent audit or review?

6 Retail allowance

The retail allowance covers retailer profit margin and an allowance to meet the DMO objective to allow retailers to recover their efficient costs of providing services.

6.1 DMO has additional objectives to incentivise retail competition and consumer engagement

The Regulations make clear that the DMO is intended to be a reasonable price, not the lowest or most efficient price. In keeping with the overarching policy objectives for the DMO, the retail allowance must also be set to incentivise:

- retailers to invest, innovate and compete in the market
- customers to engage in the market.

Therefore, the level of the allowance needs to reflect a return on retailer risk, allow for differences in retailers' costs and provide room for competition. We also consider it important that DMO prices include a similar level of allowance regardless of DMO region.

We acknowledge some stakeholders consistent position in previous DMO determinations that the DMO prices should include only an efficient margin. However, it is our view that the DMO regulations and objectives make the DMO different from other regulated prices. In areas such as regional Queensland, the ACT and Tasmania, where there is limited retail electricity competition, the regulated prices are intended to be efficient prices with limited competitive tension between retailers. The DMO allowance methodology also differs from the ESCV's VDO retail operating margin which represents the operating profit margin required to compensate investors for the capital they provide retailers.[17]

For DMO 6 we are seeking stakeholders' views on what amount in addition to the margins discussed above would be appropriate to meet the additional DMO objectives.

We are also considering whether the current approach of calculating the DMO allowance as a percentage of costs remains suitable or if another methodology is more appropriate.

6.2 Retail allowance in previous DMO decisions

Our approach to determining the appropriate allowance for the DMO objectives has changed across DMO decisions. For context this section discusses these approaches across DMO 1 to DMO 5.

6.2.1 DMO 1 to DMO 3

Our first three DMO decisions did not specify a retail allowance. Instead:

- In DMO 1 we set the DMO price in each region at the mid-point between the median standing offer and median market offer in October 2018.
- In DMO 2 the retail allowance was included in the calculated residual component, which represented a retail allowance and the retailer's operating costs. The residual component was calculated by subtracting the network, wholesale and environmental costs from the DMO 1 price and adjusting the residual for forecast CPI for the DMO 2 period.
- DMO 3 maintained the residual component by adjusting the DMO 2 residual component for forecast CPI in the DMO 3 period. This meant that DMO 2 and 3 preserved the residual in

[17] ESCV, *Victorian Default Offer 2023–24 – Final Decision Paper*, 25 May 2023, p 48.

DMO 1 and continued to reflect the standing and market offer pricing structures observed in October 2018.

6.2.2 DMO 4

After a holistic review of the DMO methodology, in DMO 4 we decided to separately determine retail costs and a retail allowance in our DMO determination. In setting the retail allowance we decided that:

- A consistent retail allowance across the DMO regions would be desirable because the DMO objectives are the same for each region and so consistency would provide a better balance of the DMO objectives and more equitable outcomes.
- The retail allowance should be calculated as a percentage of the DMO price to be consistent with the approaches adopted by other economic regulators (ICRC, OTTER, ESCV).
- It should reflect the market-wide aggregate retail allowance available in previous DMOs of 10% for residential customers and 15% for small business customers. This is another way in which it reflected the pricing structures in place prior to DMO 1.
- An immediate change to 10 and 15% retail allowances in DMO 4 would introduce significant step changes in DMO prices in regions with lower or higher implicit retail allowances. Therefore, we introduced a glidepath with gradual increases and reductions to the 10 and 15% retail allowances across DMO 4, 5 and 6.

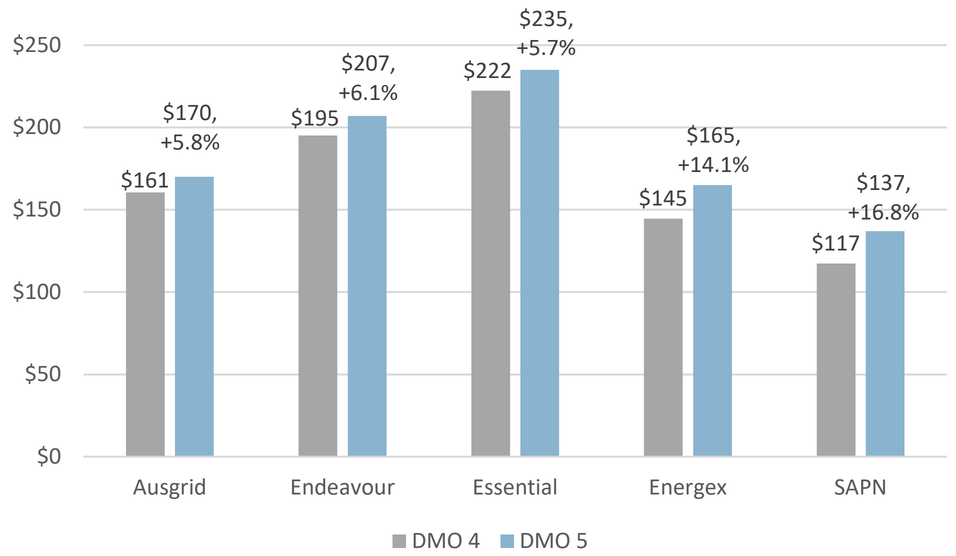
6.2.3 DMO 5

In our DMO 5 determination, we questioned whether the significant increases in the wholesale costs required a change to our retail allowance methodology of calculating the retail allowance as a percentage of the DMO price. This led to our decision to:

- reduce the NSW residential retail allowance from 10% to 9.3% to ensure that NSW residential customers were not paying materially more in dollar terms than customers in other DMO regions
- maintain the south-east Queensland and South Australian residential retail allowances at the DMO 4 values of 8.4% and 6% respectively.

The impact of the increasing wholesale costs on the retail allowance for residential customers in the DMO 5 final determination is provided in Figure 7.

Figure 7 Residential retail allowance, $ per customer, 2023 dollars



We consider DMO 6 is an appropriate time to consider whether the approach to setting the retail allowance should move away from these past approaches. Due to this, we are open to considering any necessary changes to our retail allowance methodology and are asking stakeholders if changes are necessary for the retail allowance to continue to meet, and to appropriately balance, the DMO objectives.

6.3 Quantifying the retail allowance for DMO 6

Our DMO 6 determination will determine a retail allowance that best meets the DMO objectives. This requires a retail allowance which enables retailers to innovate and invest whilst achieving a reasonable profit. The allowances also need to enable competition, encourage consumers to engage in the market and protect consumers from unreasonably high prices.

There is an inherent tension between these objectives – a higher retail allowance in the DMO price further incentivises competition and consumer engagement in the market but reduces the pricing protections in the DMO. A lower retail allowance in the DMO price further protects consumers from unreasonably high prices, but eventually reaches a point where retailers cannot compete. Our role is to determine a retail allowance that appropriately balances these competing objectives.

6.3.1 Efficient and reasonable margins

The retail allowance must be set such that it allows a prudent retailer faced with the typical costs of supplying electricity to customers to achieve a reasonable profit.[18]

In determining a reasonable profit, we consider decisions of other economic regulators, as well as the actual retail margins in competitive markets observed by the ACCC as part of its electricity market inquiry.

Other economic regulators have determined that margins ranging from 5% (OTTER)[19] to 5.3% (ESCV and ICRC)[20] of total price are appropriate for regulated electricity prices. The Queensland Competition Authority is estimated to have included a 3.9% margin in its most recent price decision for regional Queensland.[21]

As part of its electricity market inquiry functions, the ACCC produces a yearly report examining the costs and margins of electricity retailers in the NEM. These reports are based on the actual cost and revenue information provided by 15 electricity retailers selling to 86% of residential customers and 79% of small business customers in the NEM.[22] The ACCC has found these retailers' NEM-wide margins for residential customers have gradually declined from a peak of 8.9% in 2016–17 to 2.5% of total costs in 2021–22.[23]

6.3.2 Allowing different retailers to compete and encourage customers to engage in the market

Retailers face varying costs to serve and acquire and retain customers. Larger retailers may have achieved economies of scale, allowing fixed costs to be spread over a broader customer base and

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18 S16(4)(b) of the regulations.

19 OTTER, Pricing Proposal for Period 2 of the 2022 Standing Offer Price Determination 1 July 2023 – 30 June 2024, Office of the Tasmanian Economic Regulator, p. 8.

20 Essential Services Commission, *Victorian Default Offer, Final Decision Paper 2023–24*, 25 May 2023, p. 47; Independent Competition and Regulatory Commission, *Final Report Electricity Price Investigation 2020–24*, p. 65.

21 Essential Services Commission analysis of Queensland Competition Authority 22–23 determination, *Victorian Default Offer, Final Decision Paper 2023–24*, 25 May 2023, p. 49.

22 ACCC, *Inquiry into the National Electricity Market,* November 2022 report , Appendix B.

23 ACCC, *Inquiry into the National Electricity Market,* November 2022 report , Appendix D, D10.2, AER analysis expressing EBITDA margin as percentage of total cost stack.

reducing their costs on a per customer basis, whereas newer entrants may not enjoy this same benefit.

The ACCC has observed that smaller retailers tend to have higher per customer costs to serve and acquire and retain customers than the 'Tier 1' retailers (AGL, EnergyAustralia and Origin Energy). In its most recent report, the ACCC observed that the average per customer costs to serve are $48 higher than for non-Tier 1 retailers, while costs to acquire and retain are $27 higher for non-Tier 1 retailers.[24]

In September 2023, AER internal analysis indicated that around 93% of market offers are priced at or below the DMO, with discounts of up to 18% to 28% off the DMO price depending on region.[25] This is evidence that the retail allowance in DMO 5 allowed retailers to continue to compete and offer discounts off the DMO price, incentivising customers to shop around and switch from a standing offer (which is capped by the DMO price).

This indicates that retailers may have recovered from the high wholesale prices and volatility that occurred in the final quarter of 2022, which saw a reduction to around 75% of market offers being priced at or below the DMO 4 price, and discounts of up to 14% to 25% off the DMO 4 price.[26]

To meet the DMO objectives, the DMO price and retail allowance should be set such that it allows a diversity of retailers with varying costs to serve and acquire and retain customers to enter, remain and compete in the market. We consider it is in the long-term interests of customers that the retail market remains competitive with many retailers offering a diverse range of market offers.

However, we note some consumer groups have previously argued that the retail allowance should not accommodate for differing retailer costs if the retail costs component also includes costs to acquire and retain customers.[27]

6.3.3 Protecting customers from unreasonably high prices

The DMO must also protect customers that have not engaged in the market from unreasonably high prices. This objective differs from the other objectives as it places an upper bound on the retail allowance above which DMO prices become unreasonably high.

In DMO 5 we considered whether a retail allowance percentage remained appropriate as it would compound the impact of large increases in the wholesale cost component. In balancing the DMO objectives, we decided to reduce the residential retail allowance percentage in NSW from 10% to 9.3% and hold the south-east Queensland and South Australian residential retail allowances at the DMO 4 values of 8.4% and 6%, respectively.

6.4 Possible changes to consider for DMO 6

There are several different options for a potential retail allowance, which may include:

- Maintaining the current approach of calculating the retail allowance as a percentage of the DMO price.
- Setting the retail allowance as a fixed dollar amount.

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24 ACCC, *Inquiry into the National Electricity Market,* November 2022 report, Supp Table D14.7a, 14.10a.

25 AER analysis of Energy Made Easy market offer data on 13 September 2023.

26 AER analysis of generally available market offers on 30 September 2022.

27 Energy Consumers Australia, *Submission to DMO 4 draft determination*, 17 March 2022, p. 1; Public Interest Advocacy Centre, *Submission to DMO 4 draft determination*, 17 March 2022, p. 1.

- Separating the retail allowance into a percentage-based efficient margin component and a fixed competition allowance component.

The efficient margin could be calculated in a similar way to the approaches used by OTTER, ICRC and ESCV in their regulatory decisions. The additional competition allowance could be determined according to retail cost data provided by large and small retailers to the ACCC or some other data source.

The potential options provided above are not an exhaustive list. We are interested in feedback from stakeholders on whether there are other retail allowance options we should consider for our DMO 6 determination, which would better meet the DMO objectives.

We also welcome stakeholder feedback on what specific data we should use to determine the retail allowance and what potential components are missing from the retail allowance.

Question 14: Are there methodological changes that would allow us to better balance the objectives in the retail allowance?

Question 15: Should the retail allowance be a fixed dollar amount, and if so, why?

Question 16: Alternatively, should the retail allowance be cast as separate components of efficient margin (percentage based) and additional competition allowance? How would these be calculated?

Question 17: What components are missing from the retail allowance and why?

6.4.1 Differences in residential and small business retail allowance

Analysis of underlying retailer costs in the DMO 4 position paper and draft determination found that the implicit retail allowance present in DMO 1 and DMO 3 were on aggregate approximately 10% and 15% of DMO prices for residential and small business customers, respectively. We considered that higher retail allowance for small business customers met the DMO objectives because it reflected the different market characteristics of this customer type. This was based on ACCC analysis that NEM-wide retail margins for small businesses were 0.5c/kWh or 60% higher than for residential customers,[28] and our consideration of the different risks for small business customers e.g. the higher level of average customer debt to their retailers.

However, this is a different approach to the decisions of other economic regulators that apply a consistent margin across both residential and small business consumers, and we are open to reconsidering it.

Question 18: Should the retail allowance differ for residential and small business consumers? If so, what risk or cost factors drive this difference and how should this be calculated?

[28] ACCC, *Inquiry into the National Electricity Market*, November 2021 report, November 2021, p. 18.

7 Other DMO costs and considerations

This chapter discusses the approaches for determining other DMO factors such as environmental costs, network costs, NSW Renewable Energy Zone (NSW REZ) costs, NSW DNSPs' revenue resets, as well as annual usage and timing and pattern of supply.

We consider that the methodologies and assumptions we used for many of these other factors in the DMO 5 final determination remain appropriate for DMO 6; however, we welcome any feedback or additional information from stakeholders on these factors.

7.1 Environmental costs

Environmental schemes applied by the Australian Government and state and territory 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 scheme and jurisdictional green schemes.

Many environmental costs relate to complying with the renewable energy target. 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.

Other environmental costs relate to costs incurred from passing through jurisdictional schemes. These schemes involve incentives to assist consumers to reduce their energy consumption and to drive the uptake of solar PV generation.

We decided in the DMO 5 final determination to continue to retain our market-based approach[29] to environmental cost estimations with updates for new and amended schemes.

We consider this approach remains reasonable, noting that most stakeholder submissions on our DMO 5 draft determination did not discuss or raise any issues with the approach we had proposed for DMO 5 on environmental cost estimations.

7.2 Network costs

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

We decided in the DMO 5 final determination to continue basing DMO network costs on flat rate tariffs prices to calculate the DMO network component in each distribution region.[30]

We consider this approach remains appropriate and that the process to alter our approach would add complexity and reduce transparency, without providing major benefits to stakeholders.

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[29] AER, *Final determination, DMO prices 2023-24*, p. 28, section 6.4.

[30] AER, *Final determination, DMO prices 2023-24*, p. 13, section 4.3.

However, we would like to hear from stakeholders on whether this approach will remain appropriate for DMO 6 and future determinations, given there are a growing number of customers with underlying time of use network tariffs. It may be appropriate to revisit the merits of a blended network cost component that reflects the costs of both flat rate and time of use based network tariffs.

Question 19: Should network costs be based on a blend of flat rate and time of use network tariffs? If so, how should this blend be calculated?

7.2.1 NSW REZ costs

NSW has introduced a new framework to develop REZ as part of its energy transition plan, for which the AER is responsible for regulating costs. We made our first cost contribution determination on 24 February 2023, setting out the costs that would be recovered from NSW electricity consumers in 2023–24.[31] These costs cover:

- cost for payments to network operators
- costs associated with successful tenders for infrastructure underwriting contracts (known as long-term energy service agreements)
- the administrative costs of scheme entities.

An estimate of NSW REZ costs (on a $ per year basis) was included in the DMO 5 draft determination for residential and small business customers. We developed this estimate by:

- using a $/MWh cost by dividing each DNSP's NSW REZ costs to be recovered by the DNSP's forecast energy (GWh per year)
- converting the $/MWh cost to an annual $ cost by multiplying the $/MWh by the respective NSW DNSP's DMO usage amounts for residential and small business customers.

We consider this approach will remain reasonable for the DMO 6 draft determination. We anticipate that the DMO 6 final determination will not require this separate calculation of NSW REZ costs because DNSPs will recover these costs through their network tariffs, which will be included in the network cost component of the DMO 6 price.

7.2.2 NSW DNSP revenue resets

Network revenues are smoothed across a 5-year regulatory period to reduce fluctuations in between years and allow for relatively predictable price movements. Larger changes can occur through a revenue determination, which sets the revenues for the next 5-year regulatory period. The 2024–25 year will be the first year of the 2024–29 regulatory period. NSW electricity DNSPs are required to submit their network tariffs by 21 May 2024, following the AER's distribution determinations by the end of April. The NSW network tariffs will generally be approved by the AER in mid to late June.

Given the AER's revenue determinations for the NSW DNSPs are due by end of April 2024, the final revenue numbers will not be available in time for the DMO 6 draft determination. The AER will engage with the various DNSPs to identify what information is available and how changes could impact costs for the NSW DNSPs. This will enable an accurate estimate of approved network

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31 Under Part 7 of the *Electricity Infrastructure Investment Act 2020 (NSW)* (*"EII Act"*) the AER, as the regulator, gazetted the NSW REZ cost contribution on 28 February 2023.

tariffs for the draft determination and minimise changes in network cost component from the draft to final determination.

DMO 2 was the last time that distribution determinations were still forthcoming at the time we were making the DMO determination. For the DMO 2 determination we considered the best available forecasting approach was to calculate the change in annual revenue to estimate changes in distribution network, transmission network and alternative controlled service costs.[32] These forecast changes were then applied to the relevant network tariffs from the last approved annual pricing proposal.

The AER has since conducted work to improve and streamline the processes for assessing network tariffs in years 2 to 5 of the regulatory period, with the goal of bringing forward final network charges with a particular focus on DMO regions. The AER will be looking at how these can be implemented to improve the timelines of pricing proposals and approvals in the first year of the regulatory period. At this stage we consider it likely that we will have approved, or at least received the DNSP’s proposed network tariffs in time for the DMO final determination.

7.3 Annual usage and time of use (TOU) pattern

Under Part 3 of the Regulations, we are required to determine ‘broadly representative’ annual supply amounts for residential and small business customers in each distribution region, from which a DMO price and reference price can be calculated. In this document we refer to annual supply as annual usage.

We must also determine the timing and pattern of supply to residential customers. The Regulations refer to these elements in combination as the ‘model annual usage’.

7.3.1 Annual usage

In our DMO 5 final determination we decided to retain the same usage amounts for residential customers for general usage and controlled usage, and small business customers, as in previous determinations. However, we added one day’s consumption to annual usage from DMO 4 due to a leap year in 2023–24.

To provide consistency and continuity for stakeholders, we propose to use these settings for the DMO 6 determination (365 days) and review annual usage as part of the next DMO methodology for the 2025–26 (DMO 7) process.

The ACCC released its June 2023 electricity report, which includes the most recent findings on residential and small business usage. We consider that our DMO 5 assumed annual usage amounts remain broadly representative of their respective customer groups.

When compared with the ACCC observations that represent residential customers[33] with and without controlled load, we note that the corresponding residential annual usage amounts assumed in previous DMO determinations:

- sit comfortably within the interquartile range
- are approximate to the medians observed by the ACCC
- customers without controlled load are around 3% to 25% below the ACCC observed median

32 Referred to as X-factors in the AER network revenue determinations.

33 ACCC, *Inquiry into the National Electricity Market*, June 2023 report, Appendix E Table A3.2.

customers with controlled load are around 25% to 46% above the ACCC median.

The ACCC has continued to observe a much wider range of annual usage for small business customers,[34] reflecting the variety of small businesses and the different ways they use electricity to produce goods and services. The 10,000 kWh small business usage amount assumed in the DMO sits above the median but within the interquartile range.

Noting that such a wide range in usage amounts among small businesses makes it difficult for any single figure to accurately represent all small businesses, we consider the 10,000 kWh usage (which is situated within the interquartile range) to be a broadly representative usage amount.

7.3.2 Time of use pattern

In our DMO 5 final determination we decided to update the timing and pattern of supply usage profiles using new AEMO advanced meter data but retain our key assumptions from previous determinations. That is:

- assume the same usage occurs every day (with no variation for weekday, weekend or season), as in previous determinations
- use the same proportional allocations of annual controlled load usage across multiple controlled loads
- retain a single 24-hour usage profile
- update these using the AEMO advanced meter data for each region, averaged over 3 years
- specify usage at 30-minute intervals.

We consider this approach remains reasonable. The DMO regulations require us to determine a time of use pattern in each region that is broadly representative of all customers.

We note that an approach introducing greater detail (for example, separate time of use patterns for different seasons and/or weekdays and weekends) could introduce greater accuracy as it would reflect changes in consumption patterns across the year. However, we also consider that any time of use pattern aiming to represent all customers is unlikely to capture many possible drivers in individual usage patterns such as climate or individual household characteristics. Given this, we consider altering our approach would add complexity and reduce transparency without providing major benefits to stakeholders.

Question 20: Does our proposed approach to determining a broadly representative time of use pattern remain appropriate?

[34] ACCC, *Inquiry into the National Electricity Market*, June 2023 report, Appendix E Table A9.2.

Appendix 1 – Background and context of the DMO

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 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, South Australia, Tasmania, the ACT and Queensland.

Our objectives include:

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

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

Policy context

In the final report of its 2018 Retail Electricity Pricing Inquiry, the ACCC noted electricity standing offer prices were unjustifiably high.[35]

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.

The Australian 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.[36]

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35 ACCC, *Retail Electricity Pricing Inquiry*, Final report, Australian Competition and Consumer Commission, 2018.

36 Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019.

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.[37] 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 the efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention
- enable competition, innovation and investment by retailers, and retain incentives for consumers to engage in the market.

Customers on standing offers

Most customers on standing offers in DMO regions are served by Tier 1 retailers. The Tier 1 retailers in the DMO regions are also the designated 'local area retailers' under the NERL.[38]

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

- have not taken up a market offer since the introduction of retail competition in that jurisdiction
- are supplied under a retailer's 'obligation to supply' (for example, if a poor credit history means other retailers will not supply them)[39]
- have moved into a premises and receive supply from the existing retailer supplying the premises but are yet to contact the retailer[40]
- have defaulted to a standing offer following the expiry of a market contract.[41]

All retailers must have, and must publish on their websites, a standard retail contract and standing offer prices.[42] A customer will always have a particular retailer (called the designated retailer) that will be required to advise the customer of the availability of the standing offer[43] and offer that customer the standing offer prices under its standard retail contract.[44] The retailer that has this obligation will depend on the circumstances.[45]

Table 1 sets out the number and proportions of customers on standing offers for DMO areas in Q4 2022–23.

Table 1 Standing offer customers in DMO areas

Area	Residential customers (No. and %)	Small business customers (No. and %)
NSW	284,169 (8.4%)	46,447 (15.2%)

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[37] ACCC, *AER Default market Offer, Submissions to the Draft Determination*, Australian Competition and Consumer Commission, 20 March 2019, pp.1–2.

[38] National Energy Retail Law, s 11.

[39] Unlike other retailers, under s. 22 of the National Energy Retail Law, local area retailers cannot refuse to supply customers.

[40] AEMC, *Advice to Council of Australian Governments Energy Council: Customer and competition impacts of a default offer*, 20 December 2018, p. 15.

[41] 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.

[42] National Energy Retail Law, ss. 23, 25.

[43] National Energy Retail Law, s. 22.

[44] National Energy Retail Law, s. 22.

[45] AER, 2020 Compliance check, Obligation to make an offer to a small customer, Australian Energy Regulator.

South-east Queensland	141,599 (9.4%)	19,880 (18.1%)
South Australia	60,952 (7.5%)	13,696 (15.8%)
Total standing offer customers	486,720 (8.5%)	80,023 (15.9%)

Note: Customer numbers for south-east Queensland have been extrapolated from all of Queensland by excluding Ergon Energy retail customers. Other retailers have customers numbers in regional Queensland, so customer numbers are approximate.
Source: AER, Retail market performance update, Quarter 4 2022–23.

DMO regulatory framework

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

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

- how much electricity a broadly representative small customer of a particular type in a particular distribution region would consume in a year and the pattern of that consumption[46] (the model annual usage)[47]
- 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).[48]

The DMO price applies to residential and small business customers on standing offers in distribution regions that are not subject to retail price regulation.[49] These regions are:

- NSW – Ausgrid, Essential Energy and Endeavour Energy
- South Australia – South Australian Power Networks
- 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 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:

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

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

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

49 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.

- 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 that a retailer should be able to make a profit, and other matters we consider relevant.[50] Our previous determinations have set out how we have considered these factors in setting the DMO price.[51]

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[52]
- small customers must be told how a retailer's prices compare with the AER determined annual price[53]
- 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.[54]

As the Code has been made under the *Competition and Consumer Act 2010*, enforcement and compliance with these provisions is the responsibility of the ACCC.

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

[51] AER, *Final determination, DMO prices 2019–20*, pp. 27–29; AER, *Final determination, DMO prices 2020–21*, pp. 75–77.

[52] Regulations s. 10.

[53] Regulations s. 12.

[54] Regulations s. 14.

Appendix 2 – List of stakeholder questions

Wholesale costs	
Question 1	What approach should we take towards estimating load profiles? Should we retain profiles based on the NSLP and CLP, create blended profiles using the NSLP/CLP and advanced meter data, or take another approach towards estimating load profiles? Which is most reflective of a reasonable retailer's approach?
Question 2	Is the lack of transparency of AEMO's advanced meter data a major issue for stakeholders? What information could we provide stakeholders to address issues with transparency of data?
Question 3	How should we consider the impact of solar PV exports in advanced meter data when estimating load profiles?
Question 4	Should the AER determine separate load profiles for residential and small business customers? Is this reflective of a prudent retailer's approach?
Question 5	Should the AER have a singular profile for the entire NSW region instead of individual load profiles based on distribution zone? Is this reflective of a reasonable retailer's approach?
Question 6	What additional data should we consider when assessing contract pricing for DMO 6, given the lack of liquidity in South Australia remains?
Question 7	In the absence of sufficient exchange traded South Australian contract data, what other methodologies could the AER investigate to determine the wholesale cost in South Australia? Would consideration of a retailer holding Victorian futures contracts with SRAs be reflective of the practice of a reasonable retailer? How would we model this?
Question 8	Should we consider any other changes to the wholesale cost methodology in light of a changing wholesale market?
Retail costs	
Question 9	Do you consider these current methodologies used appropriate, and if not, what alternatives should be considered?
Advanced meters	
Question 10	Is the method for cost recovery of advanced metering costs appropriate for DMO 6 and/or future DMO decisions? If not, what alternative methods should the AER investigate to recover the cost of advanced meters?
Question 11	Should the AER project advanced meter installations instead of using historic data in future DMO decisions?
Question 12	What operational or cash flow considerations should the AER consider in determining the cost recovery of advanced metering costs? How do these considerations differ between large and small retailers?
Question 13	What operational and capital expenditure advanced metering costs should the AER include in the costs recovered by retailers? Should these costs be subject to independent audit or review?

Retail allowance	
Question 14	Are there methodological changes that would allow us to better balance the objectives in the retail allowance?
Question 15	Should the retail allowance be a fixed dollar amount, and if so, why?
Question 16	Alternatively, should the retail allowance be cast as separate components of efficient margin (percentage based) and additional competition allowance? How would these be calculated?
Question 17	What components are missing from the retail allowance and why?
Question 18	Should the retail allowance differ for residential and small business customers? If so, what risk or cost factors drive this difference and how should this be calculated?
Other DMO costs and considerations	
Question 19	Should network costs be based on a blend of flat rate and time of use network tariffs? If so, how should this blend be calculated?
Question 20	Does our proposed approach to determining a broadly representative time of use pattern remain appropriate?

Appendix 3 – Historic market offer analysis

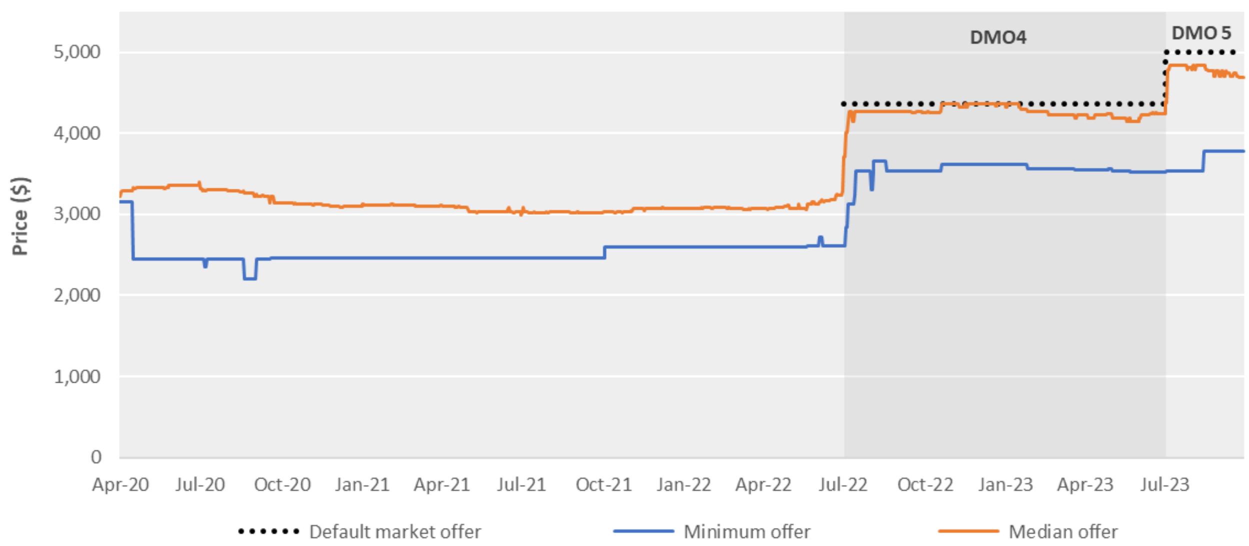
In Figure 2 we have provided the residential DMO price, and the median and minimum market offers from May 2022 for the Ausgrid region. Below we have provided the DMO price, and the median and minimum market offers from May 2022 for the other DMO regions, as well as the small business customer type. As noted in section 2.2, although the specific discounts from the DMO price from median and minimum market offers differ amongst the DMO regions, there is a consistent trend across the DMO regions.

The small business analysis below is based on DMO 4 and 5 assumed annual usage of 10,000 kWh. DMO 1, 2 and 3 small business DMO prices were based on 20,000 kWh and have been excluded from these charts.

Ausgrid

Figure 8 DMO price and median and minimum market offers – Residential

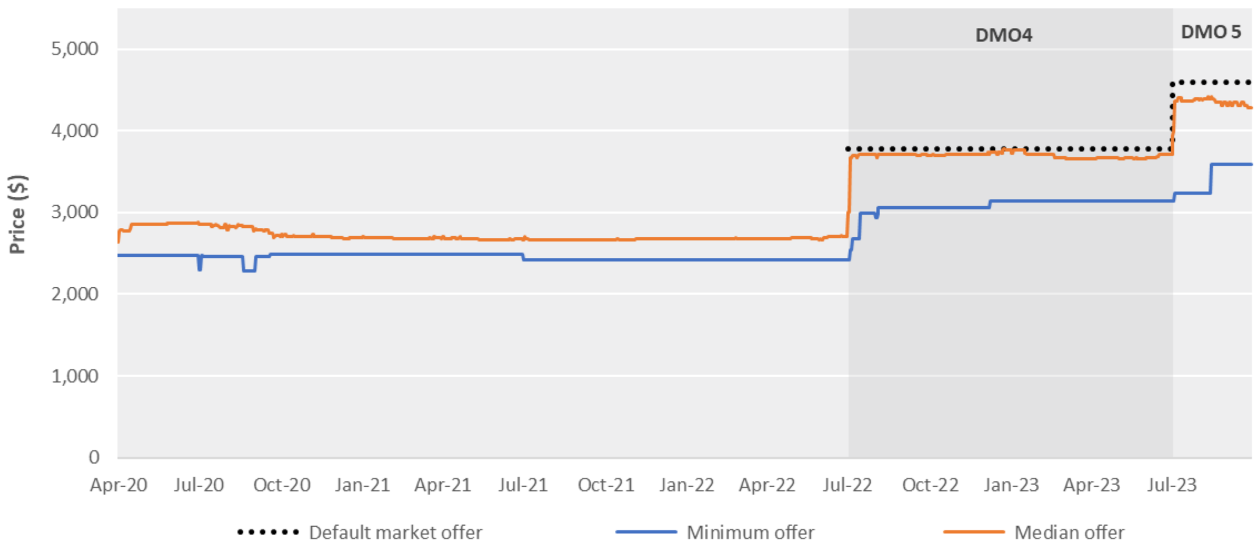
Figure 9 DMO price and median and minimum market offers – Small Business



Endeavour Energy

Figure 10 DMO price and median and minimum market offers – Residential

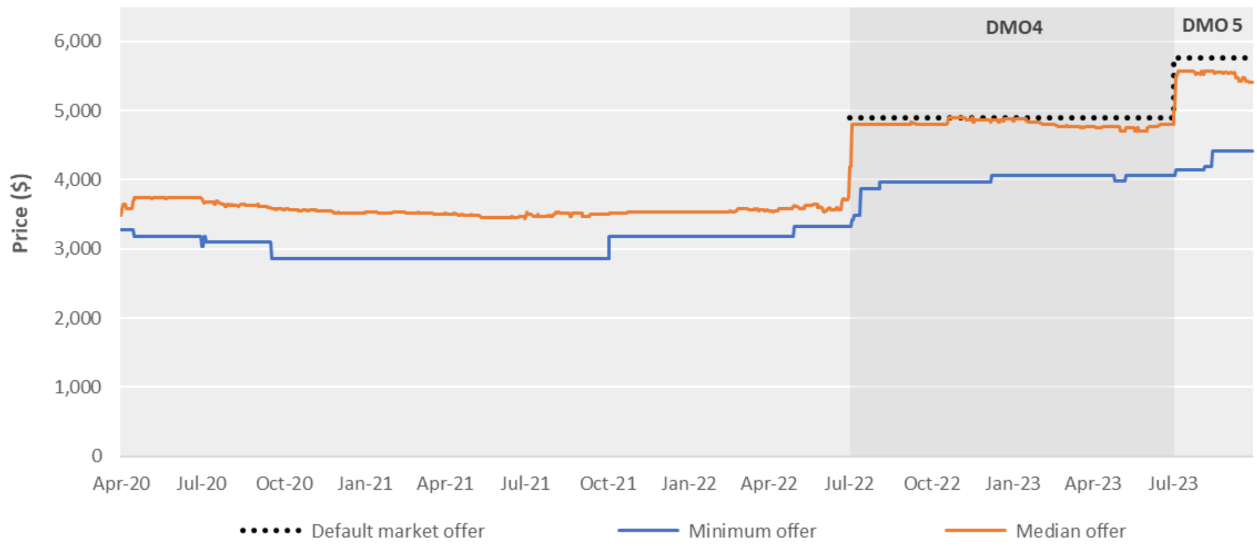
Figure 11 DMO price and median and minimum market offers – Small Business



Essential Energy

Figure 12 DMO price and median and minimum market offers – Residential

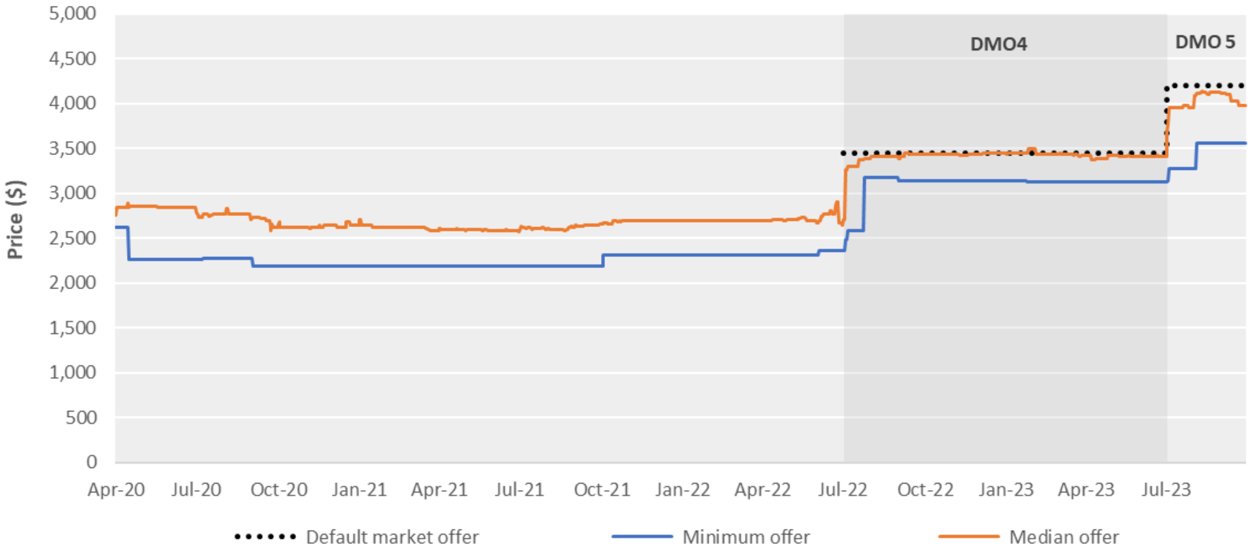
Figure 13 DMO price and median and minimum market offers – Small Business



Energex

Figure 14 DMO price and median and minimum market offers – Residential

Figure 15 DMO price and median and minimum market offers – Small Business



South Australian Power Networks

Figure 16 DMO price and median and minimum market offers – Residential

Figure 17 DMO price and median and minimum market offers – Small Business