Default market offer prices 2024–25

Draft determination

March 2024

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Tel: 1300 585 165

AER reference: 64687

Contents

Invitation for submissions

Interested parties are invited to make submissions on this draft determination by 9 April 2023. We will consider all submissions received by this date in our final determination.

Submissions can be sent to DMO@aer.gov.au, or to:

Daniel Harding
General Manager (A/g), Market Performance Branch
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Please ensure submissions are 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 note their confidentiality claim in the email attaching the submission. Ensure it clearly identifies the information that is the subject of the confidentiality claim and 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).[1]

1 ACCC/AER Information Policy, 4 June 2014

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
ACOSS	Australian Council of Social Services
ACS	Alternative Control Services
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CL	Controlled load
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
DMO 5	Default market offer determination for 2023–24
DMO 6	Default market offer determination for 2024–25
DNSP	Distribution Network Service Provider
EBITDA	Earnings before interest, taxes, depreciation, and amortisation
ECA	Energy Consumers Australia
ESC	Essential Services Commission
GST	Goods and services tax
GWh	Gigawatt hours
ICRC	Independent Competition and Regulatory Commission
kW	Kilowatts
kWh	Kilowatt hours
MSATS	Market Settlement and Transfer Solutions
MWh	Megawatt hours
NEM	National Electricity Market
OTC	Over-the-counter
OTTER	Office of the Tasmanian Regulator
PIAC	Public Interest Advocacy Centre
PV	Photovoltaic system / solar power system
RBA	Reserve Bank of Australia
RET	Renewable Energy Target
SACOSS	South Australian Council of Social Service
SAPN	SA Power Networks
SE Queensland	South-east Queensland
TOU	Time of use
WEC	Wholesale energy cost
QCA	Queensland Competition Authority

1 Executive summary

This is the AER's draft determination for retail electricity default market offer (DMO) prices to apply from 1 July 2024 to 30 June 2025, known as DMO 6.

1.1 The purpose of the DMO

The DMO protects consumers from unjustifiably high prices, while allowing retailers to recover their costs. It is the maximum price (or the 'price cap') that a retailer can charge a customer on a standing offer in New South Wales (NSW), South Australia and south-east Queensland (SE Queensland) each year. Standing offers are intended to provide a safety net for customers who have not engaged, or cannot engage, in the retail electricity market.

The Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 (the Regulations) require the AER, in setting the DMO, to determine what it considers would be a reasonable per-customer annual price, having regard to the costs of supply and enabling retailers to make a reasonable profit.

Further details on the background of the DMO and our price setting process are detailed in chapter 3 of this draft determination.

1.2 Market drivers of draft DMO 6 prices

Wholesale market costs are one of the largest components of the DMO prices comprising around 40% of the DMO. Conditions in wholesale markets have stabilised significantly since DMO 5. For example, as at February 2024, base futures contract prices have fallen by between 44% and 51% compared with their respective highs in October 2022. However, as retailers were purchasing some contracts for the DMO 6 period during the high priced period, the trade weighted average contract prices have not fallen as dramatically as the point-in-time comparison suggests. This progressive accumulation of contracts is how retailers manage price risks for future periods but it also results in a lag in changes in contract prices being passed on to consumers.

The overall outcome of this market stabilisation is a reduction in wholesale energy costs in DMO 6 of approximately 19% in SA Power Networks (SAPN) and between 5% and 10% across NSW. In the Energex region of Queensland, wholesale costs have remained relatively flat. This is mainly due to an increase in the cost of cap contracts in Queensland for next summer and higher costs from hedging strategies during daylight hours.

Network costs are also a large component of DMO prices, comprising around 40% of the DMO. During February 2024, the AER received updated network tariff estimates from each distribution network service provider (DNSP), which showed increases ranging from 9% (Endeavour) to 20% (Essential). Drivers of these increases include adjustments for recovery of revenue in prior years, updated capital and operating costs, CPI and interest rates, and, for the NSW networks, the NSW Renewable Energy Zone roadmap cost contribution allocations (determined and gazetted by the AER annually). While this is currently the best available information, the DMO 6 final determination will use the approved network tariffs for 2024–25.

Retail and other costs are a smaller component of the DMO (around 11% for residential customers and 7% for small business). However, this component has increased in DMO 6 as a result of the current economic outlook, including the high inflation rate and growing costs reported to the ACCC by retailers, including bad debts (which includes doubtful debts) and the costs of managing bad debt.

1.3 Our approach to DMO 6

The Default market offer prices 2024–25 issues paper (issues paper) was published on 5 October 2023. In the issues paper we consulted on various components relevant to the DMO 6, including:

- whether to continue use of the Net System Load Profile (NSLP), or a blended profile that incorporates interval meter data, and if so, how to appropriately account for solar PV exports
  - an additional consultation paper was also released in February 2024, seeking stakeholder feedback on alternative NSLP options
- whether alternative methodologies to calculating a retail margin or allowance could better balance the DMO objectives of price protection and incentivising competition and consumer engagement
- changes in smart meters installation costs in anticipation of the AEMC smart meter review outcomes and the 2025–2030 accelerated rollout in NECF regions.

1.3.1 Wholesale methodology

NSLP

To account for the continuing uptake of interval meters, the DMO 6 draft determination is based on blended load profiles which incorporate interval meter data. Due to the issues identified with the NSLP datasets for SAPN and Energex that were a result of an interim algorithm adjustment made by AEMO as it adapted to new settlement rules, we have modelled two separate wholesale costs then adopted a mid-point between the two.
The two alternative NSLP options were evenly balanced in terms of merits and disadvantages in accurately reflecting load profile shapes and subsequent retailer costs for the DMO 6 period. Because they produced materially different results and stakeholder feedback was also mixed, we consider that the mid-point between the two strikes the appropriate balance between allowing retailers to recover costs, while not resulting in an over-recovery from consumers.

We have excluded rooftop solar exports from the interval meter dataset used to create the blended load profiles. The DMO wholesale methodology is based upon hedging against consumption (or load), so we do not consider it appropriate to include the impact of exports (or generation) in the load profiles. This is also appropriate because the methodology does not account for the strategies available to retailers to manage a peakier load shape resulting from solar exports. Therefore, to include exports would likely result in an over estimation of actual retailer costs.

We note that the resulting blended load profiles have been flattened by the presence of small business load. Small business interval meter load predominately occurs during daylight hours and currently accounts for a large volume of interval meter consumption. This may shift as more residential customers receive interval meters in coming years.

South Australian methodology

We continued to collect over-the-counter (OTC) contract market data for DMO 6, this time focusing on South Australia, due to the low volumes of ASX traded contracts. There continues to be a general alignment in terms of prices, of comparable OTC contracts to ASX contracts. Therefore, we have continued to base the wholesale methodology on the publicly available ASX data only.

We continue to hold concerns about the low levels of traded volumes for DMO 6 products in South Australia. Although we have not made any changes to the current methodology, we continue to seek additional data that assists us in ensuring the wholesale cost is reflective of operating in the South Australian market.

1.3.2 Retail allowance changes to efficient margin and competition allowance

The AER's approaches to calculating the retail allowance have historically reflected the conditions in the market from before the DMO's introduction in 2019. For DMO 6 we have:

- considered the need for the retail allowance to be set such that its methodology is adaptable to the current market landscape
- provided a stable and predictable framework for calculating margin and allowance in future DMOs
- met and appropriately balanced the DMO objectives
- allowed a prudent retailer faced with the typical costs of supplying electricity to customers to achieve a reasonable profit.

Our proposed new approach involves separately calculating a retailer margin and a competition allowance in the DMO prices.

The retail margin is based on our view of a reasonably efficient margin as a percentage of the DMO price. This margin allows retailers to make a reasonable profit when selling electricity to standing offer customers in DMO regions. We have also determined a competition allowance that is applied after the retail margin is calculated. This reflects the higher costs of some of the smaller retailers in the market who enter and bring competitive tension which benefits customers. We have decided to not add the competition allowance onto the DMO price this year to take account of current economic and market conditions. We have also set out the framework we will use for making such adjustments in the future.

We have set the efficient margin at 6% and 11% of residential and small business prices respectively.

Our considerations and updated methodology are outlined in chapter 8 of this draft determination.

1.3.3 Advanced meters

We benefited from specific advanced meter installation projections provided by 10 retailers, and we considered and compared these projections with historic installation rates. We have proposed to continue the current approach of using historic installation data, which we consider is a more accurate approach, until formal legacy meter retirement plans are in place in July 2025. At this time, the retailers will have a firm idea of working capital costs and the rate of meter replacement for each year. Outlined further in chapter 4, for DMO 6, we propose to include a cost of capital estimate to cover potential installations in the DMO 6 period.

However, we will seek updated installation data from retailers before the DMO 6 final determination to ensure metering inputs are as current as possible.

1.4 DMO 6 draft prices

The price for residential customers without controlled load in SE Queensland is $2,022 which is an increase of 2.7%. For customers with controlled load, the price is $2,363, which is unchanged from DMO 5 (these amount to decreases of 0.6% and 3.3% below forecast inflation).[2]

In South Australia the price for residential customers without controlled load is $2,222, a reduction of around 2.5% since DMO 5 (5.8% below forecast inflation). Those with controlled load face a price of $2,773, which is a 0.5% decrease (3.8% below forecast inflation).

In NSW, residential customers without controlled load will see prices of $1,773 to $2,549 which range from a decrease of 3% to an increase of 0.9% (6.3% to 2.4% below forecast inflation) compared with DMO 5, depending on their distribution network region. Customers with controlled load will see prices of $2,476 to $2,964, amounting to decreases 0.4% to 7.1% (3.7% to 10.4% below forecast inflation).

For small business customers, prices will be between $4,191 and $5,802. Compared to DMO 5 these prices represent a 9.7% decrease to a 0.7% increase (13% to 2.6% below forecast inflation) depending on their region.

These outcomes are based on indicative network prices for 2024–25 and are expected to change once final prices are approved.

Where customers receive government rebates and concessions, the effective price they pay for electricity will be lower. Bill relief is currently offered by the Commonwealth, Queensland, NSW and South Australian Governments. Consumers can identify which forms of assistance they may be eligible for at https://www.energy.gov.au/rebates.

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[2] We have used Reserve Bank of Australia (RBA) February 2024 forecasted inflation for June 2024 (3.3%) and June 2025 (3.1%), RBA February 2024 forecast for the two years ending Jun 2025.

2 DMO 6 draft prices

Draft DMO prices for 2024–25 for each customer type in each distribution region are set out in Table 2.1. The table also shows the changes from DMO 5 in both real terms (that is, adjusted for forecast inflation) and nominal terms. The draft DMO prices are based on the most recent data available. The draft prices will be adjusted for the DMO 6 final determination as required based on:

- updated data received
- how market conditions have developed
- following public consultation.

Table 2.1 DMO 2024–25 draft determination prices, including changes from DMO 5 (nominal and real terms) *

Distribution zone		Residential (without CL)	Residential (with CL)	Small business (without CL)
Ausgrid	DMO Price	$1,773	$2,476	$4,512
	For annual usage of	3,900 kWh	Flat rate 4,800 kWh + CL 2,000 kWh	10,000 kWh
	DMO 5	$1,827	$2,562	$4,999
	Change y-o-y	-$54 (-3.0%)	-$86 (-3.4%)	-$487 (-9.7%)
	Change y-o-y (real)	-$114 (-6.3%)	-$171 (-6.7%)	-$652 (-13%)
Endeavour	DMO Price	$2,185	$2,766	$4,394
	For annual usage of	4,900 kWh	Flat rate 5,200 kWh + CL 2,200 kWh	10,000 kWh
	DMO 5	$2,228	$2,977	$4,598
	Change y-o-y	-$43 (-1.9%)	-$211 (-7.1%)	-$204 (-4.4%)
	Change y-o-y (real)	-$117 (-5.2%)	-$309 (-10.4%)	-$356 (-7.7%)
Essential	DMO Price	$2,549	$2,964	$5,802
	For annual usage of	4,600 kWh	Flat rate 4,600 kWh + CL 2,000 kWh	10,000 kWh
	DMO 5	$2,527	$2,977	$5,761
	Change y-o-y	+$22 (+0.9%)	-$13 (-0.4%)	+$41 (+0.7%)
	Change y-o-y (real)	-$61 (-2.4%)	-$111 (-3.7%)	-$149 (-2.6%)
Energex	DMO Price	$2,022	$2,363	$4,191
	For annual usage of	4,600 kWh	Flat rate 4,400 kWh + CL 1,900 kWh	10,000 kWh
	DMO 5	$1,969	$2,363	$4,202
	Change y-o-y	+$53 (+2.7%)	$0 (0%)	-$11 (-0.3%)
	Change y-o-y (real)	-$12 (-0.6%)	-$78 (-3.3%)	-$150 (-3.6%)
SAPN	DMO Price	$2,222	$2,773	$5,368
	For annual usage of	4,000 kWh	Flat rate 4,200 kWh + CL 1,800 kWh	10,000 kWh
	DMO 5	$2,279	$2,787	$5,849
	Change y-o-y	-57 (-2.5%)	-$14 (-0.5%)	-$481 (-8.2%)
	Change y-o-y (real)	-$132 (-5.8%)	-$106 (-3.8%)	-$674 (-11.5%)

*Real comparisons with DMO 5 are based on RBA 2023–24 inflation forecast of 3.3% in its [RBA February 2024 forecast for the two years ending Jun 2025].

3 The AER and DMO

The AER is an independent regulator responsible for enforcing the laws for the National Electricity Market (NEM) and spot gas markets in southern and eastern Australia. We report on the conduct of market participants and the effectiveness of competition, as well as regulate electricity networks and covered gas pipelines in all jurisdictions except Western Australia.

Across all of our functions and objectives we strive to maintain a healthy energy sector and protect the long-term interests of consumers.[3] We protect the interests of consumers by enforcing the National Energy Retail Law. Our retail energy market functions cover NSW, South Australia, Tasmania, the Australian Capital Territory (ACT) and Queensland. Under the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019, our role is to set the DMO price each year for non-price regulated network distribution regions – SE Queensland (Energex), NSW (Endeavour Energy, Essential Energy and Ausgrid) and South Australia (SAPN).

The DMO is a price cap. Retailers cannot charge above the DMO for their standing offers. The DMO price also acts as a 'reference price' for all other offers in each distribution region. DMO prices are designed to aid consumers in comparing energy plans across different providers.

3.1 Policy objectives guiding the DMO

Since its inception on 1 July 2019, the DMO has acted as a default protection for those who are not engaged in the market. It is not a low-priced alternative to a market offer.[4] When the DMO Regulations were introduced, the government also provided policy objectives.[5] These are matters that we consider are relevant when determining DMO prices:[6]

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

3 AER Strategic Plan 2020–25.

4 ACCC, *AER Default market offer, Submissions to the draft determination*, 20 March 2019, p. 1–2.

5 The DMO objectives are set out in several sources including: Treasurer's and Minister for Energy's request to the AER to develop a DMO, 22 October 2018, the ACCC Retail Electricity Pricing Inquiry final report ACCC Retail Electricity Pricing Inquiry final report, June 2018, and the Explanatory Statement accompanying the DMO Regulations, 2019.

6 The AER must have regard to…any other matters we consider relevant, Regulations s.16(4)(d).

The Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 also require us to consider a range of specific factors in determining a reasonable annual price. These requirements are outlined further in section 3.2.

The DMO differs in its role to that of other regulated electricity prices set by other regulators in Victoria (the Essential Services Commission (ESC)), Tasmania (Office of the Tasmanian Economic Regulator)(OTTER), the ACT (Independent Competition and Regulatory Commission)(ICRC) and for regional Queensland (Queensland Competition Authority)(QCA).

Guidance provided at the inception of the DMO was that its objectives are not the same as for these other regulated prices. For regional Queensland, the ACT and Tasmania, where there is limited retail electricity competition, the regulated prices are intended to be efficient prices in markets, due to the lack of competitive tension between retailers.

In Victoria, where there is retail competition, the objectives for the ESC in setting the Victorian Default Offer (VDO) are similar to those of the DMO in that it must be a 'simple, trusted and reasonably priced electricity option that safeguards consumers unable to engage in the electricity retail market'. However, the pricing order expressly states that the ESC must not include headroom, which is defined as an allowance that does not reflect efficient costs, and may only include modest costs for consumer acquisition and retention.[7]

In response to the issues paper, the Australian Government Minister[8] provided a submission that urged the AER to factor the recent cost of living crisis into our methodology and analysis. Additionally, the NSW Minister[9] submission encouraged the AER to reconsider the current retail allowance methodology to limit any compounding impacts on consumers' bills. The Queensland Minister's submission also requested that the AER factor cost of living pressures into our considerations, consider whether retailer headroom is needed and if lower margins would be sufficient, noting the comparison to the Victorian Default Offer which also has lower margins.[10]

The NSW Minister also asked us to consider an extension of the DMO protections to capture those customers living in embedded networks.

We support broadening the current DMO protections to customers in embedded networks in DMO regions. This approach would align pricing protections for DNSP-connected and embedded network customers. This approach would also afford similar pricing protections for both embedded network customers supplied by authorised retailers and exempt sellers. The AER considers it appropriate for all consumers to receive similar pricing protections regardless of the nature of their connection.

We made submissions[11] responding to the Australian Government 2022 review of the Regulations, which included how to extend the price cap protection provided by the DMO to embedded network customers. We look forward to the outcome of the review of the Regulations.

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7 Order made pursuant to s. 13, *Electricity Industry ACT 2000*.

8 The Hon Chris Bowen MP, *Submission to the issues paper*, undated.

9 The Hon Penny Sharpe MLC, *Submission to the issues paper*, 8 November 2023.

10 The Hon Mick de Brenni, *Submission to the issues paper*, 5 March 2024.

11 AER, *Submission to the DCCEEW directions paper*, 2 February 2022, *Submission to the DCCEEW discussion paper*, 8 October 2021.

3.2 Standing offer customers

The AEMC and Australian Competition and Consumer Commission (ACCC) have identified customers on standing offers as 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).

have moved into a premise and receive supply from the existing retailer supplying the premises but are yet to contact the retailer.[12]

have defaulted to a standing offer following the expiry of a market contract.[13]

Every retailer must have a standing offer and customers have the right to ask for one.[14]

However, for those with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms.[15] Therefore, customers seeking a standing offer can make that request of their existing retailer, knowing it will be met and that they will be protected by the DMO price cap. Retailers must ensure they comply with this obligation.[16]

In regions where the DMO is applied, a minority of residential and small business customers are on standing offers. Table 3.1 presents the number of customers on standing offers in DMO areas. Most customers on standing offers are served by 'Tier 1' retailers – AGL, EnergyAustralia and Origin Energy.

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

13 The Regulations, s. 10, 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.

14 National Energy Retail Law S. 23 and S. 25

15 National Energy Retail Law S. 22

16 ACCC and AER, [Joint Compliance Bulletin](), May 2023

Table 3.1 Customers on standing offers in DMO areas

Customer type	DMO	NSW (number and % of customers)	SE Queensland (number and % of customers)	SA (number and % of customers)	Total standing offer customers (number and % of customers)
Residential customers	DMO 6	293,470 (8.6%)	140,713 (9.4%)	61,701 (7.6%)	**495,884 (8.6%)**
Small business customers	DMO 6	57,093 (18.2%)	23,106 (19.7%)	14,600 (16.7%)	**94,799 (18.3%)**
Residential customers	DMO 5	320,362 (9.4%)	156,986 (10.5%)	62,600 (7.8%)	**539,948 (9.5%)**
Small business customers	DMO 5	55,995 (18.1%)	21,267 (19.3%)	13,778 (15.9%)	**91,040 (18.0%)**
Residential customers	DMO 4	347,484 (10.3%)	159,492 (10.8%)	63,411 (8.0%)	**570,368 (10.2%)**
Small business customers	DMO 4	60,204 (18.6%)	22,394 (20.6%)	13,906 (16.0%)	**96,504 (18.1%)**
Residential customers	DMO 3	368,180 (11.1%)	175,453 (12.1%)	68,873 (8.7%)	**612,506 (11.1%)**
Small business customers	DMO 3	74,356 (22.2%)	26,053 (23.5%)	13,907 (15.8%)	**114,316 (21.6%)**

Note: SE Queensland figures extrapolated from all Queensland by excluding Ergon customers. Other retailers have customers in regional Queensland so figure is approximate. Standing offer customers calculated by subtracting market offer customers from total customers.
Source: AER Retail Market Performance update, Quarter 2 2022–23.

The Regulations also prescribe a mandatory industry code with DMO reference provisions requiring:[17]

- standing offer prices for small customers not to exceed a price determined by the AER[18]
- small customers to be told how a retailer’s prices compare with the AER determined annual price[19]
- the most prominent price related feature in an advertisement must not be a conditional discount, and any conditions on other discounts are clearly displayed.[20]

17 The Code for the purposes of Part IVB of the *Competition and Consumer Act 2010*.

18 Regulations s. 10.

19 Regulations s. 12.

20 Regulations s. 14.

Under these requirements, the DMO price acts as a 'reference price', against which customers can easily compare market offers. The ACCC is responsible for enforcement and compliance with these provisions.

3.3 DMO regulatory framework

The legislative framework for implementing DMO prices and the reference bill mechanism are contained in the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019.

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[21] (the model annual usage)[22]
- 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).[23]

The DMO price applies to residential and small business customers on standing offers in NSW, South Australia and SE Queensland.[24]

The Regulations set out that we must determine DMO prices for:

- residential customers – on flat rate or time of use (TOU) tariffs
- residential customers with controlled load – these are separately metered tariffs used for appliances such as electric hot water storage systems, pool pumps or underfloor heating
- small business customers – on flat rate tariffs.[25]

Each category includes customers with solar tariffs.[26]

The Regulations require us to consider a range of specific factors in determining a reasonable annual price.[27] These include wholesale electricity, network and retail costs, costs to acquire, retain and serve customers, the principle that a retailer should be able to make a reasonable profit and other matters we consider relevant.

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

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

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

24 Regulations, s. 8, 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.

25 Small business customers are those who use less than 100 MWh per annum.

26 We are not 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 and tariffs offered in embedded networks.

27 Regulations, s. 16(4).

4 Network costs

Under the National Electricity Rules, the AER regulates network charges, while the distributors set those network charges annually, offering a range of tariff structures for each class of customer. The DMO network cost component is adjusted each year to reflect changes in distributor network costs for the relevant customer class.[28]

The network costs used in the draft determination are based on updated indicative network tariffs for 2024–25 provided by distributors in February 2024, which are considered the best estimates and latest cost impacts (for example, adjustments for recovery of revenue in prior years, updated capital and operating costs, CPI and interest rates). Further information relevant to the annual network pricing process will become available after the release of this draft determination. While the scale is uncertain, we expect that transmission costs and cost of debt updates will further increase the network price component of DMO 6 in some regions. The DMO 6 final determination will use the approved network tariffs for 2024–25.

4.1 Issues paper

4.1.1 Calculation of network costs

In the issues paper we identified that there has been a growing proportion of customers moving to an underlying TOU network tariff over the past 2 DMO periods, which raises the question of whether to include TOU consumption data in our calculation of the network costs for the DMO.

We asked whether our prior approach of using a flat tariff was still appropriate to determine network costs, or whether a blended approach should be considered.

An alternative approach proposed was to develop a blended network profile that also captured TOU tariffs. The rationale for that approach was to include the growing proportion of customers on TOU tariffs we had identified.

In considering whether to use a blended network tariff estimate (based on proportion of customers on a flat tariff and a TOU tariff), the AER analysed the Australian Energy Market Operator (AEMO) half hour daily network Market Settlement and Transfer Solutions (MSATS) dataset for residential customers with interval meters. From that analysis we identified that data inconsistencies prevented us from using a blended approach. This is explained in further detail in section 4.3.1.

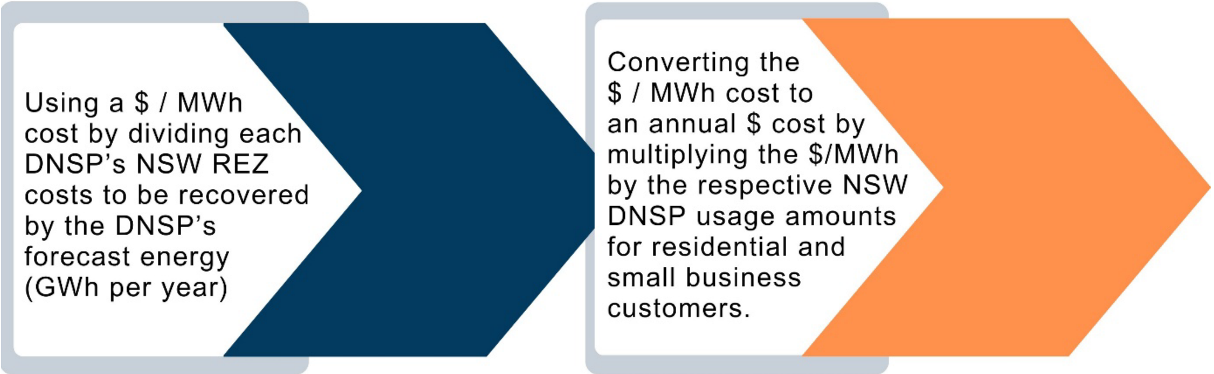
4.1.2 NSW DNSP revenue reset and NSW roadmap costs

The NSW distribution businesses (Ausgrid, Endeavour Energy and Essential Energy) are developing their revenue determinations for 2024–2029. The timing for the completion of this process is late April 2024.

The AER determines and gazettes the NSW roadmap costs annually. A prior estimate of NSW roadmap costs (on a $ per year basis) was used in the DMO 5 draft determination for residential and small business customers.

For DMO 5, we developed the NSW roadmap estimate by:

[28] Table 4.1 identifies the network tariffs used for the DMO.



4.2 Stakeholder views

4.2.1 Calculation of network costs

Seven retailers provided feedback in response to whether network costs should be based on a blend of flat rate and time of use network tariffs. Stakeholders had mixed positions on this topic.

Three retailers were in support of the approach to move to a blend of flat and TOU tariffs. These submissions suggested that this could be achieved by establishing an average consumption profile for each network/customer type and weighing this by volume/customer numbers to derive a blended cost estimate.[29] Another retailer acknowledged the complexity and loss of transparency in this approach as a concern to be considered. [30]

Three retailers encouraged the AER to maintain the current methodology of using a flat rate, noting that such a process reflected a reasonable approach, which ensures regulatory consistency and maintains transparency. [31]

4.2.2 NSW DNSP revenue reset

We received several responses to our proposed approach for estimating NSW DSNP tariffs given that approved tariffs would not be available to use for the DMO 6 draft determination. Various stakeholders considered the timing to be extremely tight to both assess and approve these prices for inclusion in the DMO. They encouraged the AER to maintain the current approach and develop the work program to determine a best estimate from DNSPs for the draft determination that more closely reflects expected tariffs in the DMO 6 final determination.[32]

A number of stakeholders suggested we use the previously submitted pricing proposals for 2024–25 in the absence of updated and approved network prices. The 2024–25 price estimates were submitted by the DNSPs with the annual pricing proposals for 2023–24.

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29 Simply Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 5; 1st Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 4; Powershop, *Submission to DMO 6 issues paper,* 3 November 2023, p. 7.

30 Alinta Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 8.

31 Momentum Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 5; EnergyAustralia, *Submission to DMO 6 issues paper,* 3 November 2023, p. 9; Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 8.

32 Origin Energy, *Submission to DMO 6 issues paper,* 3 November 2023, pp. 2, 18; Alinta Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 3; Red and Lumo Energy, *Submission to DMO 6 issues paper,* 9 November 2023, p. 5.

4.3 Draft determination

4.3.1 Calculation of network costs

We note that individual customers have different consumption patterns which may result in higher or lower network charges under a TOU tariff relative to the fixed rate tariff. Our consideration was not solely costs, but instead, the best methodology that most accurately reflects the costs a retailer incurs.

We analysed the AEMO data over a 3-year period (1 October 2020 to 30 September 2023) by jurisdiction, by season and by TOU (peak, off-peak and shoulder) to determine a daily average TOU profile by season and by day of the week. These profiles were aggregated and applied to the DNSP's TOU tariffs to determine a TOU network cost.

Our analysis found mixed results, indicating that blending network tariffs could result in network costs that were lower or higher than our existing methodology, which only uses flat rate tariffs, depending on the region.

However, the MSATS consumption data includes a level of controlled load consumption, that cannot currently be fully identified and separated from the aggregate MSATS interval consumption data. This will lead to the analysis having a much greater allocation of energy into off-peak and shoulder charging times in our calculations.

Given the current inability to identify and remove controlled load data in the MSATS dataset, the DMO 6 draft determination will continue to base the DMO network costs for customers on flat rate tariffs only. However, we will continue to monitor cost differences between tariff types, and the number of customers on different tariff types, to ensure our methodology remains appropriate and reasonable.

Table 4.1 identifies the network tariffs used in the DMO and table 4.2 identifies the AER estimate of network costs.

Table 4.1 Network tariffs (with network codes) to assess the change in network costs

Distribution region	Residential flat rate	Residential controlled load	Small business flat rate
Ausgrid	Residential Non-TOU - EA010	EA030 – Controlled load 1 EA040 – Controlled load 2	EA050 Small business non-TOU
Endeavour	Residential Flat tariff - N70	Controlled load 1 N50 Controlled load 2 N54	General Supply Block Tariff N90
Essential	Residential Anytime BLNN2AU	Energy Saver 1 BLNC1AU Energy Saver 2 BLNC2AU	Small Business Anytime BLNN1AU
Energex	Residential Flat NTC8400	Super Economy NTC9000 Economy NTC9100	Business Flat NTC8500
SAPN	Residential Single Rate RSR (SR)	Residential Single Rate RSR (controlled load)	Business Single Rate BSR

Table 4.2 AER estimate of 2024–25 network costs (including GST)

Distribution region	Tariff	2023–24 ($)	2024–25 ($)	Change: year-on-year ($)	(%)
Ausgrid	Residential flat rate	$565	$637	$72	12.7%
	Residential controlled load	$741	$834	$94	12.6%
	Small business 10,000 kWh	$1,478	$1,652	$175	11.8%
Endeavour	Residential flat rate	$679	$746	$67	9.9%
	Residential controlled load	$812	$915	$103	12.7%
	Small business 10,000 kWh	$1,303	$1,420	$117	9.0%
Essential	Residential flat rate	$1,083	$1,220	$137	12.7%
	Residential controlled load	$1,208	$1,338	$131	10.8%
	Small business 10,000 kWh	$2,339	$2,814	$475	20.3%
Energex	Residential flat rate	$669	$747	$77	11.5%
	Residential controlled load	$754	$844	$89	11.8%
	Small business 10,000 kWh	$1,293	$1,431	$138	10.7%
SAPN	Residential flat rate	$843	$925	$82	9.8%
	Residential controlled load	$1,007	$1,112	$104	10.4%
	Small business 10,000 kWh	$2,022	$2,209	$187	9.2%

4.3.2 NSW DNSP revenue reset

The DMO 6 draft determination will continue to rely on estimates of their network tariffs for 2025–26 from the NSW DNSPs. The DMO 6 final determination will be based on the DNSP network tariffs approved by the AER as at mid-May 2024.

4.3.3 Treatment of NSW roadmap costs

At the time of this DMO draft determination, the AER has determined a costs amount of $341.25 million to be recovered via the NSW network tariffs. For each DNSP, the costs to be recovered are:

- Ausgrid: $151.13 million
- Endeavour: $123.40 million
- Essential: $66.72 million.

These allocations are based on each network's volume of electricity transported and peak demand.

In the issues paper we anticipated that network prices from NSW DNSPs would not reflect cost recovery of these 2024–25 NSW roadmap costs. In the issues paper we proposed to adopt the same approach as the DMO 5 draft determination, which was to separately estimate NSW roadmap costs on a per customer basis.

Since publishing the issues paper, the NSW DNSPs have developed network prices that do include recovery of the 2024–25 NSW roadmap costs. As a result, we do not need to separately estimate NSW roadmap costs because they are now included in the updated estimate of network costs.

5 Wholesale energy costs

5.1 Issues paper

The issues paper invited stakeholders to provide feedback on potential refinements to the wholesale methodology. It particularly sought comments on the integration of interval meter data in our estimation of load profiles and how to best estimate the cost of hedging in South Australia, given the scarcity of publicly available contract market data.[33] We also called for submissions on the wholesale energy cost methodology more generally, which are discussed in section 5.1.3 'Other wholesale cost issues'.

We published a supplementary consultation paper in February 2024 to test stakeholder views on how to approach changes to the Net System Load Profile (NSLP) data in our wholesale methodology.

5.1.1 Load profile assumptions

We have historically relied on the NSLP and Controlled Load Profile (CLP) to model the costs to retailers of purchasing energy for residential and small business customers. In the issues paper we highlighted increasing penetration of interval meters driven by household solar uptake across relevant DMO regions. We asked stakeholders if they supported moving to a blended load profile, which combined interval meter data and the NSLP or CLP. Additionally, we asked how household solar PV exports within the interval meter data should be treated, noting that including the impacts of exports would result in a greater daytime carve-out of demand. We also asked if stakeholders had concerns about data transparency, because the interval meter dataset is not publicly available.

In February 2024 we released a consultation paper on the NSLP, which sought stakeholder feedback on whether alternative options to produce load profiles based on the NSLP were needed, due to recently identified issues with the SAPN and Energex data. These issues were a result of an interim adjustment made by AEMO to account for unusual outcomes occurring in settlement volumes, following the implementation of 5-minute settlement. The consultation paper highlighted 3 options for stakeholders to consider:

- use the NSLP data as published by AEMO
- undertake a manual adjustment to the NSLP data
- continue to use the NSLP data from DMO 4 and DMO 5 (however, we stated in the consultation paper that we did not consider this option would be reflective of a retailer's load shape for the DMO 6 period given its age and that we would be unable to blend it with coincident interval meter data).

Other load profile assumptions

The issues paper sought stakeholder views on developing separate load profiles for residential and small business customers. We also indicated we were considering replacing the individual load profiles for each distribution network in the NSW region with a singular load profile.

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33 The majority of interval meter data comes from type 4 and 4A digital meters (smart meters), but this dataset may also include data readings from type 5 manually read interval meters (non-smart meters).

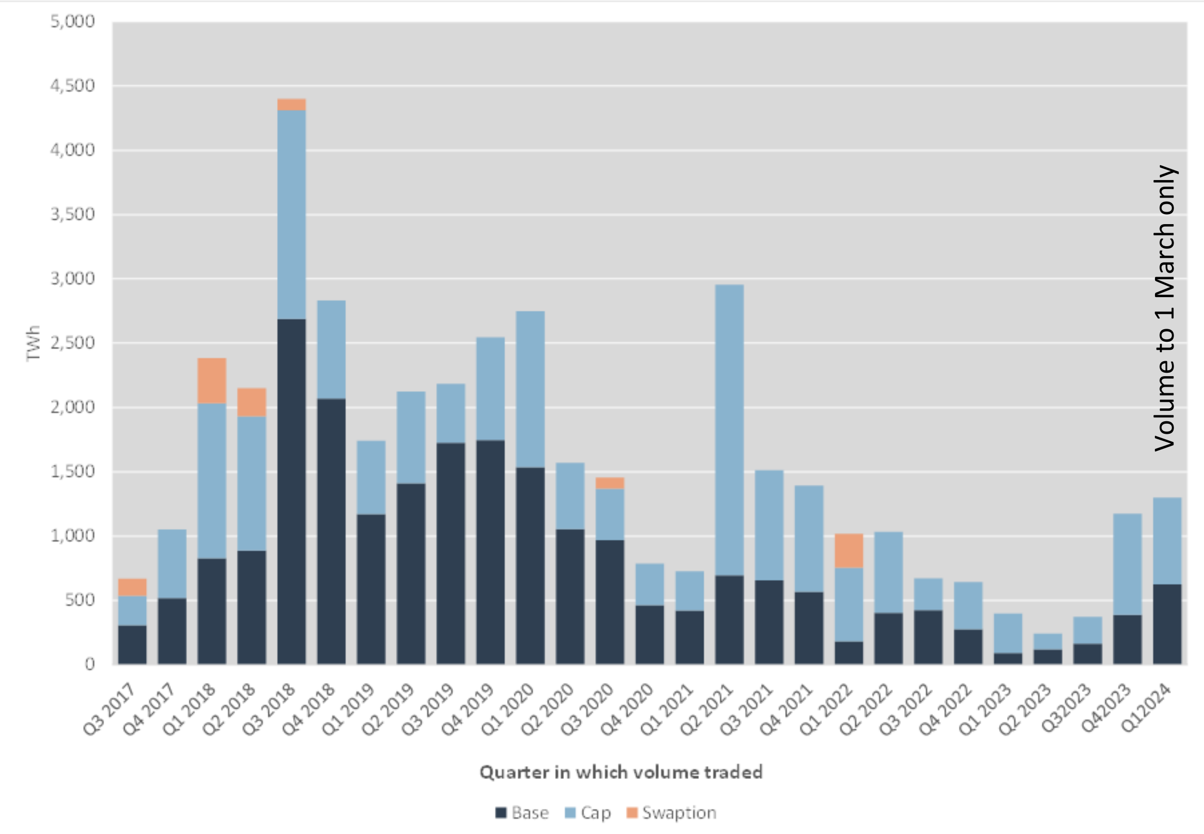
5.1.2 Use of over-the-counter confidential contract information

Our current wholesale methodology uses publicly available ASX trade data to price futures contracts for base and cap contracts. Traded volumes arising from the exercise of base strip options (swaptions) are also included. This methodology relies on a liquid contract market, where retailers can actively acquire contracts in the years leading up to the DMO period.

The issues paper highlighted continuing concerns about the liquidity of the South Australian contract market. We noted that limited traded volumes may create a risk that the ASX trade data was not reflective of a prudent retailer's hedging costs and that additional contract products or methodologies may be necessary to determine the wholesale cost component of the DMO.

ASX traded volumes in Queensland and NSW have remained steady and there are still reasonable levels of exchange traded contract types trading across the DMO 6 financial year 2024–25. Conversely, ASX traded volumes in South Australia have remained at very low levels despite an increase in traded volumes from late 2023 (Figure 5.1).

Figure 5.1 ASX electricity contracts traded volumes, South Australia



Source: AER analysis using ASX data.

As a result of continuing low levels of traded volumes in South Australia, we collected a second tranche of OTC contracts covering 1 October to 31 December 2023.

To better account for the lack of liquidity in South Australia, the issues paper also sought stakeholder feedback on what additional data should be considered when assessing contract pricing for DMO 6. We asked stakeholders 2 further questions:

- Are there other methodologies the AER could investigate to determine the wholesale cost in South Australia?

- Would consideration of a retailer holding Victorian futures contracts with Settlements Residue Auctions (SRAs) be reflective of the practice of a reasonable retailer? How would we model this?

5.1.3 Other wholesale cost issues

The issues paper discussed treatment of a range of other aspects of the wholesale cost methodology. While we did not propose making any changes to these aspects of the methodology, we welcomed stakeholder views on these issues:

- **75th vs 95th percentile**: The issues paper stated our intention to retain the use of the 75th percentile of distributed wholesale cost estimates. At the 75th percentile retailers should be able to recover their costs, while consumers are not allocated an excessive amount of risk.
- **Length of the book build period:** In our issues paper we indicated our intention to retain the use of all ASX trades across the most recent 2 to 3-year period in assessing our simulated book build. We consider this approach most accurately reflects the average costs of a prudent retailer over time, and results in a more stable DMO from year to year.
- **ASX options:** In our issues paper we stated our intention to retain the use of traded volumes arising from the exercise of options, including option premiums. We consider that ASX options provide valuable information on the cost of energy, which are readily available to retailers as a hedging product.
- **Changes to coal and gas caps:** The issues paper outlined our intention to reflect developments of government interventions in wholesale coal and gas markets in our wholesale cost modelling. Caps on the price of coal are due to end with the current financial year, while the new Gas Market Code extended the gas price cap until 2025. Both developments will be reflected in our modelling approach.

5.2 Stakeholder views

5.2.1 Load profile assumptions

Energex and SAPN NSLP options

In response to our February consultation paper on the treatment of load profiles, most submissions, including all submissions from retailers, supported a manual adjustment of the NSLP data.[34] Retailer submissions were uniform in considering that this approach, while imperfect, resulted in a more reflective retailer load profile shape for the DMO 6 period compared to the other 2 options presented. Origin Energy noted this approach has the additional benefit of rectifying issues with the NSLP dataset immediately, rather than deferring the decision for future DMO determinations. While EnergyAustralia and Alinta Energy supported a manual adjustment, they questioned how accurate the resulting data

[34] AGL, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; Alinta Energy, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; AEC, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; AEMC, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; EnergyAustralia, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 2; ENGIE, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; Origin Energy, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; Red Energy and Lumo Energy, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1.

would be, based on their own load profile shapes for residential and small business customers.

Retailers, the AEMC and the Australian Energy Council (AEC) supported a manually adjusted NSLP due to a lack of other suitable options.[35] AGL, Origin Energy, EnergyAustralia, Alinta Energy, ENGIE (Simply Energy) and Red Energy and Lumo Energy stated that using a non-adjusted NSLP would be an inaccurate reflection of their costs. The AEC stated that it would be inappropriate to use a non-adjusted NSLP because it is known to be incorrect. Many of the same stakeholders also discouraged the use of DMO 4 and DMO 5 load profiles to substitute the NSLP for DMO 6, on the basis that this data is too outdated to be an accurate reflection of retailer costs.

DCCEEW, the Queensland Department of Energy and Climate, the Public Interest Advocacy Centre (PIAC) and South Australian Council of Social Service (SACOSS) supported the use of a non-adjusted NSLP dataset. These stakeholders considered this approach to be the most transparent available option, which is a reasonable reflection of the costs retailers have faced. These submissions noted use of a non-adjusted NSLP was likely to produce a lower wholesale energy cost.[36]

The South Australian Department for Energy and Mining also supported the use of a non-adjusted NSLP dataset on the basis that the time before 1 October 2023 when AEMO removed its manual adjustment to metering data was longer than the subsequent period (in the time up to DMO 6). While acknowledging that it was generally supportive of amendments that more closely reflect retailers' costs, the department also questioned whether the period ACIL Allen used to make its adjustment would produce an accurate result. DCCEEW also noted that in practice retailers hedge against their specific load profiles, which vary depending on the underlying customer base, and it is challenging for the AER to determine a precise representative load profile.[37]

Adopting a blended load profile

All submissions from retailers supported moving towards a blended load profile for DMO 6.[38] These submissions considered that a blended load profile would produce a more accurate

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35 AGL, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 2; Alinta Energy*, Submission to NSLP approach consultation paper*, 20 February 2024, p. 3; EnergyAustralia, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 2; ENGIE, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; Origin Energy, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 2; Red Energy and Lumo Energy, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; AEC, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1; AEMC, *Submission to NSLP approach consultation paper*, 20 February 2024, p. 1.

36 DCCEEW, *Submission to NSLP approach consultation paper*, 23 February 2024, p. 2; PIAC/SACOSS, *Joint submission to NSLP approach consultation paper*, 20 February 2024, p. 2; The Hon Mick de Brenni, *Submission to the issues paper*, 5 March 2024.

37 SA Department for Energy and Mining, *Submission to NSLP approach consultation paper*, 22 February 2024, pp. 1–2; DCCEEW, *Submission to NSLP approach consultation paper*, 23 February 2024, p. 1.

38 GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1; Momentum Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2; 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 1,3; Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, p. 2; Energy Locals, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2.

reflection of a typical retailer's residential and small business customer load. SACOSS, while supportive of more accurate data being used, held concerns around the potential for customers without rooftop solar paying higher prices due to the impact of solar households on the shape of the load profile. The South Australian Department for Energy and Mining expressed concern that including interval meter data in the estimation of the load profile may result in a higher wholesale energy cost.

Submissions from Simply Energy, Origin Energy, Alinta Energy and Energy Locals recommended that the impacts from solar PV exports be included if a blended load profile is adopted. These retailers considered that this would more closely represent a load that a typical retailer hedges against. 1st Energy and Energy Locals noted that retailers can become exposed to negative spot prices when household solar exports result in a negative retail load, and recommended these costs be considered in the DMO 6 methodology. Powershop suggested the AER consider splitting customer load profiles into solar and non-solar, because resulting load profiles would differ significantly. Additionally, Powershop suggested separating customer profiles may better equip the DMO to capture advances in metering and other consumer energy resources in the future.

Regarding data transparency, most submissions requested as much data as possible or details of the methodology used to create the data be published but acknowledged the inherent gains in accuracy resulting from moving to a blended load profile were of greater importance.[39]

Other load profile assumptions

Retailers were the only stakeholders to provide feedback on whether there should be separate load profiles for residential and small business customers and introducing a singular load profile for NSW.

Retailers' views were varied on whether separate load profiles should be developed for residential and small business customers. Alinta Energy, Energy Locals and 1st Energy supported maintaining a single load profile because it reflects their combined portfolio approach to hedging. Alinta Energy recommended the AER revisit this issue in future DMO determinations considering the increasing availability of advanced meter data and assignment of customers to cost-reflective tariffs.[40]

Momentum Energy also supported a single load profile for residential and small business customers, stating that changing to separate load profiles, together with the introduction of a blended load profile, would create excessive complexity. AGL and EnergyAustralia recommended the AER maintain consistency in its approach by using a single load profile.[41]

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39 GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1; EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2; Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3; Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; PIAC/ACOSS/SACOSS, *Joint submission to DMO 6 issues paper*, 9 November 2023, p. 8.

40 Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 4–5; Energy Locals, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2.

41 Momentum Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2; EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, p. 8.

Conversely, several retailers submitted that the AER should develop separate load profiles, noting that residential and small business are distinct customer segments with markedly different load profiles. Simply Energy submitted that the AER could determine a single profile by developing separate load profiles and aggregating them based on their prevalence in the market. [42] Powershop stated that the AER should not assume all efficient retailers would adopt a combined portfolio approach to hedging, and load profiles should be reflective of true acquisition costs incurred. Powershop also queried whether there should be separate methodologies to determine a DMO for customers who have and have not upgraded to smart meters.[43]

Stakeholder views on introducing a singular load profile for NSW were mixed. Retailers that supported introducing a singular profile for NSW considered it would be more reflective of a retailer's approach to hedging in practice.[44]

Powershop, Simply Energy and Red Energy and Lumo Energy recommended the AER maintain separate load profiles for each distribution network in NSW because it better reflects a reasonable retailer’s approach and material differences in characteristics between different distribution networks. AGL also supported separate profiles because it valued consistency in the approach. Origin Energy considered that changing to a single load profile for NSW would be regressive if it further reduced the representation of solar customers in the NSLP of a given distribution network.[45]

The AEC noted that the AER in principle should use the best information it has available.[46]

5.2.2 South Australian wholesale methodology

Use of confidential contract information

Submissions from retailers and the AEC were generally supportive of the collection of OTC information. However, most indicated that the OTC contract information collected for South Australia should be considered as a substantive check on ASX data only. This is primarily due to participants’ concerns around transparency and the AER’s ability to ensure the integrity of the data.[47]

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42 GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3; Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, pp. 2–3; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2.

43 Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3.

44 EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7; Energy Locals, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; 1st Energy, Submission to DMO 6 issues paper, 3 November 2023, p. 2.

45 Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, p. 3; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3.

46 AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2.

47 GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Simply Energy, *Submission to DMO 6 issues paper*, 2; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 1; Alinta Energy; 2023, 3 November 2023, p. 2; 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023,

Simply Energy further noted that OTC contracts provide an understanding of the contracts used to hedge retail load in South Australia. It considered baseload swaps and caps were not effective hedging instruments in South Australia, because the South Australian wholesale market is predominantly comprised of renewables. To manage price and intermittency risk, large risk premiums need to be included in final hedge costs. [48]

Origin Energy, while supportive of the collection of OTC data that could be used as a benchmark against ASX data, did not support the use of additional contract products being included in the wholesale methodology. It considered the use of contract products such as power purchase agreements, weather derivatives and inter-regional hedging would materially reduce transparency.[49]

Momentum Energy submitted that OTC data lacks transparency and may present varying credit risks among participants. They did not support the use of OTC trade data and considered that it is not indicative of many retailers' hedging costs.[50]

AGL deferred its consideration of the use of OTC data until the DMO draft determination stage on the basis that the data at that point in time would provide a more accurate indication of the level of liquidity for the upcoming financial year. As in previous DMO submissions, they also indicated doubts as to whether the ASX data provides an accurate indication of the costs retailers face in South Australia.[51]

While SACOSS did not state a position on whether OTC contracts should be included in the South Australian wholesale methodology, it raised concerns about retailers hedging strategies and increasing wholesale costs for South Australian households.[52]

Other methodologies considered

Retailers and the AEC were opposed to using SRAs in combination with a Victorian hedge position as part of the DMO wholesale cost modelling for South Australia. The main concerns raised were the non-firm nature of SRAs and a lack of transparency.[53]

The AEC, Powershop and EnergyAustralia recommended the use of broker curves in response to the question of alternative methodologies that could be used to determine the

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p. 3; SA Department for Energy and Mining *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3; 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; AEC *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; Energy Locals *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; SACOSS, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2.

48 Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2.

49 Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 6.

50 Momentum, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2.

51 AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3.

52 SACOSS, *Submission to DMO 6 issues paper*, 3 November 2023, p. 12.

53 Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 6–7; Energy Locals, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 4–5; 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Momentum, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3; Alinta Energy*, Submission to DMO 6 issues paper*, 3 November 2023, pp. 2, 5; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, pp. 3–4; EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 8, 9.

wholesale cost in South Australia.[54] This was based on their view that these curves could reflect contract market activity more accurately.

SACOSS suggested considering the increasing energy revenue from batteries and how this might impact inputs into wholesale cost calculations.[55]

5.2.3 Other wholesale cost issues

75th vs 95th percentile

Retailers recommended the AER revert to using the 95th percentile of modelled cost outcomes because the 75th percentile is not reflective of a prudent retailer.[56]

AGL and 1st Energy considered that shifting to the 95th percentile was supported by the volatility in spot market outcomes over recent years, while the 75th percentile would significantly increase the risk that retailers' actual wholesale energy cost will exceed the AER's forecast allowance.[57] GloBird Energy further recommended the AER undertake a post-review of its modelled outcomes to determine the level of risk a retailer that did hedge at the 75th percentile would have faced.[58]

Length of book build period

Retailers provided differing views on the length of the book build period. Origin Energy supported a longer book build period because this would facilitate greater price stability. Other retailers highlighted the uncertainty in forecasting customer numbers and their consumption past 1 to 2 years, which does not align with a 2 to 3-year book build period.[59]

Several retailers recommended book build periods of varying length. Powershop, Energy Locals, 1st Energy and GloBird Energy supported a shorter book build period. Powershop considered that the book build period should be a range of 12–24 months due to the scale of change that occurs within the current period.[60] It explained that changes in demand and load profiles due to growing uptake of consumer energy resource technologies and other methods of electrification supported a shorter book build period. Similarly, Energy Locals noted that the liquidity of the wholesale market has been evolving, with the tenure of trades getting shorter. 1st Energy noted that a period of 18–24 months for the book build period would be more reflective of reality.[61] GloBird Energy considered that a 12 to 18-month book build

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54 AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2; Powershop and Shell Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 8, 9.

55 SACOSS, *Submission to DMO 6 issues paper*, 3 November 2023, p. 12.

56 AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3; 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1; AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 2, 5; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 8; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3.

57 AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 3. 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3.

58 GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1.

59 Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 8; Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Energy Locals, Submission to DMO 6 issues paper, 3 November 2023, p. 5; 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1.

60 Powershop, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4.

61 Energy Locals, Submission to DMO 6 issues paper, 3 November 2023, p. 5.

period strikes the right balance between price stability, retail cost and sustainable market competitiveness.[62]

Use of options

Momentum Energy suggested a more complex method of including the costs of option premiums paid by retailers for the wholesale methodology. This was based on volatility levels of options and the determination of costs occurring at the time of trade, rather than at the time positions are exercised.

5.3 Draft determination

Having considered stakeholder feedback, we have made the draft determination detailed below.

5.3.1 Load profile assumptions

Energex and SAPN NSLP options

For Energex and SAPN regions, we have decided to model separate Wholesale Energy Cost (WEC) estimates using AEMO's non-adjusted NSLP and ACIL Allen's adjusted NSLP, and adopt the midpoint of the two results as the final WEC input for DMO 6.

We consider the two options to be evenly balanced in their inherent merits and disadvantages, while noting they produce materially different results (Table 5.1). A non-adjusted NSLP would be more transparent, allow for greater continuity in methodologies between DMO determinations, and reflect the basis of settlement used for most of our book build period. However, it does not reflect the underlying load shape, nor the settlement approach that is likely to be used in the future.

Conversely, an adjusted NSLP which ACIL Allen considers appropriate, may better reflect an average retail load for the DMO 6 period and align more closely with AEMO's NSLP as published after the interim adjustment was removed in October 2023, likely allowing greater load profile continuity with DMO 7. However, it is peakier in some respects than the load shape that has emerged since AEMO's 1 October 2023 changes.

Table 5.1 WEC results of differing load profile options

Load profile option	Resulting WEC (per MWh)
Energex – AEMO non-adjusted NSLP	$141.28
Energex – ACIL Allen adjusted NSLP	$162.31
Energex – Midpoint	$151.79
SAPN – AEMO non-adjusted NSLP	$137.95
SAPN – ACIL Allen Adjusted NSLP	$168.32
SAPN – Midpoint	$153.14

Source: ACIL Allen

Given the data challenges with each option, we are concerned that use of a non-adjusted NSLP could result in an under-recovery of costs for retailers, while use of the adjusted NSLP could result in an over-recovery of costs from consumers. We consider that responses from

62 GloBird Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1.

stakeholders reflected this contrast. We chose to adopt a midpoint between the two approaches to ensure neither stakeholder group is disproportionately burdened by a transitory issue in the NSLP data. This is a risk-based approach in the context of a transition period with imperfect data sources. Further, while AEMO implemented a permanent solution for one element of the data issue in October 2023, it will make further adjustments for the remaining aspects from 29 September 2024, which could have some impact on NSLP data in the future. We will revisit this in DMO 7 based on NSLP data considerations at that time.

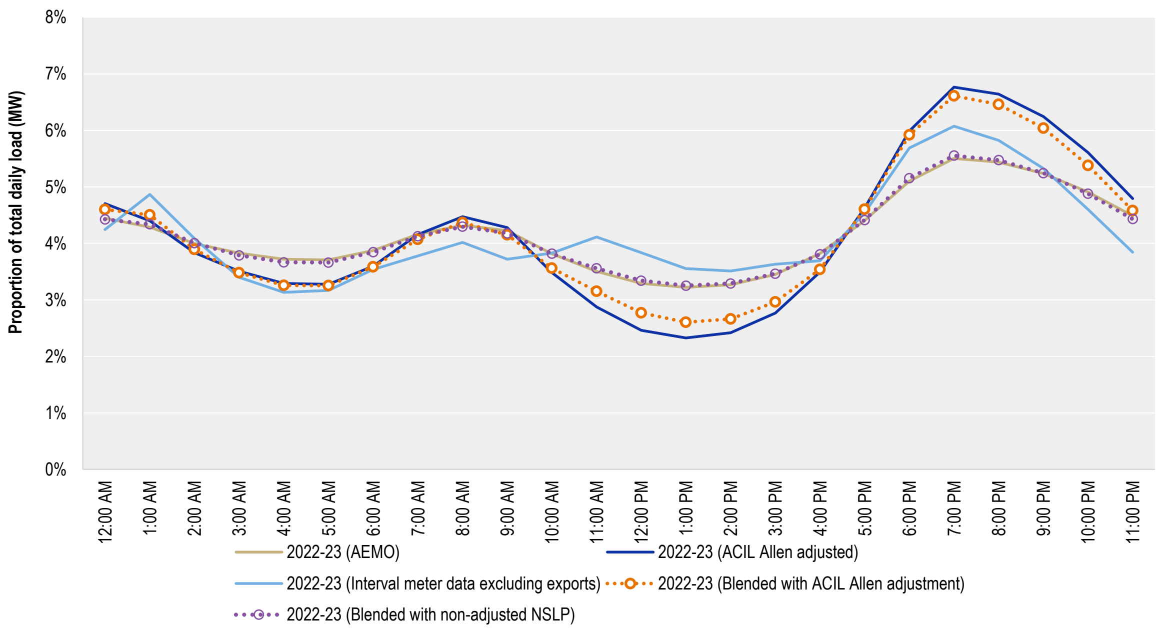
NSW was not impacted by AEMO's interim adjustment. Therefore, we have modelled WEC estimates in NSW regions for DMO 6 (Endeavour Energy, Essential Energy and Ausgrid) using AEMO's non-adjusted NSLP data. This approach is consistent with previous DMO determinations.

Adopting a blended load profile

Both the adjusted and non-adjusted load profiles used to estimate the WECs will be blended with interval meter data in Energex and SAPN. For NSW, the NSLP and interval meter data has also been blended. We consider a blended approach suitable in that it allows the methodology to account for rising installation of interval meters among consumers and will more accurately reflect the load profile overall.

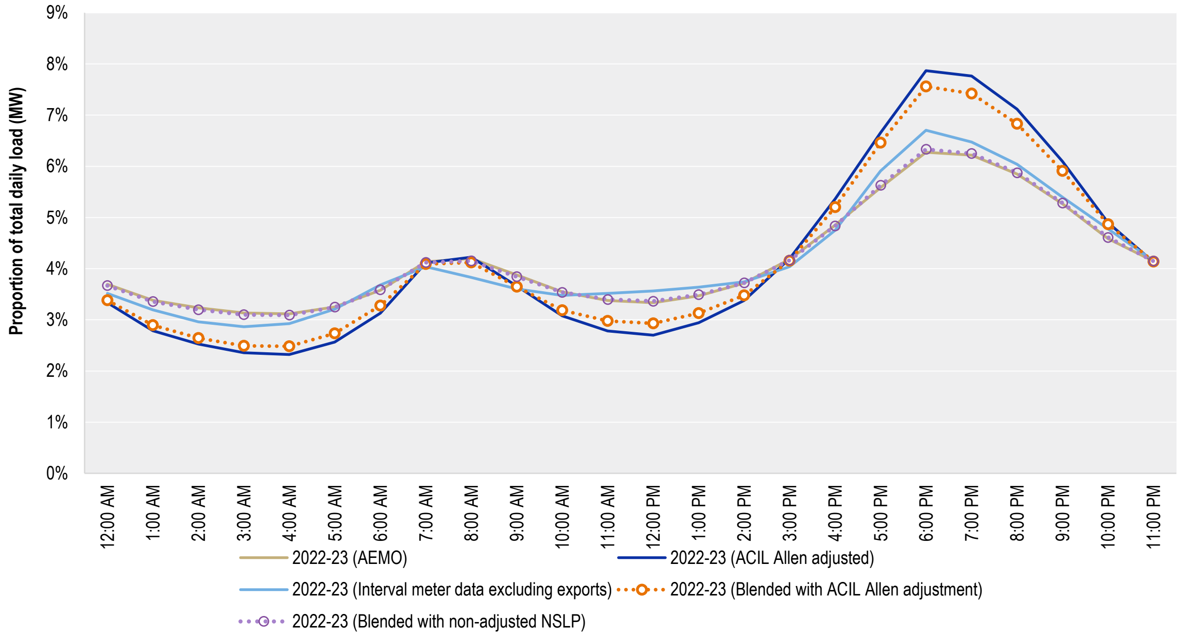
We have not included small customer solar exports in the interval meter dataset that is used to create the blended profile. While this may deviate from the load profile shape a retailer is settled against, we consider that a load profile that includes solar exports overstates the costs of the daytime carve-out for retailers. This is because the inclusion of exports would not account for other customer demand that is satisfied by consumers exporting behind a Transmission Node Identifier. While retailers may face costs for consumer exported energy through a feed-in tariff, these are less than equivalent to the wholesale cost of electricity. We note that the interval meter datasets used to create the blended load profile are flatter than AEMO's NSLP. This is due partly to the dataset containing a greater portion of small business load, which has greater average demand for electricity during the day. The flatness of the interval meter load profile is also due in part to the exclusion of small customer solar exports.

Figure 5.2 SAPN load profile inputs



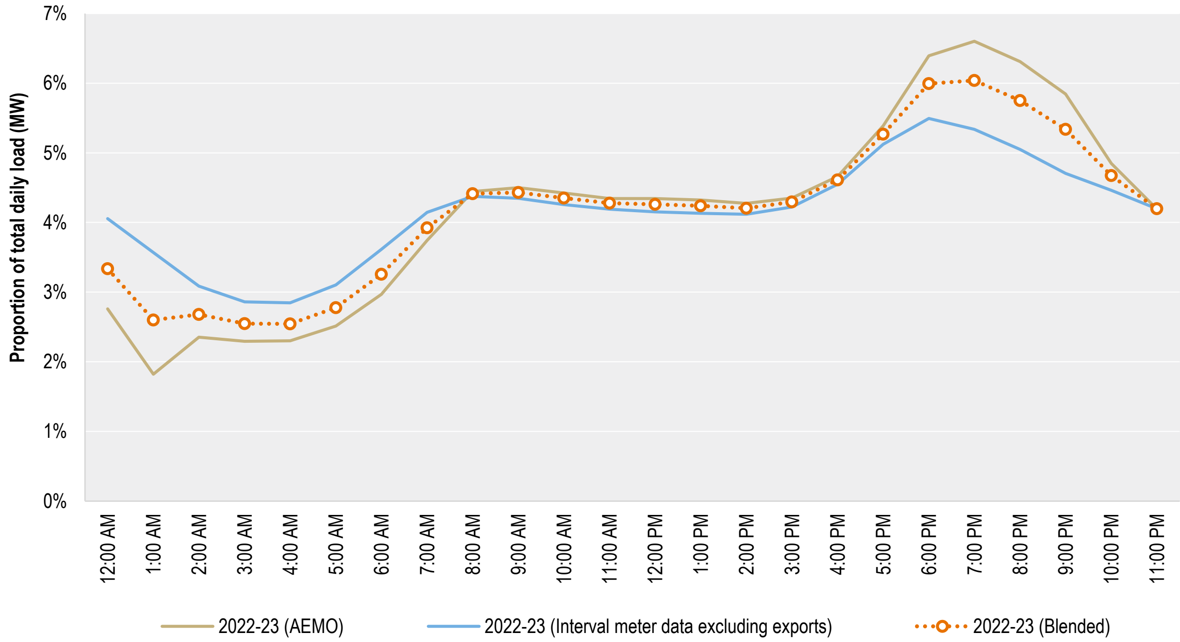
Source: AER analysis using AEMO, ACIL Allen data

Figure 5.3 Energex load profile inputs



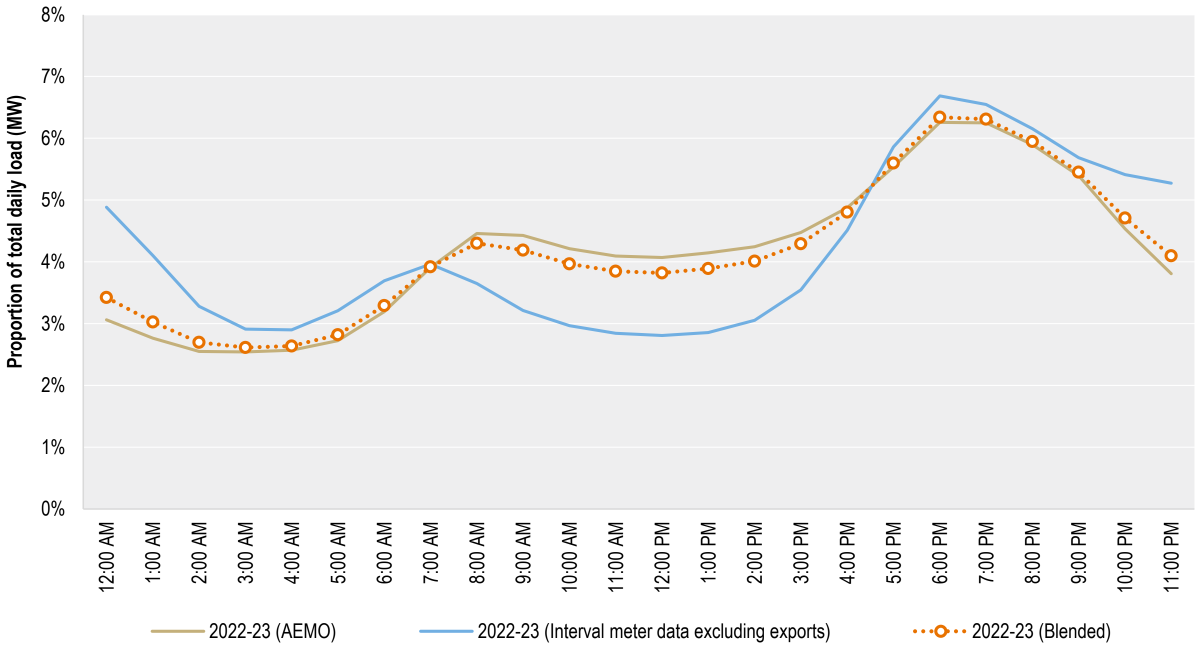
Source: AER analysis using AEMO, ACIL Allen data

Figure 5.4 Ausgrid load profile inputs



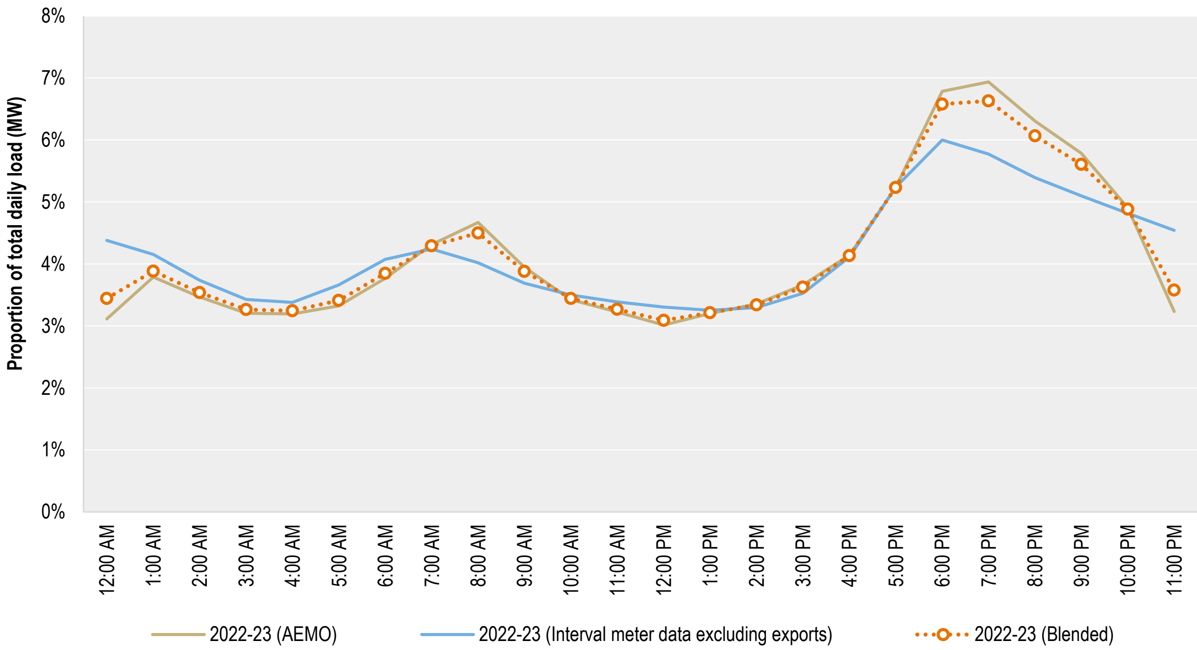
Source: AER analysis using AEMO, ACIL Allen data

Figure 5.5 Endeavour Energy load profile inputs



Source: AER analysis using AEMO, ACIL Allen data

Figure 5.6 Essential Energy load profile inputs



Source: AER analysis using AEMO, ACIL Allen data

We note that submissions from retailers considered that a load profile including exports would be the most representative of the load that they hedge against. However, we are aware of several strategies used by retailers to flatten their respective loads that cannot be accounted for in the wholesale cost methodology. Such load shifting measures can include the use of batteries, demand management, hot water and electric vehicle charging orchestration and other 'solar soaking' strategies.[63] Additionally some contracting products reported via our OTC collection for South Australia, such as load following hedges and contracts that had conditions based on net load positions, highlighted other options that retailers are using that mitigate the impacts of the day time carve-out resulting from solar PV exports.

We consider that accounting for solar exports without comprehensively accounting for strategies used to counter them would result in an over-recovery of costs from consumers for DMO 6. We welcome options and evidence from stakeholders on how the treatment of solar exports could be adjusted considering the likely over-recovery from consumers if exports were to be included in the load profile data.

We are also aware that approximately one-quarter of customers captured under the NSLP in Energex and SAPN regions have solar PV systems, with the exports of those systems being included in the NSLP dataset. Due to the nature of the dataset, we are unable to exclude these exports, but note that they cause a peakier NSLP than would be the case if they were excluded. This issue will reduce over time as the interval meter rollout progresses.[64] We consider it a limitation that we need to accept in the interim period.

Other load profile assumptions

Following feedback from stakeholders supporting a consistent approach, we have decided to maintain:

- a single load profile for residential and small business customers
- separate load profiles for each distribution network in NSW.

We note that residential and small business customers possess different load profiles as expressed in retailer submissions. However, we consider keeping a single load profile for these customer segments and incorporating interval meter data to create a blended profile will ensure we better capture the daytime solar carve-out. This would be more representative of a residential load shape, which is what a majority of stakeholders considered important to reflect.

We note Powershop's query on introducing separate methodologies for customers who have and haven't upgraded to smart meters but recognise this is outside the scope of the legislation underpinning the requirements for the DMO.

For the NSW load profiles, stakeholder responses were mixed and feedback to support a change to a singular profile was limited. We recognise that a singular load profile approach is applied in practice by some retailers but consider a change in approach by adopting a singular profile could result in inadvertently benefiting or burdening customers within a given distribution network. Therefore, we will maintain separate load profiles for each distribution network in NSW. This would also align with our approach to have separate cost-reflective network charges.

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63 Some retailers have demonstrated measures to flatten their load profiles and manage the daytime carve-out of demand resulting from solar PV exports. AGL, FY24 Half-Year Results Presentation, 8 February 2024, p. 19; Origin Energy, FY24 Half Year Results Presentation, 15 February 2024, p. 31.

64 The AEMC recommends a target of universal uptake of smart meters by 2030 in NEM jurisdictions. AEMC, *Final Report – Review of the regulatory framework for metering services*, 30 August 2023, p. i.

5.3.2 South Australian wholesale methodology

Use of confidential contract information

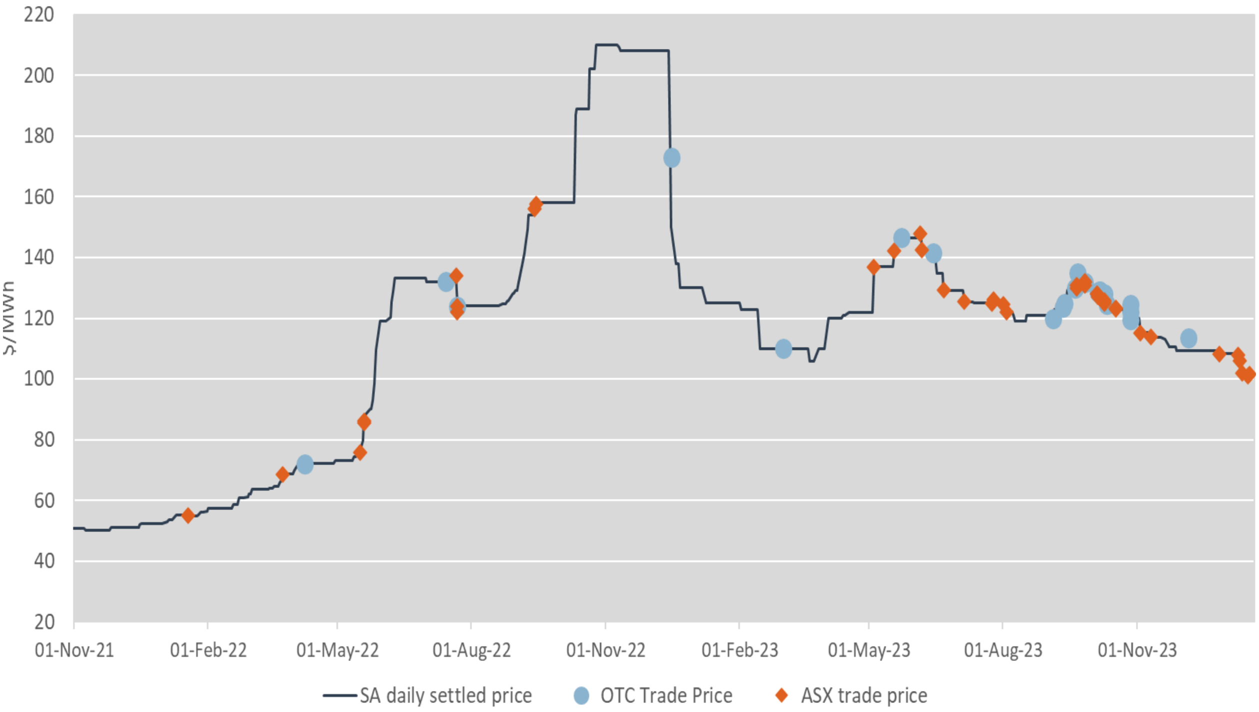
We have maintained the use of ASX data, using base futures (including the volume arising from the exercise of options), caps and the premium for call options for the DMO 6 draft determination. This aligns with our approach for the DMO 5 determination.

As outlined above, to investigate concerns about market liquidity, we sought additional OTC contract market data from retailers. We requested contract information for trades that had occurred over the previous 3 years that was relevant to the DMO 6 period, to assess whether ASX data in isolation was an accurate reflection of the costs a retailer faces.

From the OTC data collected, we analysed how contract products, with like terms to ASX traded products, aligned with ASX prices and volumes. For structured contracts (other than standard base, cap and option contracts), we also compared types of products and respective volumes and prices to improve our understanding of the range of types of contracts retailers use in South Australia.

For OTC contracts with terms aligned with ASX traded contracts, the OTC data provided to the AER by market participants did not suggest a material price difference (Figure 5.7). Participants reported that approximately 320 MW of OTC swaps with terms aligned with ASX contracts were traded for the period to 31 December 2023. This is compared with a total of 366 MW of ASX base futures contracts traded for the DMO 6 period up to 23 February. The confidential contract information also confirmed that base futures (swaps) and caps are still the most used contract types in South Australia.

Figure 5.7 OTC and ASX trade price comparison, South Australia Q3 2024



Source: AER analysis using ASX and OTC Energy data.

Other methodologies considered

Consistent with the majority of stakeholder feedback, the draft determination does not incorporate the use of Victorian contracts or SRAs in modelling wholesale costs for South Australia.

We acknowledge that inter-regional management of an SRA position is difficult because of the non-firm nature of SRAs. Additionally, we did not observe a large number of Victorian futures contracts reported by South Australian participants in our collection of contract data.

We acknowledge that the AEC, Powershop and EnergyAustralia recommended the use of broker curves in response to the question of alternative methodologies that could be used to determine the wholesale cost in South Australia. However, we remain concerned that these sources of data are unlikely to be transparent and representative of market conditions.

Additionally, due to ongoing concerns around liquidity in the South Australian contract market, we requested ACIL Allen undertake an initial long-run marginal cost (LRMC) estimate for South Australia for use as a comparative data point against our current wholesale forecasting methodology.

The LRMC analysis was based on the latest AEMO Integrated System Plan 'Step Change' scenario data, modelling both greenfield (modelling creates generation to meet supply at least cost) and brownfield (modelling based on current generation fleet) options. This was then scaled down to the South Australian load profiles to produce a WEC estimate.

The WEC estimates produced from both scenarios were slightly lower than those resulting from the current wholesale methodology. As the brownfield approach does not capture the up-front capital cost of the current generation fleet, this produced the lowest estimate of all. However, the LRMC estimates were modelled over a longer horizon than the DMO 6 period. The outcomes of the modelling over the longer term highlighted that additional generation would need to be built over the longer term, more than what was needed in financial year 2024–25, to meet forecast demand. Therefore, it is likely the WEC resulting from an LRMC analysis would increase in the following years.

This LRMC analysis, along with OTC data, has provided a helpful datapoint in the context of low contract market liquidity. We will retain our current methodology but will continue to use comparative data sources to assess wholesale costs in South Australia, due to our ongoing concerns with liquidity.

5.3.3 Other wholesale cost issues

75th vs 95th percentile

After considering stakeholder views, we propose to maintain the current approach of using the 75th percentile estimate of modelled cost outcomes.

In DMO 4 and 5, we adopted the 75th percentile estimate of modelled cost outcomes. Across these periods, despite the wholesale market experiencing higher levels of volatility, we still considered that retailers were able to recover their efficient costs of providing their services due to a number of risk-averse assumptions embodied in the DMO methodology.

While we acknowledge that retailers recommended the AER revert to using the 95th percentile estimate of modelled cost outcomes, we consider that the 75th percentile strikes the right balance between retailers recovering their efficient costs of providing their services and the allocation of risks to consumers. In our view, the 95th percentile provides a significant margin of error against underestimation and is likely to result in a wholesale cost estimate that is significantly higher than what a typical retailer would incur, other than in the most extreme circumstances.

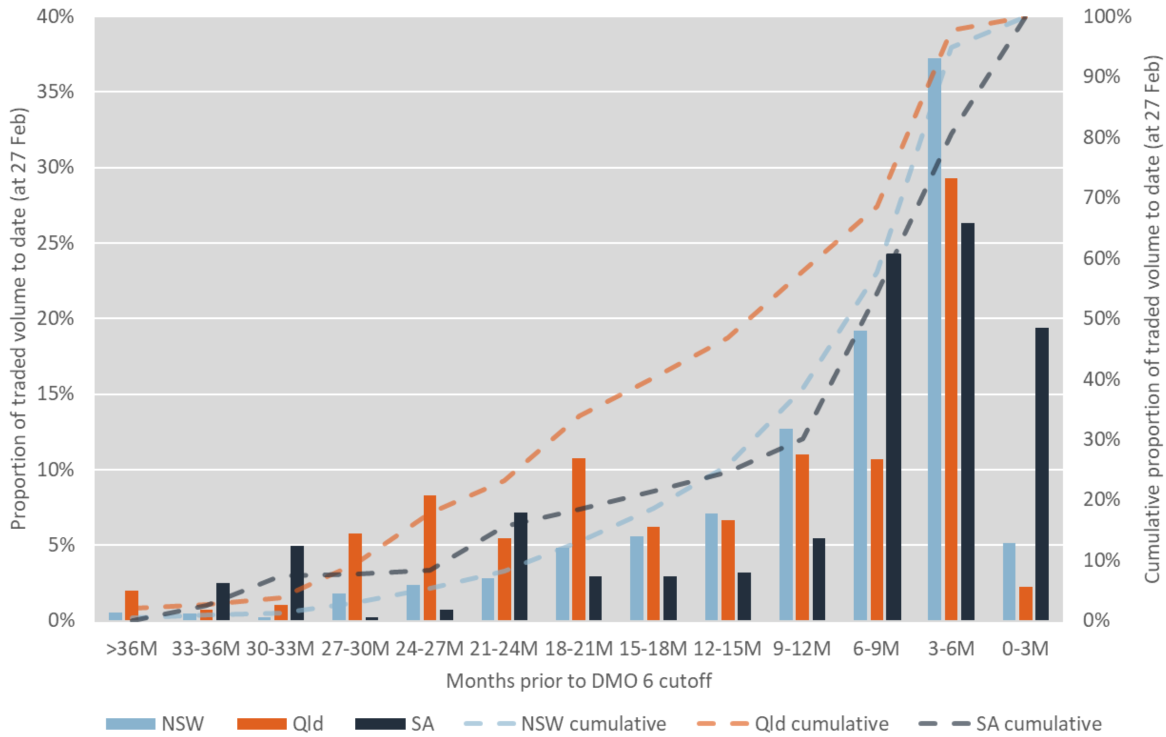
Length of book build period

We have retained the current approach for the hedge book build period, which involves a book build process using all available trades on the ASX. We do not consider that there has been a case for change made.

While hedging strategies will differ across retailers, we consider the current approach that smooths price movements in the DMO best captures all contract price movements for the relevant DMO 6 contracts. As such, the current approach does not favour one type of hedging strategy over another. A longer book build also means that wholesale price changes from year to year are more stable over time, which we consider is appropriate given the purpose of the DMO to provide a fallback price protection for consumers.

A shorter book build as suggested by retailers to better reflect changes in the market would result in greater volatility in the wholesale component of the DMO and prevent any smoothing of unexpected increases or decreases in contract prices. This would result in the significant volatility in the contract market over recent years being reflected immediately in the DMO price and not smoothed over a 2 to 3-year period. Analysis highlights that although there is limited contract trading for DMO 6 future products greater than 30 months prior to the period, trading still does occur and starts to pick up from this period onwards. This is longer than the 12 to 24-month or 12 to 18-month periods stakeholders have advocated for, which we consider validates our methodology to capture all relevant trades for contract products used in the DMO (Figure 5.8).

Figure 5.8 Cumulative proportion of financial year 2024–25 futures volume traded



Source: AER analysis using ASX Energy data

Note: Proportion of total volume traded (as at 27 February 2024). Volumes in the 0–3M tranche will continue to grow as the DMO 6 cutoff is still more than 2 months away. Uses ASX data only.

ASX options

We have retained our treatment of options from previous DMO determinations. This includes volume of base futures traded as a result of the exercise of base strip options at the trade weighted strike price plus the trade weighted average premium attached to all exercised and expired call options. We consider ASX options a valuable indicator of the overall cost of energy, noting that retailers commonly use options as a hedging tool. We acknowledge the preference of Momentum Energy for the assessment of options to be based on an average premium cost calculated at the time of purchase. We do not consider premium costs at the time of purchase to be an accurate reflection of the cost faced by retailers and that a trade weighted average strike price more accurately reflects costs.

Changes to coal and gas caps

The DMO 6 period will reflect recent developments in wholesale coal and gas price control regimes. We did not receive any submissions from stakeholders about our intention to pursue this approach. As a result, the wholesale methodology for DMO 6 will assume that coal price caps in NSW and Queensland will be rescinded at the end of the 2023–24 financial year, while a $12 per GJ cap on the price of gas will remain in place under the new Gas Market Code.

5.3.4 Wholesale energy costs

Wholesale energy costs are forecast to decrease across almost all DMO regions and consumer types between the DMO 5 and DMO 6 periods.

This has been driven by movements in contract prices and the time-of-day shape of load profiles and spot price outcomes. The movements in the future base and cap contract prices for 2024–25 on an annualised and trade weighted basis were:

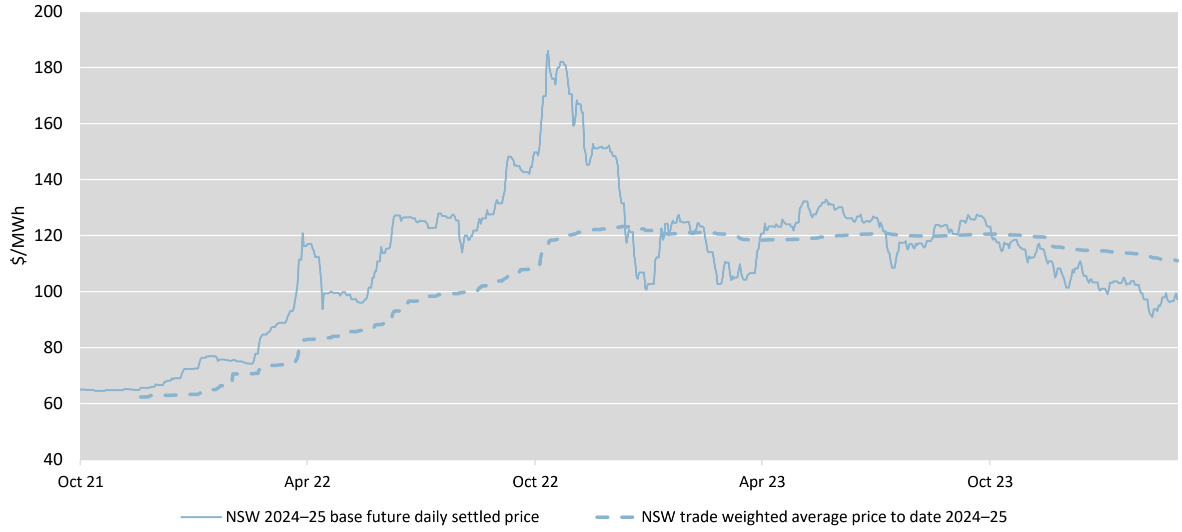
- for NSW – a decrease in base futures contract prices of $10.04/MWh and a decrease in cap contract prices of $1.21/MWh
- for Queensland – decrease in base futures contract prices of $2.65/MWh and an increase in cap contract prices of $0.40/MWh
- for South Australia – a decrease in base futures contract prices of $0.35/MWh and a decrease in cap contract prices of $0.77/MWh.

These contract prices have decreased since the government signalled firm intent to intervene in coal and gas prices in 2022 and remained relatively stable throughout 2023 due to a less volatile year for electricity spot prices. However, the trade-weighted average contract price remains elevated for the 2024–25 period as a result of:

- more expensive contracts that were traded before the government signalled intent to intervene in coal and gas prices
- DMO 6 (financial year 2024–25) futures products remaining at elevated prices across 2023, despite spot market outcomes during that time being lower than anticipated.

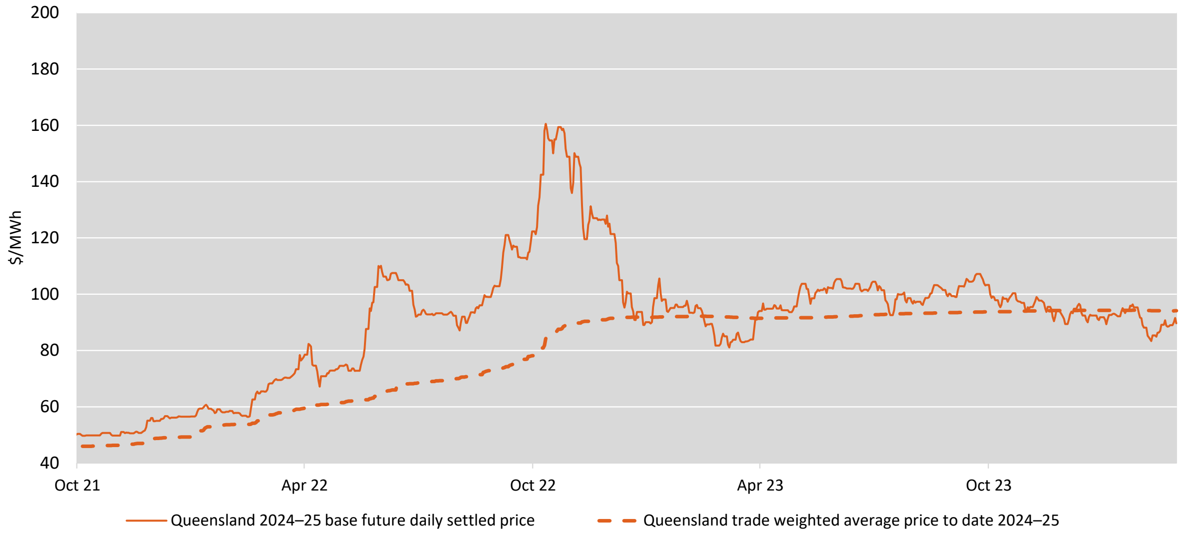
Financial year 2024–25 base future prices peaked in October 2022 before falling sharply in the months that immediately followed. While prices tend to fluctuate month to month, the overall trend during 2023 was relatively stable prices. Prices in all regions fell in the final 3-months of 2023 due to mild weather and low prices in the spot market. This trend continued into 2024 with prices falling further into January and February, most notably in South Australia and NSW (Figures 5.9, 5.10 and 5.11).[65]

Figure 5.9 NSW base future daily settled price and trade weighted average 2024–25



Source: AER analysis using ASX data.

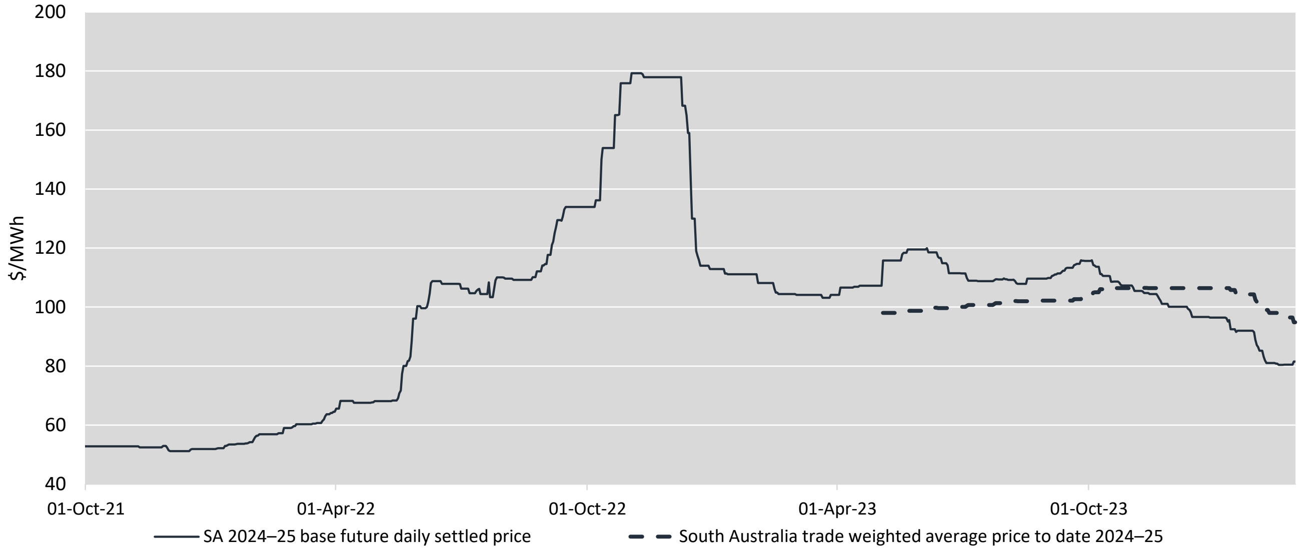
Figure 5.10 Queensland base future daily settled price and trade weighted average 2024–25



Source: AER analysis using ASX data.

65 The annualised trade weighted average price is calculated using all quarters of a given financial year, as a result the trade weighted average line (dotted line) in the below charts only appears after at least 1 MW has been traded for each quarter of the 2024–25 financial year.

Figure 5.11 South Australia base future daily settled price and trade weighted average 2024–25



Source: AER analysis using ASX data.

Wholesale costs continued to experience upward pressure from the peaky shape of regional load profiles. The continued uptake of household solar PV systems reduces effective demand for grid-scale generation during daylight hours. As a result of this low demand, and exacerbated by grid-scale solar generating at the same time, over-hedging can occur, resulting in increased costs due to large contract for difference payments against base contracts.

Conversely, other factors contributed to wholesale cost decreases. This was driven by decreasing contract prices in all regions since DMO 5 and slightly lower costs for several smaller aspects of the WEC, including compensation costs, NEM fees, ancillary services and state-based schemes. In South Australia, these decreases were partially offset by an increase in directions for system security and the South Australian Retailer Energy Productivity Scheme costs.

The draft wholesale costs for DMO 6 are set in Table 5.2, together with the costs used for DMO 5 for comparison.

Table 5.2 Wholesale costs for the 2024–25 DMO 6 draft determination, $/MWh (excl. GST, nominal)

Distribution zone	Customer type	2023–24 (final) ($)	2024–25 (draft) ($)	Change year-on-year (%)
Ausgrid (NSW)	Flat rate	$186.09	$166.53	-10.5%
	CL 1	$111.95	$107.35	-4.1%
	CL 2	$111.70	$107.49	-3.8%
Endeavour Energy (NSW)	Flat rate	$189.50	$177.88	-6.1%
	CL 1	$177.78	$109.57	-38.4%
	CL 2	$177.78	$109.57	-38.4%
	Flat rate	$178.00	$165.48	-7.0%

Distribution zone	Customer type	2023–24 (final) ($)	2024–25 (draft) ($)	Change year-on-year (%)
Essential Energy (NSW)	CL 1	$110.08	$104.51	-5.1%
	CL 2	$110.08	$104.51	-5.1%
Energex (SE Queensland)	Flat rate	$167.03	$165.80	-0.7%
	CL 1	$112.52	$104.96	-6.7%
	CL 2	$119.80	$112.38	-6.2%
SAPN (SA)	Flat rate	$226.13	$183.97	-18.6%
	CL 1	$110.75	$123.05	11.1%

Note: CL refers to controlled load.
Source: ACIL Allen

6 Environmental costs

6.1 Issues paper

In the issues paper we proposed to continue using our market-based approach to forecast environmental costs, with updates for any new and amended schemes. We consider it reasonable to retain our methodology, noting that the submissions to our DMO 5 draft determination generally supported retaining the environmental cost forecasting methodology.

6.2 Stakeholder views

Most submissions did not discuss or raise any issues with the approach we proposed in the issues paper. Only PIAC/ACOSS/SACOSS's joint submission and SACOSS's separate submission commented on environmental cost forecasting and Renewable Energy Target (RET) costs.

These submissions recommended a re-evaluation of the DMO with the scope to consider how environmental costs can be removed from the cost stack of bills and instead recovered through government revenue and taxation to ensure vulnerable consumers are not carrying a disproportionate burden of transition costs.[66]

SACOSS's submission considered energy costs to be regressive, with low-income households paying a larger proportion of their income on energy compared with average income households, and that including the cost of these schemes in energy bills has inequitable impacts. Furthermore, SACOSS reasoned there is no incentive for industry to change its behaviour by procuring more electricity from renewable sources or improving customer energy efficiency if the costs of the RET scheme are fully recovered from customers. Also, it argued that premium feed-in-tariff schemes are no longer required to incentivise the uptake of solar PV in South Australia, and low-income households and renters unable to access solar should not disproportionately bear the cost of these schemes.[67]

We acknowledge PIAC/ACOSS/SACOSS and SACOSS's concerns relating to the recovery of environmental costs. However, under the Competition and Consumer (Industry Code—Electricity Retail) Regulation 2019, one of the AER's roles is to determine the cost of complying with the laws of the Commonwealth and the relevant state or territory in relation to supplying electricity in the region.[68]

The RET is an Australian Government scheme[69] designed to reduce emissions of greenhouse gases in the electricity sector and encourage the additional generation of electricity from sustainable and renewable sources. Similarly, the distributor feed-in tariff of 44 c/kWh will remain in place until 30 June 2028 for eligible solar systems[70] unless changes

66 PIAC/ACOSS/SACOSS, joint *Submission to DMO 6 issues paper*, 9 November 2023, p. 3; SACOSS, *Submission to DMO 6 issues paper*, 8 November 2023, p. 16.

67 SACOSS, *Submission to DMO 6 issues paper*, 8 November 2023, p. 16.

68 Regulations, s. 16(4)(c)(iii).

69 See Part 2, Division 1, s. 8 of the Clean Energy Regulator, *Renewable Energy (Electricity) Act 2000* for an overview of the RET scheme.

70 Only available for eligible solar PV systems connected to the grid before 30 September 2011, see the South Australian Government website page on solar feed-in payments for more details (accessed 22 February 2024).

are made to the legislation underpinning the scheme.[71] Distributors are required to credit these customers under this South Australian legislation,[72] and in turn recover these credits through network tariffs charged to retailers. We are required to include network costs in the DMO price.[73] Therefore, we consider that state/territory and Australian Government policymakers are best placed to consider how to address the issues raised by PIAC/ACOSS/SACOSS and SACOSS.

6.3 Draft determination

Having considered stakeholder submissions and the available information on environmental costs, we consider it appropriate for the DMO price to include these costs and we propose to retain our market-based approach to environmental cost forecasting.

6.3.1 Environmental cost inputs

The environmental cost inputs for 2024–25 are outlined in Table 6.1, together with inputs used for 2023–24 for comparison.

Table 6.1 Environmental costs for 2023–24 and 2024–25 (excl. GST, nominal)

Distribution region	Tariff	2023–24 $/MWh	2024–25 $/MWh	Change year-on-year (%)
Ausgrid (NSW)	Flat rate	18.68	19.38	3.7%
	CL 1	18.71	19.44	3.9%
	CL 2	18.71	19.44	3.9%
Endeavour (NSW)	Flat rate	18.80	19.55	4.0%
	CL 1	18.80	19.55	4.0%
	CL 2	18.80	19.55	4.0%
Essential (NSW)	Flat rate	18.48	19.07	3.2%
	CL 1	18.48	19.07	3.2%
	CL 2	18.48	19.07	3.2%
Energex (SE Queensland)	Flat rate	15.26	15.88	4.1%
	CL 1	15.26	15.88	4.1%
	CL 2	15.26	15.88	4.1%
SAPN (SA)	Flat rate	19.33	21.43	10.9%
	CL 1	19.33	21.43	10.9%

Note: CL refers to controlled load. The values in this chart are total environmental costs which are made up of variable costs for Large-scale Renewable Energy Target, Small-scale Renewable Energy Scheme, Energy Savings Scheme (New South Wales), Peak Demand Reduction Scheme (NSW) and losses.
Source: ACIL Allen, *Default market offer 2024–25 draft determination technical report.*

71 *Electricity Act* 1996 (SA), s. 36AE(8).

72 *Electricity Act* 1996 (SA), s. 36AE(1).

73 In determining DMO prices, the AER must have regard to cost of distributing and transmitting electricity in the region, Regulations, s. 16(4)(c)(ii).

7 Retail costs

We employ a 'cost-stack' methodology in our approach for setting retail costs. This approach meets the DMO objectives and provides greater transparency by determining the various retail costs individually, and consistency in pricing between regions.

The retailer costs include:

Costs to serve – such as costs for billing, call centres, debt collection and hardship programs. We refer to the ACCC Electricity Inquiry cost data to estimate costs to serve, which we escalate by CPI to the end of the DMO year.

Costs to acquire/retain customers – e.g. loyalty programs or advertising campaigns informing customers of their options, rights and obligations. We refer to ACCC Electricity Inquiry data for these costs (and escalate them by CPI to the end of the DMO year.)

Smart meter costs – retailers are responsible for managing their smart meter installation and maintenance costs. We seek this smart meter cost data from retailers directly through information requests.

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

We consider that the above 'cost-stack' methodology remains appropriate for the DMO 6 determination with:

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74 ACCC, *Inquiry into the National Electricity Market report – December 2023 Report*.

- updated cost calculations from the ACCC (which is made up of reported data from Tier 1 retailers and a number of smaller retailers in total representing 84% of residential and 81% of small business customers)
- our own information requests to retailers (representing 93% of residential and 91% of small business customers). These retailer requests are undertaken because the ACCC does not collect information on smart metering costs.

Retailers make up-front investments, which depreciate over time. We do not separately determine depreciation and amortisation of costs, but instead set a retail allowance that includes an efficient margin informed by EBITDA.

7.1 Issues paper

7.1.1 Bad and doubtful debt

Bad and doubtful debts are the retailer costs incurred and written off as unpaid bills. A retailer's debt is made up of:

- unbilled (accrued) revenue earnt but not yet billed
- customer debt earnt and billed
- an estimated provision for customer debt (based on a retailer's subjective assessment of expected non-payment).

Retailers set aside revenue to cover such costs.

In the DMO 5 final determination bad and doubtful debt costs were calculated at $26 and $16.06 per small customer, respectively.

Prior to the DMO 5 final determination we considered the weighted average of bad and doubtful debt data from 3 publicly listed retailers (AGL, Origin Energy and Red Energy and Lumo Energy). During the DMO 5 consultation, stakeholders recommended the AER request debt information from the ACCC and base the allowance for bad and doubtful debt in the DMO prices off this information.[75] The ACCC considers bad debt costs (which includes doubtful debts) separately from 'retail and other' costs within its cost stack data.

Bad and doubtful debt cost data was not publicly available before the ACCC's Inquiry into the National Electricity Market report 2023. While the ACCC had historically collected this information, it has never been published. As noted in the DMO 5 final determination, the ACCC shared the unpublished data with the AER for DMO 5 (subject to retailer confidentiality being maintained).

The issues paper proposed to continue the updated approach of using the allowance figures for residential and small business based on the weighted average of the actual bad and doubtful debt data, pending the availability of the ACCC Electricity Inquiry cost data.

7.1.2 Small business costs

Our previous methodology for calculating small business costs involved converting the variable retail costs (cents per kilowatt hour (kWh)) published by the ACCC so that they can be applied on a dollars per customer basis. Historically, we have used the average low-

75 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.

voltage non-residential annual usage amount reported by distributed network service providers (DNSPs) to convert the ACCC c/kWh figure into dollars per customer.

During DMO 5, stakeholders had encouraged the AER to make improvements in this process – namely, obtain the actual dollar amount per small business customer retail and other cost data from the ACCC (or directly from retailers through a data request) and incorporate this data directly into our calculation. At the time of the DMO 5 final determination, the ACCC maintained a preference for reporting on a cents per kilowatt (c/kWh) basis due to a varied distribution of usages across this group.

The issues paper proposed to continue engaging the ACCC to develop its reporting to improve our small business costs methodology. As of December, the ACCC Electricity Inquiry cost data now reports its retail and other cost data on a dollars per small business customer basis.

7.1.3 Smart metering costs

Smart meter costs are the annual costs retailers incur for smart meters and include costs associated for installation, maintenance and IT costs. These costs need to be included in the DMO price to ensure the outturn price retailers face reflects the DMO regulations, which require the AER to consider the cost of complying with laws to supply electricity in the region.

The issues paper discussed the anticipated increased smart meter costs stemming from the AEMC's installation acceleration target period commencing in July 2025 (pending completion of the rule change process). The AEMC's final report[76] proposed DNSPs develop plans to retire their fleet of legacy meters (known as legacy meter retirement plans) by 2030. Under that retirement plan framework, each DNSP would be required to develop a 5-year schedule (with yearly interim targets) to retire its fleet. The AEMC also recommended that up-front fees for metering installations be banned.

Based on the retail performance reporting since the commencement of smart meter reporting (specifically Q4 2023 data), in Figure 7.1 we have outlined a historic trend analysis of the rate of installations (June 2019 to December 2023). The rate of installations has increased more significantly since 2021, particularly for South Australia.

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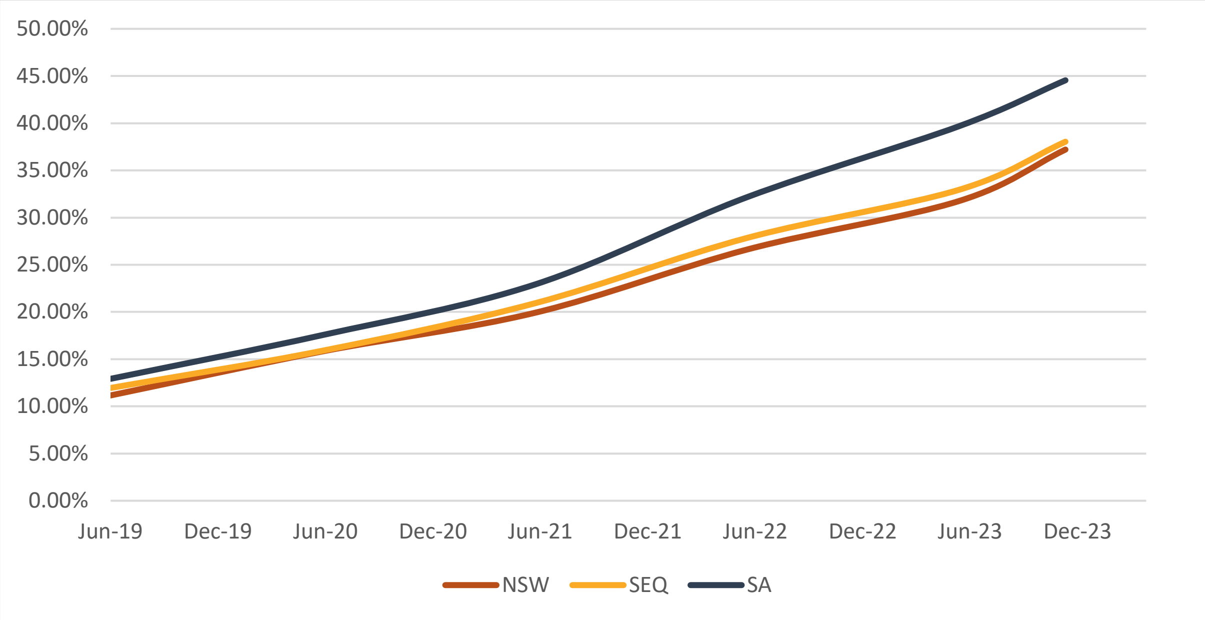
76 AEMC, *Final Report – Review of the regulatory framework for metering services*, 30 August 2023, p. i.

Figure 7.1 Proportion of smart meter installations – June 2019 to Dec 2023



We anticipate the need for a significant increase in the rate of retailer installations due to the acceleration target and 5-year schedule period. The issues paper proposed that because of this anticipated installation rate increase the costs of smart meters will certainly increase when the 5-year rollout schedule commences in 2025. With this in mind, we sought stakeholder insight and evidence of what relevant cash flow impacts can be expected (that is, operational and capital expenditure) and how such costs should be included in the DMO price.

We also sought stakeholder feedback on whether to use historic or forecast smart meter installations to estimate costs, whether to factor up-front fees in the smart meter allowance and whether such costs should be subject to independent audit or review.

7.2 Stakeholder views

Fourteen stakeholders submitted feedback on issues relating to retailer costs and smart meters.

7.2.1 Bad and doubtful debt

The majority of retailer submissions noted support for the AER continuing to use the ACCC Electricity Inquiry cost data).[77]

EnergyAustralia, who supported the AER using the more accurate ACCC data, also noted the likelihood of bad and doubtful debt costs materially increasing in subsequent years. Such increases would more likely be reflected in the DMO 6 price using the ACCC data.[78]

In their submission, Energy Locals encouraged the AER to seek a broader representative sample of retailers beyond those represented in the ACCC dataset. They argued that smaller retailers who are not included in this dataset are at risk because the current methodology

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77 Simply Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 3; EnergyAustralia, *Submission to DMO 6 issues paper,* 3 November 2023, p. 9; AGL, *Submission to DMO 6 issues paper,* 10 November 2023, p.3; Origin, *Submission to DMO 6 issues paper,* 10 November 2023, p. 8;Alinta Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 6; Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 5.

78 EnergyAustralia, *Submission to DMO 6 issues paper,* 3 November 2023, p. 9.

focuses on data of large retailers, who are arguably less exposed to bad debts because they have a larger, more stable customer base than that of a smaller retailer.[79] We disagree with this position, noting that the ACCC dataset sample is made up of a broad group (reflecting the costs retailers (of varied sizes) representing 84% of residential and 81% of small business customers). We maintain the view that this ACCC dataset is currently the most accurate single figure representative sample available to base our calculations on in the DMO model. However, in future DMO periods we intend to collect this data directly from a broader sample of retailers.

Energy Consumers Australia (ECA) suggested that bad and doubtful debt is not relevant to standing offer customers because customers on hardship programs should be on market offers.[80] The DMO serves a dual purpose of protecting consumers and effectively regulating competitive markets, so the retailer costs we determine are based on all customers (not just those on standing offers).

7.2.2 Smart metering costs

Historic versus projected

Retailers (except Origin Energy) favoured a forecasting approach for calculating smart meter costs over the use of historic data.[81] EnergyAustralia submitted that their project costs for the accelerated smart meter rollout are substantial and the extent to which the acceleration has increased should be reflected in the current DMO approach through a projected approach.[82] Alinta Energy built on this support by recommending that the AER seek specific forecast installation plans from retailers for DMO 6 (in addition to any historic counts) as part of a voluntary request.[83]

The AEC supported a forecasting approach and suggested that an inevitable increased uptake will result in a greater shortfall in the DMO price, and the lag for the full recovery in a subsequent DMO will impact retailers if a projected approach is not pursued.[84]

However, Powershop suggested that a review of the methodology is required to establish a more accurate forecast of ongoing retailer costs and remove biases related to efficiencies based on economies of scales.[85]

Origin Energy supported using historic installations. They noted that under current methodology there is a lag in recovery of smart meter costs, which will bring financial exposure for retailers with accelerated rollout. Given the DMO regulations do not allow for true-up mechanisms (DMO prices must be set for the actual year), moving to a supported projection of rollout in DMO 6 would likely result in over-recovery from forecasting errors.[86]

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79 Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 6.

80 ECA, *Submission to DMO 6 issues paper,* 31 October 2023, p. 2.

81 Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 2; AEC, *Submission to DMO 6 issues paper,* 3 November 2023, p. 4; Powershop, *Submission to DMO 6 issues paper,* 3 November 2023, p. 5; AGL, *Submission to DMO 6 issues paper,* 10 November 2023, pp. 3-4; EnergyAustralia, *Submission to DMO 6 issues paper,* 3 November 2023, p. 7; Simply Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 4.

82 EnergyAustralia, *Submission to DMO 6 issues paper,* 3 November 2023, p. 7.

83 Alinta Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 3.

84 AEC, *Submission to DMO 6 issues paper,* 3 November 2023, p. 4.

85 Powershop, *Submission to DMO 6 issues paper,* 3 November 2023, p. 5.

86 Origin, *Submission to DMO 6 issues paper,* 10 November 2023, p. 16.

The South Australian Department for Energy and Mining also support this existing approach. They noted that there will be several reasons why a retailer will not reach the expected installation rates, or exceed them, and it would be prudent to only base costs on those already incurred.[87]

Several retailers noted that if we did not move to a projection approach, the AER should add a cost of capital to cover the difference between historic installs and installs that occur during DMO 6.[88] Otherwise, retailers suffer a material financial disadvantage. We acknowledge this point and note that these concerns should be somewhat mitigated by a further round of information requests to update our smart meter rollout data closer to the final determination.

Any forecast given by retailers for DMO 6 would not be binding. Furthermore, there is no assurance that all retailers have commenced forecasted installation plans. However, for DMO 7, we expect that the legacy meter retirement plans could form a suitable basis for a forecast approach (subject to the necessary rule changes being finalised). We will consider this approach again in DMO 7.

In DMO 5, PIAC, AGL and 1st Energy raised concerns about the calculation of smart meter costs in the cost build-up methodology, citing a need for more transparency on how retailers incur and recover their costs. Only PIAC (submitting with ACOSS and SACOSS) has retained that position for DMO 6.[89] As noted in the DMO 5 final determination, we remain satisfied that retailers face significant costs relating to smart meters and there is a real risk of the DMO determination failing to reflect reasonable costs if these are not included in the DMO price.

Up-front fees

An up-front smart meter costs is any fee that retailers charge as part of a market or standing offer (such as a connection fee). The approach introduced in DMO 5 involved subtracting these costs from the smart meter allowance component.

The AEC and Origin Energy's feedback from the issues paper noted that the approach from DMO 5 disadvantages retailers that do not charge up-front fees for smart meter installations.[90] We acknowledge this argument and agree there is a risk it could incentivise retailers charging up-front fees, which would run counter to the AEMC's recommendations that up-front charging of metering costs cease.

Independent audit/review

Submissions received from Energy Locals, Powershop and AGL encouraged the AER to seek an independent audit of retailers' reported metering costs.[91] 1st Energy suggested the AER consider future planning to ensure the audit/review considers unexpected costs retailers are burdened with, such as the cost of complex multi-phase installations as well as related high regional travel costs.[92] Energy Locals specifically highlighted the varied range of

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87 SA Department for Energy and Mining, *Submission to DMO 6 issues paper,* 10 November 2023, p. 4.

88 Alinta Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 6; Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 6; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper,* 9 November 2023, p. 5.

89 PIAC/SACOSS/ACOSS, *Submission to DMO 6 issues paper,* 9 November 2023, p. 5.

90 AEC, *Submission to DMO 6 Issues Paper,* 3 November 2023, p.3; Origin, *Submission to DMO 6 issues paper,* 10 November 2023, pp. 16-17.

91 Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 78; AGL, *Submission to DMO 6 issues paper,* 10 November 2023, p. 4; Powershop, *Submission to DMO 6 issues paper,* 3 November 2023, p. 6.

92 1st Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 4.

installation costs retailers face across different jurisdictions.[93] AGL suggested the AER engage directly with retailers on this individually to determine appropriate audit/review requirements, parameters and a suitable structure or process.[94]

Simply Energy proposed the AER obtain advice from an independent consultant familiar with the metering industry, as an alternative approach to a burdensome retailer audit.[95] We acknowledge the burdensome nature of an audit/review for retailers and recognise the various challenges retailers face with metering costs. Consequently, we consider it is prudent for the AER to fully understand and verify the accuracy of these costs.

Given the time and planning required for an independent audit/review of metering costs and impending metering rule changes, we will work on this in preparation for DMO 7.

7.3 Draft determination

As foreshadowed in the issues paper, to estimate the relevant retail costs in DMO 6 we will use the following data:

- smart meter installation and costs data provided by retailers
- ACCC 'retail and other costs' set out in Appendix C to the ACCC's Report[96], which includes retail and other costs, costs to acquire and retain customers, and doubtful debt, which the ACCC considers to be a foregone or negative revenue amount, as opposed to a true cost incurred.

These 'retail and other costs' have been in decline in previous years[97] – which the ACCC attributes to supporting the position of retail competition effectively delivering benefits to consumers.[98]

Retail and other costs and costs to acquire and retain allow retailers selling to a majority of customers to achieve a reasonable profit.[99] The ACCC noted in their report that Tier 1 retailers have maintained a significant cost advantage over smaller retailers in both the costs to serve and costs to acquire and retain.[100]

7.3.1 Bad and doubtful debt

We intend to use allowance figures for residential and small business based on the weighted average of the actual data now published in the National Electricity Market report 2023. We consider this more granular data to be a more representative sample than the publicly sourced data used in the previous approach. As noted above in section 7.1, the ACCC considers and reports bad debt costs (which includes doubtful debts) separately from 'retail and other' costs within Appendix C of the ACCC's report.

The ACCC observed NEM-wide increases in bad debt costs, as set out in Appendix C of the ACCC's report, which rose by $9 per residential customer and $18 per small business

93 Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 6.

94 AGL, *Submission to DMO 6 issues paper,* 10 November 2023, p. 4.

95 Simply Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 4.

96 ACCC, *Inquiry National Electricity Market, December 2023 Report*, Appendix C.

97 ACCC, *Inquiry National Electricity Market, December 2023 Report*, Appendix C, Supplementary table C8.1b.

98 ACCC, *Inquiry National Electricity Market, December 2023 report,* p. 37.

99 ACCC, *Inquiry National Electricity Market, December 2023 Report*, Appendix C, Supplementary table C8.6a, Supplementary table C8.8a.

100 ACCC, *Inquiry National Electricity Market, December 2023 Report*, p. 37.

customer in 2022–23 (in real terms) [101]. The ACCC suggests these increases in cost could be driven by legacy effects of the COVID-19 pandemic and the current economic outlook putting financial pressures on households. We have also observed consumers impacted by such pressures with the number of residential customers on retailer hardship programs (in DMO regions) increasing by 43.2% over the past 12 months (NSW by 49%, SE Queensland by 48.6% and South Australia by 22.9%).[102]

All macro-economic factors such as interest rates levels, inflation and unemployment rates are factored by retailers in their assessment of bad and doubtful debt costs.

The increased granularity of the ACCC's disaggregated data means we can now consider bad and doubtful debt costs on a state-by-state basis, rather than taking one national figure. Table 7.1 outlines the difference in costs from DMO 5 and DMO 6 using a state-based cost value, as well as the overall increase in these costs.

Table 7.1 Estimated costs due to bad and doubtful debts in DMO 6

Distribution region	Customer type	DMO 5 BDD cost p/customer ($pa)	DMO 6 BDD cost p/customer ($pa) (proposed)	Year-on-year difference ($)
Ausgrid	Residential with and w/o CL	$19	$30	$11
	Small Business w/o CL	$40	$65	$25
Endeavour	Residential with and w/o CL	$19	$30	$11
	Small Business w/o CL	$40	$65	$25
Essential	Residential with and w/o CL	$19	$30	$11
	Small Business w/o CL	$40	$65	$25
Energex	Residential with and w/o CL	$19	$24	$5
	Small Business w/o CL	$29	$42	$13
SAPN	Residential with and w/o CL	$29	$40	$11
	Small Business w/o CL	$32	$52	$20

Note: DMO 6 model numbers are based on the DMO 5 NEM numbers.

We were conscious to ensure the costs from the updated approach, while a more representative sample for retailers, aligned with our objective to protect consumers from unreasonable prices. Using the disaggregated state-based data provides greater insight into the difference in cost faced by retailers across the DMO regions.

101 ACCC, *Inquiry National Electricity Market, December 2023 report*, p. 37.

102 AER, *Schedule 4 – Retail Performance Data Q2 2023–24*, Sheet: 'Hardship Numbers'.

While all regions are experiencing increases, the impact of using a state-based versus a NEM-wide calculation is mixed between regions and customer types, with some better or worse off depending on the level of aggregation.

Table 7.2 Increase comparison

Distribution Region	Customer Type	Increase for DMO 6 (State based)	Increase for DMO 6 (NEM based)
Energex	Residential	$5.00	$9.83
	Small business	$13.00	$20.00
SAPN	Residential	$11.00	$9.83
	Small business	$20.00	$20.00
Endeavour/Essential /Ausgrid	Residential	$11.00	$9.83
	Small business	$25.00	$20.00

The approach also reduces the cross subsidisation across regions that has happened in prior DMOs when an average is applied.

Based on stakeholder support for using more specific and representative ACCC data, we have decided to calculate bad and doubtful debt on a state-by-state basis for each region.

7.3.2 Smart metering costs

Our retailer data request issued in November 2023 sought:

- the number of customers by meter and tariff type
- smart meter costs
- any one-off or up-front fees charged for installation
- whether the costs are inclusive or exclusive of the costs incurred that are then recovered by charging that particular customer an up-front fee.

Furthermore, we sought installation projections from retailers for the DMO 6 period. A group of 10 retailers responded to this request (representing 93% of residential customers and 91% of small business customers in DMO regions). This is a larger group than those responding to the same request in DMO 5.

Up-front fees

In response to our smart meter requests issued in November 2023, 3 retailers provided data accounting for up-front fees (compared with 2 retailers who provided this data in DMO 5). These fees amounted to around $3.46 per residential customer and $10.58 per small business customer.

We propose to change our DMO 5 approach and now include up-front installation fees in our smart meter allowance calculation. We know that the majority of retailers are not charging up-front installation fees. While we acknowledge that the small group of retailers continuing to apply these fees may over-recover during DMO 6, we are confident that this will not be the case in DMO 7. Based on current industry practices shown from these requests, and feedback from retailers on our issues paper, we are confident that the risk of overcharging customers due to these up-front fees is minimal.

Including the up-front fees in the DMO reduces the incentive for more retailers to add on these fees. This updated approach is aligned with the recent AEMC reform recommending up-front fees be prohibited. Once this happens, the issue of over or under-recovery from including fees in the calculation will no longer be a concern in future DMO periods.

The new approach would result in $0.46 to $3.58 increases in the smart meter allowance, depending on customer type and region.

Historic versus projected

We propose to continue the current approach of using historic installation data until the legacy meter retirement plans are in place. While only a small group of stakeholders supported this approach[103], we consider this will be more accurate than current forecasting. However, we will ask retailers to update their metering rollout data before the final DMO 6 determination to ensure our inputs are as current as possible.

We are also proposing to include an estimate for a cost for capital to cover the shortfall between actual installation numbers captured in our data and projected installations still to occur during the DMO 6 year.[104] The estimate amount calculated for cost of capital (excl. GST) ranges from $0.50 (Ausgrid) to $0.98 (Endeavour) for residential, and $0.45 (Ausgrid) to $0.72 (Energex) for small business. See Tables 7.4, 7.5 and 7.6 for more details.

Smart meter costs for DMO 6 are set out in Tables 7.2 and 7.3. Appendix B also sets out a detailed breakdown of our calculation of smart meter costs.

Table 7.3 Average residential smart meter cost, per distribution region

Distribution zone	Average annual cost per smart meter (ex GST)	Average annual cost per customer (ex GST)
Ausgrid	$110.14	$25.97
Endeavour	$107.05	$35.29
Essential	$121.01	$33.54
Energex	$109.51	$33.34
SAPN	$104.19	$35.34

Table 7.4 Average small business smart meter cost, per distribution region

Distribution zone	Average annual cost per smart meter (ex GST)	Average annual cost per customer (ex GST)
Ausgrid	$123.40	$23.43
Endeavour	$122.41	$23.55
Essential	$119.99	$24.39

103 Origin Energy, *Submission to DMO 6 Issues Paper,* 10 November 2023, p. 16; SA Department for Energy and Mining, *Submission to DMO 6 Issues Paper,* 10 November 2023, p. 4.

Energex	$122.04	$30.54
SAPN	$126.54	$28.39

7.4 Summary of determinations for retail costs

Table 7. to 7.6 set out the components for our cost build-up approach in DMO 6.

Table 7.5 Residential without controlled load retail costs (excluding GST)

Distribution zone	Retail and other costs sourced from ACCC Inquiry	Smart meter costs	Bad and doubtful debt costs	Capital Allowance (smart meters)	Forecast CPI adjustment	Total	Difference to DMO 5 (%)
Ausgrid	$142.00	$25.97	$30.00	$0.50	$12.91	$211.38	10.2%
Endeavour Energy	$142.00	$35.29	$30.00	$0.98	$13.54	$221.81	12.7%
Essential Energy	$142.00	$33.54	$30.00	$0.86	$13.42	$219.82	14.1%
Energex	$142.00	$33.34	$24.00	$0.79	$13.01	$213.14	12.0%
SAPN	$146.00	$35.34	$40.00	$0.83	$14.45	$236.62	20.2%

Table 7.6 Residential with controlled load retail costs (excluding GST)

Distribution zone	Retail and other costs sourced from ACCC Inquiry	Smart meter costs	Bad and doubtful debt costs	Capital Allowance (smart meters)	Forecast CPI adjustment	Total	Difference to DMO 5 (%)
Ausgrid	$142.00	$25.97	$30.00	$0.50	$12.91	$211.38	10.2%
Endeavour Energy	$142.00	$35.29	$30.00	$0.98	$13.54	$221.81	12.7%
Essential Energy	$142.00	$33.54	$30.00	$0.86	$13.42	$219.82	14.1%
Energex	$142.00	$33.34	$24.00	$0.79	$13.01	$213.14	12.0%
SAPN	$146.00	$35.34	$40.00	$0.83	$14.45	$236.62	20.2%

Table 7.7 Small business retail costs (excluding GST)

Distribution zone	Retail and other costs sourced from ACCC Inquiry	Smart meter costs	Bad and doubtful debt costs	Capital Allowance (smart meters)	Forecast CPI adjustment	Total	Difference to DMO 5 (%)
Ausgrid	$183.00	$23.43	$65.00	$0.45	$17.68	$289.56	21.3%
Endeavour Energy	$183.00	$23.55	$65.00	$0.65	$17.70	$289.90	21.7%
Essential Energy	$183.00	$24.39	$65.00	$0.62	$17.75	$290.76	29.7%
Energex	$183.00	$30.54	$42.00	$0.72	$16.66	$272.92	32.8%
SAPN	$183.00	$28.39	$52.00	$0.67	$17.17	$281.23	27.6%

8 Retail margin and competition allowance

The Regulations direct that in determining a reasonable per customer annual price we are to have regard to the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity. The DMO price has also been set such that it meets and appropriately balances the policy objectives to:

- 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
- maintain incentives for competition, innovation and investment by retailers, and incentives for consumers to engage in the market.

For DMO 4 and 5 we included a retail allowance in the DMO price to meet these objectives.

The retail allowance was set to reflect a return on retailer risk, allow for differences in retailers' costs and provide room for competition. We also consider it desirable that DMO prices include a similar level of allowance regardless of DMO region.

8.1 Issues paper

8.1.1 Retail allowance approach to best balance DMO objectives

The issues paper noted an inherent tension existing between the objectives – a higher retail allowance in the DMO price 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 reduces to a point where new entrant retailers cannot compete.

Our role is to determine a retail allowance that appropriately balances these issues. In determining the appropriate balance, the AER must have regard to the matters listed in the Regulations and may have regard to any matters the AER considers relevant.[105]

In the issues paper we sought stakeholder views on whether the retail allowance approach should:

- remain as a percentage of the DMO price – this would mean the retail allowance would increase/decrease in dollar terms if wholesale, network environmental and/or retail costs increase/decrease from year to year
- change to a fixed dollar amount – this would mean the retail allowance would be set at a dollar amount and indexed with CPI to preserve its real value
- be cast as separate components of efficient margin (percentage based) and a fixed competition allowance (dollar amount) – this approach envisaged calculating an efficient margin in a similar way to the approaches used by OTTER, ICRC and ESC in their regulatory decisions. The additional competition allowance could be determined

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105 Regulations, 2019, s. 16(4)(a), (b), (c)(iv), (c)(v) and 16(4)(d).

according to retail cost data provided by large and small retailers to the ACCC or some other data source.

8.1.2 Retail margin

The issues paper noted that other economic regulators have determined that margins ranging from 5% (OTTER) to 5.3% (ESC and ICRC) of total price are appropriate for regulated electricity prices. These margin proportions can also be expressed as 5.3% and 5.6% of costs, respectively.[106]

The issues paper also noted that, 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 14 electricity retailers selling to 84% of residential customers and 81% of small business customers in the NEM.[107] 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 2.3% of total costs in 2022–23, but with some significant variation in trends and magnitude of margins across regions and customer types.[108] We hold different views of how relevant self-reported margins are to our DMO purpose, and have conducted our own analysis using the same information and produced different results.

The issues paper sought stakeholder feedback on how a separate efficient margin should be calculated.

8.1.3 Competition allowance

The issues paper acknowledged the role of the retail allowance in accommodating differences in retailers' costs and providing room for competition. Larger retailers may have achieved economies of scale, allowing fixed costs to be spread over a broader customer base and reducing their costs on a per customer basis. However, smaller retailers or newer entrants who may not enjoy this same benefit bring value to customers through the competitive tension they bring to 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.

The issues paper considered how determining a competition allowance based on the observed ranges in retailers' per-customer costs to serve would mean the competition allowance would reflect variations in costs faced by retailers. It would also allow retailers with higher costs to serve to still achieve an efficient margin.

The issues paper sought stakeholder feedback on how we should calculate this separate competition allowance.

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106 ICRC is proposing a retail margin approach that uses a 50/50 mix of fixed dollar amount and a percentage of cost stack in its draft report for 2024–27, ICRC, *Retail electricity price investigation 2024–27*, January 2024, p. 47; OTTER used a percentage method until 2022–23, when it instead adopted a fixed $ amount (based on indexing the previous percentage-derived margin in dollar terms with CPI) until 2024–25, OTTER, *2022 Standing offer electricity pricing investigation final report, April 2022*, p. 33.

107 ACCC, *Inquiry into the National Electricity Market*, *December 2023 Report*, p. 116.

108 Since publishing our issues paper, the ACCC has released its December 2023 report covering the 2022–23 financial year. ACCC, *Inquiry into the National Electricity Market*, *December 2023 Report*, p. 4.

8.2 Stakeholder views

8.2.1 Retail allowance approach to best balance DMO objectives

In response to the question of how the retail allowance can balance the DMO objectives, most retailers supported continuing the approach used in DMO 5, whereas governments and consumer representatives suggested a change in the approach was needed to better protect consumers.

Percentage or dollar amount for retail allowance

In response to the question of whether the retail allowance should be a percentage or fixed dollar amount, most retailers and the AEC did not support a fixed amount.[109] In their submission Origin Energy argued that a fixed dollar retail allowance would create the risk that if the DMO increased, the retail allowance would decrease in relative terms, and that this would have a negative impact on the level of discount offered by retailers and likely result in a reduction in competition.[110] Powershop and AGL said that a change away from the percentage methodology is not warranted – both retailers emphasised the value of regulatory certainty.[111] The AEC argued that a fixed dollar amount may not adjust for changing market conditions and would need regular re-evaluations to ensure it remained appropriate.[112] One retailer, Energy Locals, did support changing to a fixed dollar amount; they considered that this would de-link the retail allowance from movements in the other DMO price elements and this would give certainty to retailers.[113]

In contrast to most retailer views, the NSW Energy Minister's view was that the retail allowance should be a fixed amount indexed with CPI, advocating that this would ensure that volatility in the other cost elements would not be compounded by the methodology for the retail allowance.[114] The South Australian Department for Energy and Mining also supported changing to a fixed dollar amount. They argued that given cost-of-living increases and the increase in DMO 5 prices that customers did not need incentives to shop around, and that the AER should focus the DMO on the objective to protect consumers.[115]

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109 AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 5; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 4–5; Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7; EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 2, 14–15; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, p. 4; Powershop and Shell Energy, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 6–7.

110 Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 14-15.

111 AGL, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 4–5; Powershop and Shell Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 6.

112 AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 5.

113 Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 7.

114 The Hon Penny Sharpe MLC, *Submission to the issues paper*, 8 November 2023, p. 1.

115 SA Department for Energy and Mining, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 2–3.

Separating the margin from the competition allowance

Retailer and AEC submissions did not support the AER changing the retail allowance into separate components.[116] Retailers considered that the approach used in DMO 5 met the DMO objectives. Alinta Energy considered that a methodology change posed a risk to retailers and creates regulatory uncertainty.[117] Powershop were concerned that separating the two components may not factor in other components of innovation and investments to compete and innovate. The AEC did not consider there is a case for changing the approach, and that separating the components could exceed the current retail allowance approach.[118]

Retailers Alinta Energy and Energy Locals also had additional views. Alinta Energy proposed that the AER should set a maximum percentage differential between individual retailers' standing and market offer prices. Energy Locals argued that having single retail allowance rates favours Tier 1 retailers because those large retailers can spread fixed costs across a much larger customer base, and this results in higher barriers to entry and less competition from new entrant retailers.

Consumer groups supported the AER identifying efficient margin and competition allowance arguing it provided greater transparency.[119] The combined submission from PIAC, SACOSS and ACOSS recommended separating into efficient margin and any additional allowance applied in the DMO should be clearly labelled as 'competition/innovation headroom' allowing decision-makers and consumers to clearly understand and quantify the additional 'cost of competition' in the DMO.[120] SACOSS argued that the DMO should be a 'fair' price.[121] The Queensland Energy Minister advocated for a reduction in the retail allowance, arguing that competition in Victoria is robust and competitive despite the VDO not including an additional headroom allowance.[122]

Other submissions were less definitive in their position about splitting the allowance into a margin and competition component. The Australian Energy Minister, the Hon. Chris Bowen MP, requested that the AER take broader economic conditions into account, and encouraged the AER to use the flexibility afforded by the Regulations to consider any other matters we consider relevant.[123] The Customer Consultative Group joint submission did not recommend determining a competition allowance with regards to the costs of a new entrant into the retail market because they considered the costs of market entry would vary depending on the model of the business and the target segment.[124]

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116 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; AEC, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 5–6; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 4–5; Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 3, 7; GloBird, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Momentum, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2; Simply Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Powershop and Shell Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, p. 4.

117 Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7.

118 AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 5.

119 Customer Consultative Group, *Joint submission to DMO 6 issues paper,* 1 November 2023, p. 2.

120 PIAC/ACOSS/SACOSS, *Submission to DMO 6 issues paper*, 9 November 2023, p. 10.

121 SACOSS, *Submission to DMO 6 issues paper*, 8 November 2023 pp. 2–3, 15.

122 The Hon Mick de Brenni MP, Submission to DMO 6 issues paper, 5 March 2024, pp. 1–2.

123 The Hon Chris Bowen MP, *Submission to the issues paper*, undated, p. 1.

124 Customer Consultative Group, *Joint submission to DMO 6 issues paper,* 1 November 2023, p. 2.

8.2.2 Retail margin

We also received a range of views on how a separate margin should be calculated. Retailers considered that the retail margin should be a percentage, because it needs to move relative to retailer risk.[125] In contrast, the NSW Energy Minister held concerns that a percentage approach would exacerbate price increases,[126] and Energy Locals supported a fixed dollar retail margin as it would give retailers greater certainty.[127] Energy Consumers Australia considered that the 'efficient margin' approach that Essential Services Commission of Victoria uses for the Victorian Default Offer (VDO) margin to be suitable for the DMO as it is sufficient for competition to occur.[128] EnergyAustralia also supported an efficient margin approach.[129]

Retailers supported separate retail margins for residential and small business customers, arguing this would appropriately reflect different risk and market characteristics.[130]

In contrast, consumer groups did not support different margins for residential and small business customers. Submissions considered the higher retail allowances for small businesses to be arbitrary, noting that a higher proportion of small business customers are on standing offers capped at the DMO price, and cited surveys that small business customers are experiencing increasing concerns regarding electricity affordability.[131]

8.2.3 Competition allowance

EnergyAustralia's qualified support for an efficient retail margin was on the proviso that the additional competition allowance included allowances to incentivise competition and investment and to capture depreciation and amortisation. Alinta Energy did not support a separate competition allowance calculation because they considered it was likely to be highly subjective without reliable benchmarks to calculate with any confidence.[132] Powershop considered that the competition allowance could be similar to the allowances applied by the QCA and Independent Pricing and Regulatory Tribunal which would be around 5% of total costs.[133] Similarly, the AEC also thought that the combined margin and competition allowance would be 10% or greater.[134]

The Customer Consultative Group was concerned that including a competition allowance on top of retailer costs to operate that include advertising costs would be a doubling of

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125 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 4–5; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2, 14–15.

126 The Hon Penny Sharpe MLC, *Submission to the issues paper*, 8 November 2023, p. 1;

127 Energy Locals, *Submission to DMO 6 issues paper, 3 November 2023,* p. 7.

128 Energy Consumers Association, *Submission to DMO 6 issues paper*, 31 October 2023, p. 2.

129 EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7.

130 1st Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 5; EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, pp. 4–5; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2; Energy Locals, *Submission to DMO 6 issues paper, 3 November 2023,* p. 8; Simply Energy, *Submission to DMO 6 issues paper,* 3 November 2023, p. 5.

131 Energy Consumers Association, *Submission to DMO 6 issues paper*, 31 October 2023, pp. 2–3; SACOSS, *Submission to DMO 6 issues paper*, 8 November 2023 p. 10; Customer Consultative Group, *Joint submission to DMO 6 issues paper,* 1 November 2023, p. 2; Business Council SA, *Submission to DMO 6 issues paper*, 1 November 2023, pp. 1–3.

132 Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3.

133 Powershop and Shell Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7.

134 AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 5.

competition costs – this requires clear explanation of the costs and allowances included in the DMO price.

8.3 Draft determination

8.3.1 Retail allowance approach to best balance DMO objectives

Our decision is to split the retail allowance into separate retail margin and competition allowance components.

As set out in section 3.3 above, the AER makes its determination in accordance with section 16 of the Regulations. Section 16(4) of the Regulations require us to consider a range of specific factors in determining a reasonable annual price. Most relevant to retail allowance, these include retail costs, costs to acquire, retain and serve customers, the principle that a retailer should be able to make a reasonable profit and other matters we consider relevant. As we discussed, we note submissions received that increased inflation, cost of living pressures and electricity affordability are matters that the AER should take into account. Under section 16(4)(d) of the Regulations, in making our decision, we have taken these matters into account in making our draft determination.

The retail margin will be set as a percentage of the DMO price excluding the competition allowance. The competition allowance will be set as a dollar figure. It will be set such that it recognises the potentially higher costs of new entrant or smaller retailers entering the market and providing competitive tension. We will calculate the competition allowance based on the statistical spread in retailer costs derived from reported data and will also consider broader economic conditions in setting this allowance.

This change in methodology will introduce more transparency in setting DMO prices. We consider this approach best achieves the DMO objectives to incentivise competition as it more directly ties the DMO price to competition objectives of allowing a variety of retailers with different costs to compete and achieve a reasonable profit. It also provides a clear framework through which we will consider the economic conditions facing electricity consumers and the electricity market in each DMO process.

8.3.2 Retail margin

Our decision is to set the retail margin component as an efficient margin.

We have determined the efficient margin is:

- 6% of residential DMO prices excluding the competition allowance
- 11% of small business DMO prices excluding the competition allowance.

This will allow retailers selling to the vast majority of customers to achieve at least the efficient margin in the DMO price.

In competitive markets, suppliers of goods and services generally receive a margin that is commensurate with the level of risk associated with that industry (relative to systemic economy-wide risk).

This is because:

- If margins are lower than the level of risk, firms and investors providing capital will exit the market, as the capital deployed would receive a greater risk-adjusted return elsewhere.

- If margins are higher than the level of risk, then a competitor or new entrant will be prepared to offer prices with a lower margin. Firms with higher margins will then lose customers to this competitor.

The Regulations direct that in determining a reasonable per customer annual price we are to have regard to the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity.[135] When considering a reasonable margin in relation to supplying electricity, we must therefore have regard to the relevant risks that retailers face, and not consider risks that have been otherwise managed through other components of the DMO cost stack. Without seeking to quantify individual risks, we have taken this into account in our determination of margin.

Given this link to risk, we consider that it is appropriate for the margin to be set as a percentage instead of a fixed dollar amount, as risks scale with underlying costs. This can be expressed as either a percentage of price or a percentage on cost. Treating the retail margin as a percentage of the DMO price (excluding the competition allowance) is consistent with approaches among other economic regulators and we have expressed it in this way throughout this draft determination.

We do note the NSW Minister's submission concern that a percentage approach exacerbates price increases. However, we consider this issue is mitigated when adopting an approach which separates margin from competition allowance and uses a smaller percentage efficient margin and competition allowance based on a dollar amount.

As we have never attempted to quantify an efficient margin before, we have undertaken analysis in DMO 6 to test alternative methods. We have estimated possible EBITDA margins under different approaches below in the following sections being:

- inferring margins from advertised offers available between 1 July 2023 and 31 August 2023 by backing out DMO 5 costs
- inferring margins within the ACCC's findings of the actual retail prices charged to customers on 1 August 2023 by backing out DMO 5 costs
- assessing historic trends in individual retailers' achieved EBITDA margins and incurred costs reported to the ACCC as part of its retail electricity market inquiry
- benchmarking retail margin determinations in other jurisdictions.

We engaged ACIL Allen to assist with this work including assessing the relative merits of the methodologies and conducting the analysis based on advertised offers.

Inferring margins from prices of advertised offers

ACIL Allen inferred prices and EBITDA margins for each DMO region and customer type by examining residential, residential with controlled load and small business fixed rate market offers available between 1 July and 31 August 2023 and backing out DMO 5 retail, wholesale, environmental and network costs. Offers were excluded if they were targeted to new customers on the basis these could be loss leading or 'acquisition offers'.[136]

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[135] Regulations, s. 16(4)(b).

[136] See chapter 5 of ACIL Allen's report for a more detailed description of its approach, ACIL Allen, *Default Market Offer 2024–25 methodologies for estimating the retail allowance and estimated values,* February 2024, p. 49–55.

This approach is a relevant consideration for an efficient margin. It is the price retailers are willing to charge and the margin retailers are willing to receive in a competitive market. This approach also has the key the benefit of netting out any over- or under-estimates in the retail margin due to under- or over-estimates of underlying costs.

ACIL Allen found competitive retail prices offered from 1 July to 31 August 2023 had average retail margins of 0.7% to 4.2% for residential customers without controlled load, 1.5% to 5% for residential customers with controlled load, and margins of 10.7% to 16.0% for small business customers.[137]

AER analysis of ACCC retail pricing information

In its December 2023 report the ACCC examined the average retail prices customers were being charged on 1 August 2023 by collecting large amounts of plan level pricing data from retailers representing a sample of over 5 million customers in NSW, Victoria, SE Queensland and SA.

Importantly, this analysis examines the prices customers were actually charged on 1 August 2023, which is different to traditional analysis that focuses on the ‘snapshot’ of market offers available for a given time period. This means this analysis includes a mix of prices of current market offers as well as market offers that had closed (that is, were not available to new customers).

This addresses concerns that analysis focusing solely on all currently advertised market offers would underestimate prices all customers pay (and aggregate margins achieved by retailers) as currently advertised market offers tend to be lower priced than expired market offers in order to entice new customers. Customers on closed market offers tend to pay higher prices than customers regularly shopping around for the cheapest price.[138]

In order to compare this data to the DMO price, the ACCC converted every plan’s retail price to an annual cost based on the DMO usage amount. The ACCC then developed customer weighted average prices based on the DMO usage amount in each state for residential flat rate, residential flat rate with controlled load, and small business flat rate customers.

Because these average prices are based on the DMO usage amount, we have subtracted the DMO 5 costs from these average prices to infer our estimate of customer-weighted average EBITDA margin (as a percentage of total bill) available for retailers that have average DMO costs. We have set out these margins in tables 8.1, 8.2 and 8.3 below.

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137 ACIL Allen, *Default Market Offer 2024—25 methodologies for estimating the retail allowance and estimated values,* February 2024, Table 6.1, p. 57.

138 ACCC found a strong correlation between higher prices and large conditional discounts. Customers on these offers have likely been on them for multiple years. Large conditional discounts that exceed a reasonable estimate of the costs that would be incurred by the customer failing to meet the condition were prohibited for new contracts entered into after 1 July 2020, see. ACCC, *Inquiry into the National Electricity Market*, *December 2023 Report*, section 3.4, p. 60–64; ACCC, *Inquiry into the National Electricity Market*, *December 2023 Report*, supp. table C9.14 finds newer plans were 3 to 15% cheaper than older market plans.

Table 8.1 Residential without controlled load, AER estimate of EBITDA margins subtracting DMO costs from ACCC annual prices 1 August 2023

Region	EBITDA if all conditional discounts achieved (%)	EBITDA if no conditional discounts achieved (%)	EBITDA estimate based on conditional discount achievement rates (%)
NSW	6.4	8.5	6.6
SE Queensland	5.9	7.8	6.1
SA	1.3	2.9	1.4

Source: AER analysis of ACCC December 2023 report, appendix C, Supplementary tables C10.1, C9.1, DMO 2023–24 final determination. Note: In its June 2023 report the ACCC found 9% of residential customers failed to achieve their conditional discounts, ACCC, *Inquiry into the National Electricity Market, June 2023 report*, p.61 and Appendix E supp. table A5.3.

Table 8.2 Residential with controlled load, AER estimate of EBITDA margins subtracting DMO costs from ACCC annual prices 1 August 2023

Region	EBITDA% if all conditional discounts achieved (%)	EBITDA% if no conditional discounts achieved (%)	EBITDA estimate based on conditional discount achievement rates (%)
NSW	9.1	11.6	9.4
SE Queensland	8.2	14.6	8.5
SA	7.6	11.3	8.2

Source: AER analysis of ACCC December 2023 report, appendix C, Supplementary tables C10.1, C9.1, DMO 2023–24 Final Determination. Note: In its June 2023 report the ACCC found 9% of residential customers failed to achieve their conditional discounts, ACCC, *Inquiry into the National Electricity Market, June 2023 report*, p.61 and Appendix E supp. A5.3.

Table 8.3 Small business, AER estimate of EBITDA margins subtracting DMO costs from ACCC annual prices 1 August 2023

Region	EBITDA% if all conditional discounts achieved	EBITDA% if no conditional discounts achieved	EBITDA estimate based on conditional discount achievement rates (%)
NSW	6.8	7.4	6.9
SE Queensland	6.6	7.2	6.7
SA	6.5	6.8	6.6

Source: AER analysis of ACCC December 2023 report, appendix C, Supplementary tables C11.1, C11.2, DMO 2023–24 Final Determination. Note: In its June 2023 report the ACCC found 15% of small business customers failed to achieve their conditional discounts, ACCC, *Inquiry into the National Electricity Market, June 2023 report*, p.61 and Appendix E supp. A11.2.

This measure of estimated EBITDA margin is a relevant consideration when determining an efficient margin. This is because it reflects the margins retailers operating in a competitive environment are achieving across all market offer customers, including both engaged customers that switch to acquisition offers, and disengaged customers on closed market offers that return a greater margin.

This is a similar approach to the ACIL Allen analysis outlined above in that it subtracts DMO 5 costs from market offers to estimate EBITDA margins. It has the same benefit in netting out any errors in costs and margin when applied to a DMO cost stack using the same cost methodology.

ACCC EBITDA analysis

We have examined the range of EBITDA margins among retailers reporting to the ACCC as part of its electricity market inquiry covering each financial year across 2018–19 to 2022–23. We consider this information is a relevant consideration to determine an efficient margin as it reflects the actual achieved margins of retailers[139] in competitive markets accounting for a large majority of market share in DMO regions.

However, we regard this information as less applicable as these underlying costs will differ from the underlying costs in the DMO cost stack, meaning that the EBITDA margin percentage will not be applicable in the DMO price. Similarly, the EBITDA margin, when expressed as a dollar figure cannot be easily translated to a DMO cost stack value due to different average electricity consumptions in the ACCC dataset and DMO price.

Benchmarking regulatory decisions in other jurisdictions

We have also had regard to recent decisions from other regulators. These regulators have requirements to determine efficient and/or fair margins. ESC, ICRC and OTTER determine margins for small customers whereas QCA's approach allows separate residential and small business margins to be determined. This information is a relevant consideration when determining an efficient margin in DMO prices.

These margins range from 4.8% (OTTER) to 7.06% (QCA) for residential customers, and from 4.8% (OTTER) to 15.31% (QCA) for small business customers. The retail market characteristics of each jurisdiction and regulator treatment of costs, and retail margin determinations are discussed in ACIL Allen's report.[140]

There are limitations in comparing regulator decisions on efficient margins, similar to those when comparing the actual achieved EBITDA of retailers discussed in the previous section. Each regulator's efficient margin decision will depend on how other costs are determined. If there is more (or less) conservatism in estimating wholesale costs relative to the DMO methodology, then the margin should be less (or more) to account for the different wholesale price risks in each regulator's decision.

Summary of margin analysis

We have considered the sources of information above, giving most weight to our estimate of margins in ACCC customer weighted average prices on 1 August 2023 published by the ACCC and ACIL Allen's analysis of margins inferred from advertised prices. These approaches use the same costs as DMO 5 and are based on the same annual usage amount as the DMO.

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139 The number of retailers considered varied year to year as some retailers were excluded from the analysis in the years they returned negative EBITDA margins.

140 See, ACIL Allen, *Default Market Offer 2024–25 Methodologies for estimating the retail allowance and estimated values*, p. 30.

This analysis found:

- ACIL Allen's average market offer had lower margins than our estimate of margins in ACCC customer weighted average prices for residential flat rate plans
- ACIL Allen average market offer had higher margins than our estimate of margins in ACCC customer weighted average prices for small business customers

These differences are due to the scope of market offers considered in each data source. ACIL Allen has inferred margins from advertised market offers, whereas the ACCC has obtained retailers' plan level pricing data.

There are also considerable ranges in margins across regions and between residential customers with and without controlled load across these two data sources. The separate margins under both approaches are set out in Tables 8.4 and 8.4 and Figures 8.1 and 8.2 below.

We have derived consistent aggregate margins for residential and small business DMO prices by taking the customer number weighted average of the ten separate residential margins and the five separate small business margins. This results in:

- aggregate residential margins of 2.8 (ACIL Allen inferred margins) and 7.2% (our estimate of margins in ACCC customer-weighted average prices)
- aggregate small business margins of 6.8 (our estimate of margins in ACCC customer-weighted average prices) and 13.6% (ACIL Allen inferred margins)

We consider these ranges to be lower and upper bounds for efficient margins.

Our draft determination uses a consistent efficient margin of 6% for residential customers and 11% for small business customers across all DMO regions. These margins reflect some conservatism as they are above the midpoints between the lower and upper bounds of estimates of efficient margins (4.9% and 10.2%).

This addresses concerns of interregional inequity, while recognising the different risks and observed margins achieved for residential and small business segments.

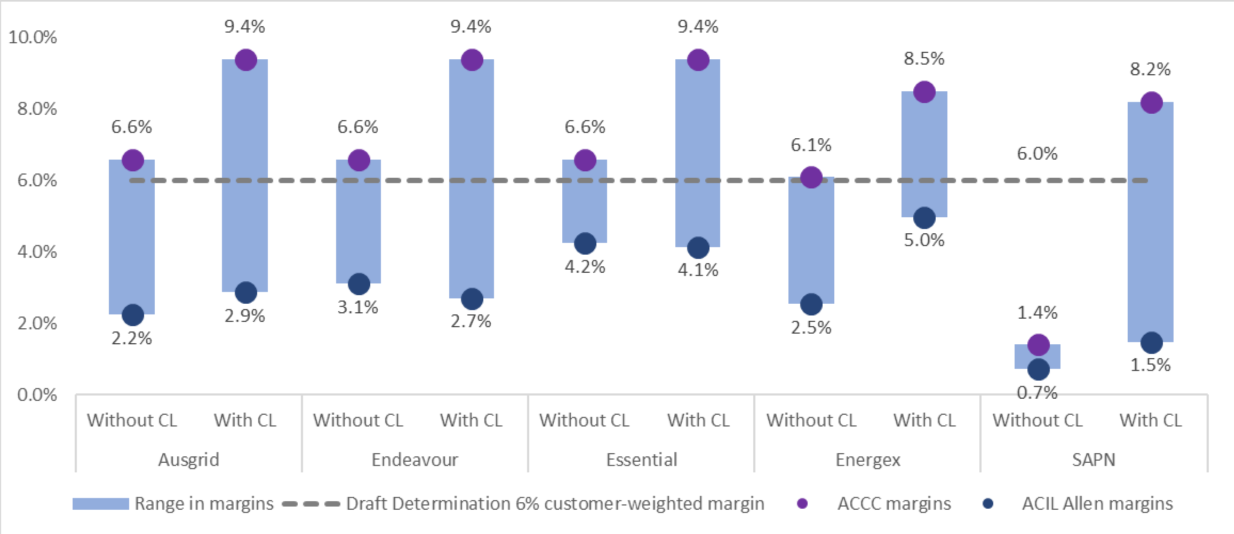
The resulting small business margin of 11% is 5 percentage points higher than residential margin. We note stakeholders concerns regarding higher small business margins, but consider this approach appropriate. This higher margin relative to the residential margin accords with:

- our prior analysis that serving small business customers present comes at greater risk to retailers[141]
- the higher ACIL Allen margins
- our estimate of margins in ACCC customer weighted average annual prices
- EBITDA margins published by the ACCC for small business customers
- the prior differential between residential and small business retail allowances in DMO 4 and 5.

141 See AER, *Default market offer prices 2022–23 Final Determination,* May 2022, p. 45. Average small business debts are approximately 2.5 times greater than residential average debts, AER, *Annual Retail Report 2022–23,* Figures 3.2 and 3.6.

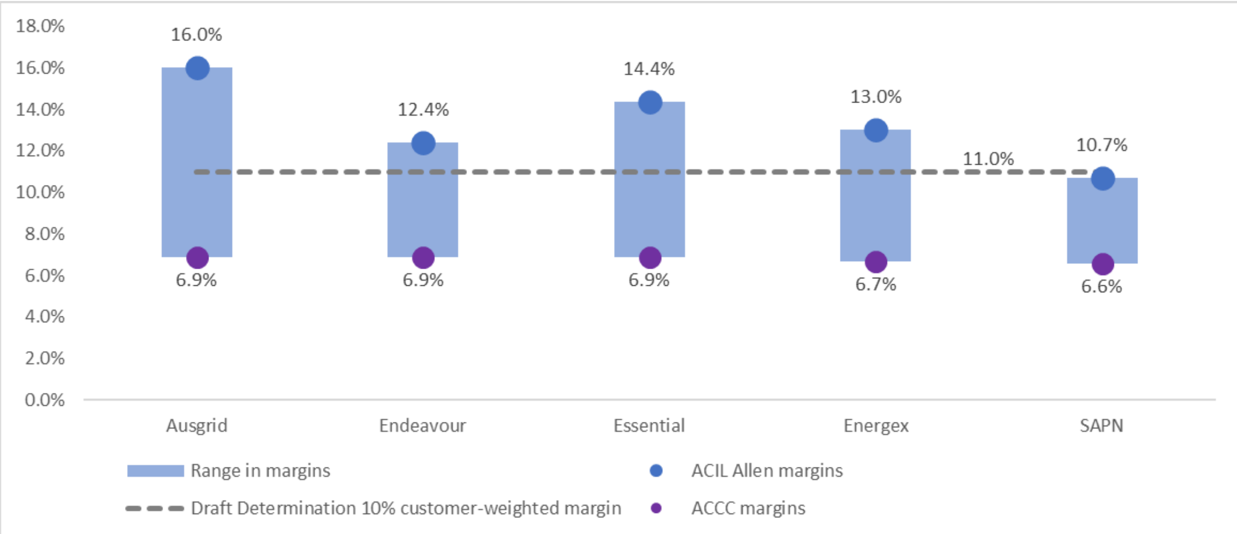
A comparison of ACIL Allen margins, ACCC customer weighted margins as well as the 15 separate margins and their weightings to derive consistent DMO 6 margins are set out in Figures 8.1 and 8.2 and Tables 8.4 and 8.5 below.

Figure 8.1 Residential ranges in inferred margins from ACIL Allen and AER analysis of ACCC prices, and draft determination margin.



Source: AER analysis of ACIL Allen, *Default Market Offer 2024–25 methodologies for estimating the retail allowance and estimated values,* February 2024, p.57; AER analysis of ACCC customer weighted prices paid on 1 August 2023. Margins inferred using DMO 5 costs.

Figure 8.2 Small business ranges in inferred margins from ACIL Allen and AER analysis of ACCC prices, and draft determination margin.



Source: AER analysis of ACIL Allen, *Default Market Offer 2024–25 methodologies for estimating the retail allowance and estimated values,* February 2024, p. 57; AER analysis of ACCC customer weighted prices paid on 1 August 2023. Margins inferred using DMO 5 costs.

Table 8.4 ACIL Allen and ACCC margins, draft determination margins for residential DMO prices

Customer Type	Region	Number of applicable customers as % of overall segment	ACIL Allen inferred margins (% of price)	Inferred margin in ACCC customer weighted price (% of price)	Aggregate ACIL Allen margin (% of price)	Aggregate inferred margin in ACCC price (% of price)	Consistent efficient margin, weighted by customer numbers (% of price)
Residential without CL	Ausgrid	21.7	2.2	6.6	**2.8**	**6.9**	**6.0**
	Endeavour	12.4	3.1	6.6	**2.8**	**6.9**	**6.0**
	Essential	7.0	4.2	6.6	**2.8**	**6.9**	**6.0**
	Energex	14.1	2.5	6.1	**2.8**	**6.9**	**6.0**
	SAPN	8.9	0.7	1.4	**2.8**	**6.9**	**6.0**
Residential with CL	Ausgrid	7.1	2.9	9.4	**2.8**	**6.9**	**6.0**
	Endeavour	5.4	2.7	9.4	**2.8**	**6.9**	**6.0**
	Essential	7.5	4.1	9.4	**2.8**	**6.9**	**6.0**
	Energex	9.9	5.0	8.5	**2.8**	**6.9**	**6.0**
	SAPN	6.1	1.5	8.2	**2.8**	**6.9**	**6.0**

Source: AER analysis of ACIL Allen, *Default Market Offer 2024–25 methodologies for estimating the retail allowance and estimated values,* February 2024, p.57; AER analysis of ACCC customer weighted prices paid on 1 August 2023. Margins inferred using DMO 5 costs. Customer proportions of overall segment is AER analysis of voluntary data request to 9 retailers at 30 September 2023.

Table 8.5 ACIL Allen and ACCC margins, draft determination margins for small business DMO prices

Customer Type	Region	Number of applicable customers as % of overall segment	ACIL Allen inferred margins (% of price)	Inferred margin in ACCC customer weighted price (% of price)	Aggregate ACIL Allen margin (% of price)	Aggregate inferred margin in ACCC price (% of price)	Consistent efficient margin, weighted by customer numbers (% of price)
Small business	Ausgrid	29.4	16.0	6.9	**13.6**	**6.8**	**11.0**
	Endeavour	14.5	12.4	6.9	**13.6**	**6.8**	**11.0**
	Essential	16.2	14.4	6.9	**13.6**	**6.8**	**11.0**
	Energex	22.1	13.0	6.7	**13.6**	**6.8**	**11.0**
	SAPN	17.9	10.7	6.6	**13.6**	**6.8**	**11.0**

Source: AER analysis of ACIL Allen, *Default Market Offer 2024–25 methodologies for estimating the retail allowance and estimated values,* February 2024, p.57; AER analysis of ACCC customer weighted prices paid on

1 August 2023. Margins inferred using DMO 5 costs. Customer proportions of overall segment is AER analysis of voluntary data request to 9 retailers at 30 September 2023.

8.3.3 Competition allowance

As discussed in the retail costs chapter, the weighted average ACCC retail and other costs included in the DMO cost stack allow retailers selling to the majority of customers to recover their costs to serve, acquire and retain customers.

Our draft decision includes an approach to determine a competition allowance as a dollar amount after the margin is applied. We have determined a method for setting the competition allowance based on the spread of retailer costs to serve so that we factor in the value for customers of the competitive tension that comes from smaller and new entrant retailers. We have also determined a framework in which we will adjust this allowance for each DMO period based on an assessment on economic conditions affecting the market and customers.

As a result, we have decided not to apply the competition allowance in the DMO 6 draft determination prices. The following sections detail our framework for setting the allowance and then determining why not to apply it.

Approach to determining the competition allowance

We have determined a competition allowance method with regard to the spread of individual retailer costs to serve (excluding customer acquisition and retention costs) reported to the ACCC under its electricity market inquiry.

The competition allowance will be calculated as a dollar per customer basis instead of a percentage basis. This means the competition allowance will move with updated retailer costs data each year instead of with movements in other elements of the cost stack (which would occur if it were set as a percentage basis).

We consider that this approach addresses Alinta Energy's concerns of subjectivity as it is calculated with reference to a benchmark average cost to serve, which has been tracked and reported by the ACCC since its June 2018 retail electricity pricing inquiry final report.[142] This approach is directly linked to the additional DMO objective of incentivising competition from a variety of retailers, as it accommodates a variety of actual retailers' varying levels of efficiency in their costs to serve, allowing them to achieve the efficient margin.

Our consideration of these factors, including the spread of retailer costs, would have led to competition allowances for DMO 6 of $66 for residential customers and $291.50 for small business customers (including GST). However, the other factor in our consideration is the overall economic and market conditions in which competition must occur. We describe these below, along with our decision not to apply the competition allowance in DMO 6.

8.4 Treatment of the competition allowance and balancing DMO objectives

The Regulations direct us in what we must consider when setting the DMO, including to provide for the recovery of costs and a reasonably profit, as well as to take into account other

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142 The ACCC has reported on differences in average costs between Tier 1 and non-Tier 1 retailers as far back as 2018–19, see ACCC, *Inquiry into the National Electricity Market*, *December 2023 Report*, Appendix C, Supplementary tables C8.6a, 8.6b, 8.11a, 8.12a. The ACCC has reported on average retailer costs as far back as 2007-08, see ACCC, *Inquiry into the National Electricity Market*, *December 2023 Report*, Appendix C, Supplementary tables C8.3, C8.10.

factors we consider relevant. In considering the competition allowance in DMO 6 we have explicitly weighed the economic environment, particularly cost of living pressures, and electricity retail market conditions, in line with the DMO objectives. Our issues paper asked stakeholders for the views on determining the appropriate balance between the 3 DMO objectives. We set out a summary of submissions received and our reasons below.

8.4.1 Stakeholder views

Most retailers considered that the current DMO settings, and envisaged glidepath of 10 and 15% retail allowances (including margin) strike the appropriate balance of the DMO objectives and that there was little evidence to support a change in approach.[143]

However, AEC and Alinta Energy considered that the current retail allowance settings did not provide enough weight to incentivising competition and investment in the market,[144] and Energy Locals argued that setting a single retail allowance for all retailers favours Tier 1 retailers, resulting in less competition in the market from new entrants.[145]

EnergyAustralia argued that the AER should provide clarity and certainty on the duration of our approach, and the circumstances it would consider if changing its approach.[146]

Submissions from the Australian Government Minister, the NSW Minister, Queensland Minister and consumer groups emphasised that in setting the DMO price the AER must have regard to any matters it considers relevant, and that a key matter of relevance is electricity affordability in the context of ongoing costs of living issues.[147] ECA, SACOSS, the combined PIAC/ACOSS/SACOSS submission and the SA Department for Energy and Mining argued the AER should place greater weight on the DMO objective of providing protection to consumers than the objective of incentivising competition.[148]

8.4.2 Draft determination

We acknowledge that the approach to determining margin and meeting the additional DMO objectives has varied across DMO determinations. We consider it is important for stakeholders to have confidence and an ability to anticipate possible changes to the calculation of the DMO price. However, we also consider it appropriate that the methodology is adaptable to the economic and energy market circumstances.

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143 AGL, *Submission to DMO 6 issues paper*, 10 November 2023, p. 4–5; Origin Energy, *Submission to DMO 6 issues paper*, 10 November 2023, p. 13; Momentum, *Submission to DMO 6 issues paper*, 3 November 2023, p. 4; Powershop and Shell Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 6; Red Energy and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, p. 4.

144 AEC, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1–2; Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 1.

145 Energy Locals, *Submission to DMO 6 issues paper,* 3 November 2023, p. 7.

146 EnergyAustralia, *Submission to DMO 6 issues paper*, 3 November 2023, p. 7.

147 The Hon Chris Bowen MP, *Submission to the issues paper*, undated, p. 1; Energy Consumers Association, *Submission to DMO 6 issues paper*, 31 October 2023, p. 1; SACOSS, *Submission to DMO 6 issues paper*, 8 November 2023, p. 2–3, 6–7, 15; The Hon Penny Sharpe MLC, *Submission to the issues paper*, 8 November 2023, p. 1; Hon Mick de Brenni, Submission to the issues paper, 5 March 2024, p. 1-2.

148 Customer Consultative Group, *Joint submission to DMO 6 issues paper,* 1 November 2023, p. 2; Energy Consumers Association, *Submission to DMO 6 issues paper*, 31 October 2023, p. 1; SACOSS, *Submission to DMO 6 issues paper*, 8 November 2023, p. 2–3, 6–7, 15; SA Department of Energy and Mining, *Submission to DMO 6 issues paper*, 10 November 2023, p. 2–3; PIAC/ACOSS/SACOSS, Submission to DMO 6 issues paper, 9 November 2023, p. 5.

We agree with stakeholders that increased inflation, cost of living pressures and electricity affordability are a relevant matter that the AER must therefore have regard to in determining DMO prices under s16(4)(d) of the regulations.

In DMO 6 the external economic conditions are extremely tough for customers. There are persistent price pressures in the economy demonstrated by headline CPI materially exceeding the RBA target band of 2–3% annual growth[149] on a sustained basis since December quarter 2021.[150] Our retail performance monitoring confirms that more customers are in debt and on hardship programs than last year, and affordability has worsened. However, customers are engaging in the market, as non-tier 1 retailers continue to gradually increase market share[151] and offer significant discounts off the DMO price.[152]

Having regard to the impact of economic conditions on energy consumers including increased inflation, cost of living pressures and electricity affordability, we consider it is appropriate for the 2024–25 DMO price to reflect a greater weighting to the DMO price protection objectives.

Therefore, for DMO 6 we will not include the competition allowance. This decision meets the requirements that the DMO price is a reasonable per-customer annual price, including a reasonable profit.[153] The conservatism in our retail margin determination described above provides further room for smaller and new entrant retailers to compete. We have weighed this and other elements of the DMO cost stack methodology up against the approach taken by other retailers and market conditions in making this decision. For example, we considered levels of competition in Victoria. Noting that the Victorian Default Offer is set under different regulatory requirements and with different policy objectives, we observe that the Victorian regulator has included margins of between 5.3% and 5.7%, has not included an allowance for competition beyond a 'modest' acquisition and retention cost[154] and has adopted a riskier approach to wholesale hedging parameters. Competition has continued to be effective in that market.

This decision not to apply the competition allowance in DMO 6 also recognises that inflation also factors in a number of other elements of the cost stack including the calculation of network and retail costs.

In future determinations we will consider the state of retail competition alongside the extent of pricing pressures in the economy in determining whether to apply or adjust a competition allowance. In particular, we will assess the performance of CPI relative to the RBA target band. We may choose to exclude the competition allowance in periods where CPI exceeds the RBA target band in a material and sustained way. To understand retail competition, we will continue to regularly monitor dynamics such as retailer market share, switching rates, spread of market offers relative to the DMO price and extent of discounts in DMO regions.

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149 See the RBA website's resource on Australia's inflation target, (accessed 4 March 2023).

150 ABS, *Consumer Price Index*, series 6401.0, Tables 1 and 2.

151 AER, *Retail Performance Quarterly update Q2 2023–24*, 19 March 2024, schedule 2; AER, *Annual retail markets report 2022–23,* November 2023, p. 3–4.

152 A number of smaller retailers have market offers with discounts greater than 15% off the residential DMO price, and 20% off the small business price, AER analysis of Energy Made Easy market offer data, 25 January 2024.

153 Regulations, s. 16(1)(b) and s. 16(4)(b).

154 ESC, *Victorian Default Offer 2023–24*, p. 40.

8.5 Summary

Our draft determination:

- Sets retail margins at 6% and 11% of residential and small business DMO prices (excluding competition allowance).
- Applies an approach to determine competition allowances reflecting the range of costs to serve among retailers. Under this approach, the 2024–25 amount would be $66 for residential customers and $291.50 for small business customers (inc. GST).
- However, as a result of economic and market conditions, and the weight of concerns about cost of living, the competition allowance will not be applied to DMO 6.

This is set out in Tables 8.6, 8.7 and 8.8 below.

Table 8.6 Residential without controlled load – efficient margin, competition allowance, comparison to DMO 5 and final DMO 6 prices

Region	Ausgrid	Endeavour	Essential	Energex	SAPN
Efficient margin	6%	6%	6%	6%	6%
Retail margin ($)	$106.41	$131.10	$152.92	$121.30	$133.34
Retail allowance in DMO 5 (RA)	$169.93	$207.22	$234.99	$165.41	$136.74
DMO 6 RA equivalent vs DMO 5 RA	-$63.52	-$76.13	-$82.07	-$44.11	-$3.40

Table 8.7 Residential with controlled load – efficient margin, competition allowance, comparison to DMO 5 and final DMO 6 prices

Region	Ausgrid	Endeavour	Essential	Energex	SAPN
Efficient margin	6%	6%	6%	6%	6%
Retail margin ($)	$148.56	$165.98	$177.82	$141.76	$166.40
Retail allowance in DMO 5 (RA)	$238.28	$276.86	$276.89	$236.33	$167.17
DMO 6 RA equivalent vs DMO 5 RA	-$89.72	-$110.88	-$99.07	-$94.57	-$0.77

Table 8.8 Small business – efficient margin, competition allowance, comparison to DMO 5 and final DMO 6 prices

Region	Ausgrid	Endeavour	Essential	Energex	SAPN
Efficient margin	11%	11%	11%	11%	11%
Retail margin ($)	$496.31	$483.34	$638.21	$460.98	$590.47
Retail allowance in DMO 5 (RA)	$999.71	$735.65	$1,008.19	$672.33	$877.35
DMO 6 RA equivalent vs DMO 5 RA	-$503.40	-$252.31	-$369.98	-$211.35	-$286.88

9 Annual usage amounts, and timing and pattern of supply

9.1 Annual usage amounts

9.1.1 Issues paper

Retailers are required to communicate discounts off market offers based on the difference between the market offer and the DMO price at the DMO assumed usage amount. Therefore, the decision about usage amounts is an important factor in customers' ability to effectively compare the options available to them.

In our DMO 5 final determination we decided:

- for residential customers for general usage and controlled usage, and small business customers for general usage to retain the same usage amounts as in the previous determination.
- to add 1 day's consumption to annual usage from the previous determination to reflect that 2023–24 is a leap year.

To provide consistency and continuity for stakeholders, the issues paper proposed to use the same usage amounts for the DMO 6 determination and revert to 365 days, with the intention to review these in the next DMO methodology review as part of the 2025–26 (DMO 7) process.

The issues paper also noted the ACCC had released its Inquiry into the National Electricity Market – June 2023 report[155], which included updated findings on residential and small business usage for that period of time. We considered that those findings show our DMO 5 assumed annual usage amounts remained broadly representative of their respective customer groups.

9.1.2 Stakeholder views

Four stakeholder submissions discussed issues relating to annual usage amounts. To provide consistency with the majority of DMO determinations, the South Australian Department for Energy and Mining expects the DMO 6 determination to revert the annual usage from 4,011 kWh for South Australian residential customers without controlled load (due to a leap year in 2023–24) to 4,000 kWh, given there are 365 days in 2024–25.[156]

[155] ACCC, *Inquiry into the National Electricity Market*, June 2023 report.

[156] SA Department for Energy and Mining, *Submission to DMO 6 Issues Paper*, 10 November 2023, p.5.

We acknowledge SACOSS's recommendation for the AER to access more accurate consumption data, even if such data sources lacked transparency.[157] However, transparency, stability, certainty and practicality were at the forefront of the decisions we made in the previous DMO determinations. No changes were proposed because we considered the impacts of any large changes would exacerbate uncertainty and complexity in a market already experiencing volatility. We consider the approach of using ACCC publicly available consumption data[158] provides an appropriate balance of transparency and accuracy in annual usage determinations and a way to avoid information asymmetry.

ECA's submission and the joint submission from the AER's Customer Consultative Group expressed similar concerns that retailers may be structuring their retail tariffs so that customers that consume more than the DMO usage amounts return a higher margin for the retailer.[159] The AER's Customer Consultative Group urged the AER to look at retailers' customer profile and generation portfolio and determine whether they are doing that. They also suggested the AER consider how retailers' approaches may undermine the intent of the DMO.

ECA acknowledged that the AER must determine broadly representative annual supply amounts for residential and small business customers in each region. Despite this, they argued this will become increasingly difficult with changing behaviour and the continued adoption of consumer energy resources (such as solar panels, batteries, EV chargers and other manageable loads). As a price cap, this has the potential to cause harm if a consumer uses more than the defined amount. As a reference price, it also has the potential to cause harm when a consumer's actual usage differs greatly from the profile determined by the AER.

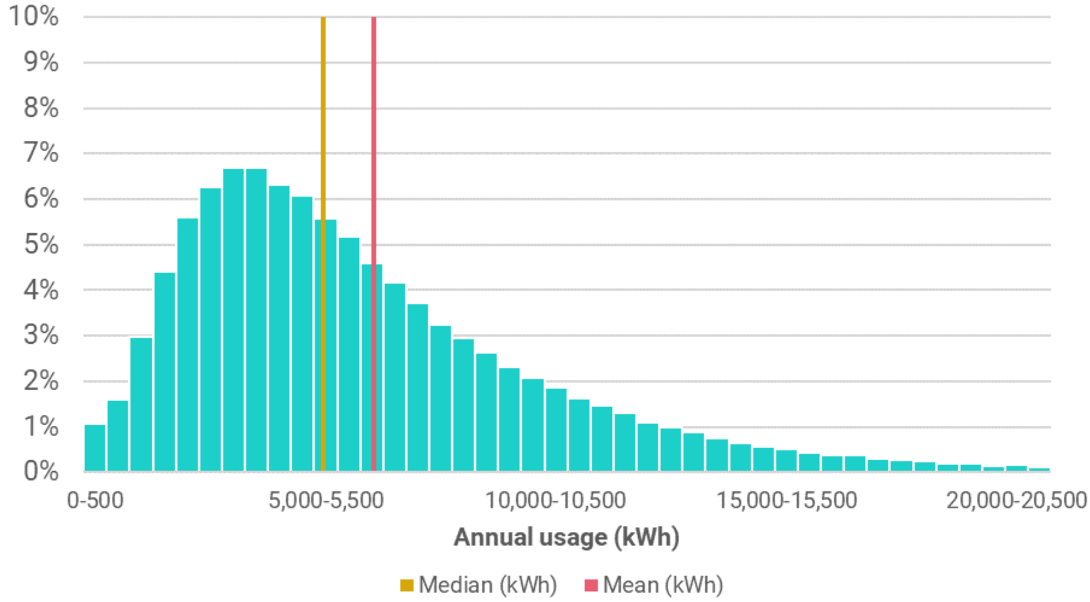
We acknowledge and agree with ECA's point that determining a single annual usage amount that is 'broadly representative of a customer type for a particular region is challenging'. Residential and particularly small business customers exhibit a large range of usage amounts, as shown in Figures 9.1 and 9.2 from the ACCC Inquiry into the National Electricity Market June 2023 report.

[157] SACOSS, *Submission to DMO 6 Issues Paper*, 8 November 2023, p.2.

[158] Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023

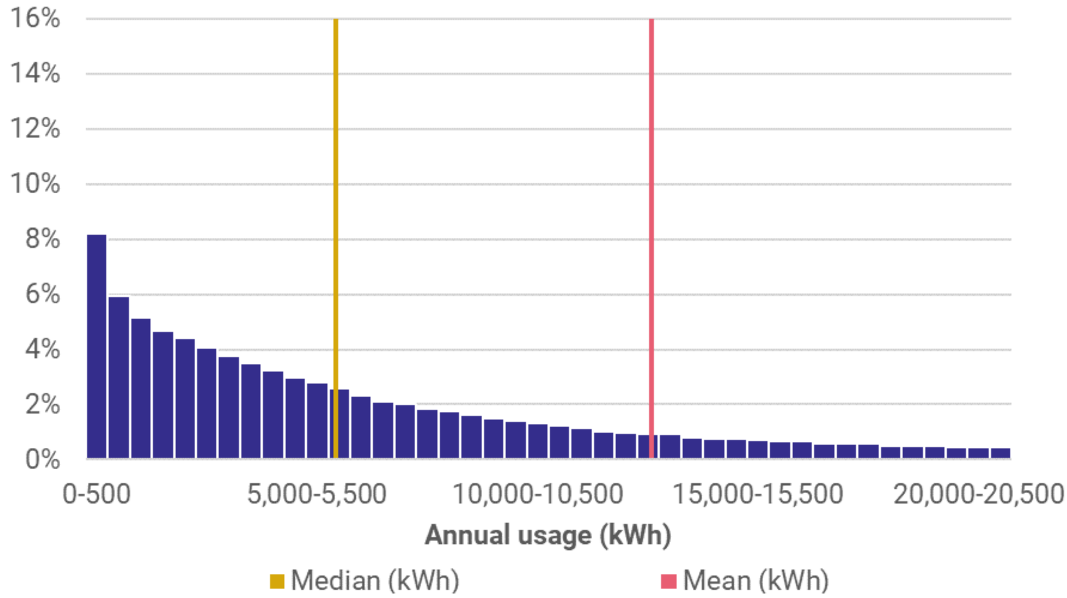
[159] Energy Consumers Australia, *Submission to DMO 6 Issues Paper*, 31 October 2023, p. 4; Customer Consultative Group, *Joint submission to DMO 6 Issues Paper*, 2 November 2023, p.1.

Figure 9.1 Proportions of NSW residential customers in different usage brackets



Source: ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Figure A13.1 Note - ACCC data also provides usage information for SE Queensland and South Australia.

Figure 9.2 Proportions of NSW small business customers in different usage brackets



Source: ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Figure A14.1 Note - ACCC data also provides usage information for SE Queensland and South Australia.

This analysis from the ACCC suggests that our assumed residential usage amounts are:

- in NSW around the 35th to 71st percentile and between 38% lower and 17% higher than the average usage of 6,311 kWh (depending on region and inclusion or exclusion of controlled load)[160]

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[160] AER analysis comparing NSW residential assumed annual usage amounts to ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Table A13.1.

- in SE Queensland around the 50th to 71st percentile and between 23% lower and 5% higher than the average usage of 5,982 kWh (depending on inclusion or exclusion of controlled load)[161]
- in South Australia around the 50th to 71st percentile and between 19% lower and 22% higher than the average usage of 4,935 kWh (depending on inclusion or exclusion of controlled load).[162]

This analysis from the ACCC suggests that our assumed small business usage amount of 10,000 kWh is:

- in NSW around the 66th percentile and 22% lower than the average usage of 12,809 kWh[163]
- in SE Queensland around the 61st percentile and around 31% lower than the average usage of 14,469 kWh[164]
- in South Australia around the 72nd percentile and around 4% lower than the average usage of 10,435 kWh.[165]

Therefore, we consider our assumed usage amounts remain broadly representative as they sit within the interquartile range.

We acknowledge the AER Customer Consultative Group's concerns that retailers are able to structure offers to return a greater margin for customers that consume more than the DMO assumed usage amounts.

Unfortunately, under the current form of the DMO, which is a regulated reference price for standing and market offers at an assumed usage, we do not consider it possible to fully prevent retailers structuring offers in such a way to generate a greater proportion of revenue for customers whose usage is different to the DMO assumed annual usage.

For example, increasing the DMO annual usage amount would reduce retailers' ability to structure offers that appear to be good value at usages below the new annual usage amount while being poor value at higher usage amounts.

However, increasing the DMO annual usage would then allow retailers to structure offers that:

[161] AER analysis comparing NSW residential assumed annual usage amounts to ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Table A13.3.

[162] AER analysis comparing NSW residential assumed annual usage amounts to ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Table A13.2.

[163] AER analysis comparing NSW residential assumed annual usage amounts to ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Table A14.1.

[164] AER analysis comparing NSW residential assumed annual usage amounts to ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Table A14.3.

[165] AER analysis comparing NSW residential assumed annual usage amounts to ACCC, Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market, June 2023 – Supplementary Table A14.2.

- appear to be good value at a high usage because they have a high discount off the reference price
- are poor value at low usage amounts.

A retailer could achieve this by structuring offers that:

- have a high daily supply charge ($/day) and low energy usage charge (c/kWh) or
- have a declining block tariff (that is, high c/kWh for low usage customers and low c/kWh for the remaining energy consumed by high usage customers).

Such offers would compare favourably at higher DMO usage amount but be poor value to customers that consume a low amount.

To test the extent to which retailers may be structuring their retail tariffs so that offers that appear to be cheap at the reference price become poor value at different usage amounts, we have carried out analysis using the latest ACCC usage distribution data[166] and market offers from Energy Made Easy website at different usage amounts.

This analysis examined whether the market offer identified as the cheapest offer based on the DMO annual usage amount ('DMO identified cheapest offer') continues to be the cheapest offer at smaller and greater usage amounts. When combined with the ACCC usage distribution data, this allowed us to assess the extent to which the DMO in its role as a reference price performs well in identifying the cheapest market offer for customers whose usage amounts are smaller or larger than the DMO annual usage amount determination.

This analysis:

- estimates the proportion of residential and small business customers for whom the DMO identified cheapest offer continues to be the cheapest offer at other usage amounts.
- calculates the further discount in dollar and percentage terms available in the actual cheapest offer for the annual usage amounts for which the DMO identified cheapest offer was no longer the cheapest offer.
- examines whether the DMO identified cheapest offer is also the cheapest offer at the median and mean usage in the ACCC data
- estimates a customer-weighted average price of each available market offer across all usage amounts. This provides an overall ranking of market offers from cheapest to most expensive across the entire distribution of usage.

This analysis is set out in detail in Appendix E. In summary we found for residential customers:

- The percentage of customers for whom the DMO identified cheapest offer continues to be the cheapest market offer sits between 82.3% and 92.3% depending on the region. This offer was no longer the cheapest offer for customers consuming small amounts of energy (less than 1,400 to 2,700 kWh depending on region) or large amounts of energy (exceeding 11,900, 12,600 or 13,500 kWh in Endeavour, Ausgrid and SAPN). In Essential and Energex, the offer continued to be the cheapest above the assumed usage amount.

166 ACCC, *Appendix E - Supplementary spreadsheet with billing data and figures – ACCC Inquiry into the National Electricity Market,* June 2023, Supplementary Tables A13.1 – A13.3 and A14.1 – A14.3.

- For the small proportion (2% to 9% depending on region) of customers that consume large amounts falling outside these usage ranges for which the DMO identified cheapest offer remains the cheapest, these customers would only have missed out on up to a further $175 discount by not switching to the actual cheapest offer. However, this was for large annual usage amounts of 21,000 kWh and represents only a further 0.7% to 2.8% discount.
- For the small proportion (4% to 15% depending on region) of customers that consume little to no energy and falling outside these usage ranges for which the DMO identified cheapest offer remains the cheapest, these customers by not switching to the actual cheapest offer would only have missed out on up to a further $61, except in SAPN where they would have missed out on up to a further $195.
- The DMO identified cheapest offer is also the cheapest at both ACCC median usage and ACCC average usage.
- The DMO identified cheapest offer is also has the cheapest customer-weighted average price across the usage distribution.

Therefore, despite the range in annual usages among residential customers, we consider the current assumed annual usage amount (and DMO reference price at this usage amount) for residential customers in each distribution region performs well at identifying the cheapest market offer for the vast majority of residential customers.

For small business customers we found:

- The percentage of customers for whom the DMO identified cheapest offer continues to be the cheapest market offer sits between 33.0% and 71.1% depending on the region. This offer was no longer the cheapest offer for customers consuming less than 3,300 kWh (Energex), 5,000 kWh (SAPN), 5,200 kWh (Endeavour), 5,900 kWh (Ausgrid) and 9,500 kWh (Essential). But it continues to be the cheapest offer for customers consuming over 10,000 kWh.
- The DMO identified cheapest offer:
  - is the cheapest offer for the majority of customers in Energex (71.1% of customers) and Endeavour (51.3% of customers)
  - is the cheapest offer for the second largest group of customers, (47.4% vs 52.6% in Ausgrid, 33.0% vs 41.7% in Essential, 41.8% vs 46.6% in SAPN).
- No alternative single offer is the cheapest for the majority of customers, except in Ausgrid, where another offer is the cheapest for 52.6% of customers (vs the other 47.4% of customers for whom the DMO identified cheapest offer is the cheapest).
- Customers that consume less than 3,300 to 9,500 kWh (52.6% Ausgrid, 48.7% Endeavour, 67.0% Essential, 28.9% Energex, 58.2% SAPN) would have missed out on up to a further $48 to $426 discount by not switching to the actual cheapest offer.
- The DMO identified cheapest offer is the cheapest for ACCC average usage and either the cheapest or second cheapest at ACCC median usage.
- The DMO identified cheapest offer is either the cheapest or second cheapest customer-weighted average price across the usage distribution.

Therefore, despite the significant range in annual usages among small business customers, we consider the current assumed annual usage amount (and DMO reference price at this usage) performs reasonably well at identifying the cheapest offer in the market. This is because:

- it performs extremely well for all customers that consume above 10,000 kWh (which includes the ACCC average usage)
- it performs well for customers on median small business usage because it is either the cheapest or second cheapest offer
- with the exception of Ausgrid, there isn't an alternative offer that continues to be the cheapest for the majority of small business usages across the significant range of annual usage.

However, we do note that it does not perform as well for small business customers that consume below 3,300 to 9,500 kWh depending on the region.

9.1.3 Draft determination

We agree with the South Australian Department for Energy and Mining's suggestion to provide consistency and continuity for stakeholders in the number of days we calculate the annual usage. We propose to use the same usage amounts for residential customers for general usage and controlled usage, and small business customers for general usage as in previous determinations for the DMO 6 determination (365 days). We will review annual usage as part of the next DMO methodology for the 2025–26 (DMO 7) process.

Having considered stakeholder submissions and the available information on residential annual usage, we consider the amounts are still broadly representative of residential and small business customer usage. We believe the current approach provides accurate consumption data, consistency and transparency by adhering to the established methodology, allows for more objective analysis and best achieves the DMO policy objectives.

Our draft determination retains the current annual usage benchmarks for residential and small business customers, including the current controlled load amounts, for DMO 6.

9.2 Timing and pattern of supply

9.2.1 Issues paper

In the issues paper we proposed to continue to update the timing and pattern of supply usage profiles using new AEMO interval meter data and to retain the below key assumptions from previous determinations:

- assume the 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 interval meter data for each region, averaged over 3 years
- specify usage at 30-minute intervals.

We considered this approach remains reasonable and provides transparency and major benefits to stakeholders by balancing accuracy and ease of implementation.

9.2.2 Stakeholder views

Most submissions did not consider timing and pattern of supply, with 1st Energy and Alinta Energy expressing their agreement on the proposed approach continuing, which is likely to be broadly representative for DMO 6.[167] Also, Alinta Energy considers this may require further analysis as the advanced meter roll out progresses and cost-reflective network and retail tariffs become more common.

However, ECA's submission noted that the advertised discount, which is calculated by comparing the annual price of a TOU offer based on the DMO usage pattern to the reference price, could be inaccurate for many customers and lead to higher than anticipated bills if they use more energy in peak times than the AER's time of use pattern outlines.[168]

We concede ECA's concern on the issue that a customer with different TOU to the assumed usage in the DMO could pick an offer that is not advertised as the cheapest. The actual best TOU offer for a customer will depend on their individual household characteristics. If their usage differs from the average usage, which is what the DMO TOU profiles are based on, then the TOU offer that is identified as having the greatest discount may not be the best offer for that customer.

We recommend customers with smart meters take advantage of their features and enter the National Meter Identifier on comparison websites such as Energy Made Easy when shopping around. This will identify the best offer given that customer's unique usage over the past 12 months.

Also, the submission from SACOSS expressed concerns on retailers' ability to transfer smart meter customers onto time of use retail contracts with no option to choose a flat rate tariff.[169] They argue that South Australian smart meter customers (around 41% of customers) have an underlying default time of use network tariff, which has been applied since around 2021. As at Q3 2022–23, 79.9% of South Australian smart meter customers were on a time of use tariff (up from 52.3% in Q3 2021–22).

This represents a large percentage of South Australian energy consumers (around 32%). SACOSS considers retailers' approach to transferring customers (without consent or advanced notification) to time of use tariffs has implications for choice, competition, usage patterns and network cost recovery, and this will have increasing implications with the accelerated roll-out of smart meters to commence in July 2025.

We acknowledge SACOSS's concern on implications of compulsory time of use retail offers on South Australian consumers. However, we do not set tariffs or specify peak time periods directly under the DMO, so we consider that retailers and policymakers are best placed to consider how to address the issues raised by SACOSS.

9.2.3 Draft determination

Our draft determination for timing and pattern of supply is that we will update the usage profiles using new AEMO interval meter data but retain our approach from DMO 5.

This approach for determining the timing and pattern of supply to represent TOU customers updates the usage profiles using new AEMO interval meter data but retains our key assumptions from previous determinations. That is, we will:

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167 1st Energy, *Submission to DMO 6 Issues Paper*, 3 November 2023, p. 4; Alinta Energy, *Submission to DMO 6 Issues Paper*, 3 November 2023, p. 8.

168 Energy Consumers Australia, *Submission to DMO 6 Issues Paper*, 31 October 2023, p. 5.

169 SACOSS, *Submission to DMO 6 Issues Paper*, 8 November 2023, p. 16.

- 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 using the AEMO interval meter data for each region, averaged over 3 years
- specify usage at 30-minute intervals.

We have updated the single-day usage profile and specified usage for each 30-minute interval over a 24-hour period (see Appendix C).

10 Appendices

Appendix A – List of submissions to the draft determination

Appendix B – Advanced meter costs

Appendix C – Legislative instrument

Appendix D – DMO 5 to DMO 6 price movements

Appendix E – Market offers analysis at different usage amounts

A. List of submissions to the draft determination

Following release of the issues paper on 5 October 2023, we invited stakeholder submissions. The following are the stakeholders who engaged in this process.

Government & Market Bodies

1. South Australian Department for Energy and Mining, 10 November 2023
2. Business SA Chamber of Commerce and Industry, 1 November 2023
3. Hon Penny Sharpe MLC, NSW Minister for Energy, 8 November 2023
4. Hon Chris Bowen MP, Minister for Climate Change and Energy, (7 December 2023)
5. Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Queensland Minister, 29 February 2024
6. Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Queensland Minister, 5 March 2024

Industry Association

7. Australian Energy Council (AEC), 3 November 2023

Retailers

8. 1st Energy, 3 November 2023
9. AGL, 10 November 2023
10. Alinta Energy, 3 November 2023
11. EnergyAustralia, 3 November 2023
12. Energy Locals, 3 November 2023
13. GloBird Energy, 3 November 2023
14. Momentum Energy, 3 November 2023
15. Origin Energy, 10 November 2023
16. Powershop and Shell Energy, 3 November 2023
17. Red Energy/Lumo Energy, 9 November 2023
18. Simply Energy, 3 November 2023

Consumer Groups/Representatives

19. PIAC/ACOSS/SACOSS, 9 November 2023
20. Energy Consumers Australia (ECA), 31 October 2023
21. SACOSS, 8 November 2023
22. Customer Consultative Group, *Joint submission to DMO 5 issues paper*, 2 November 2023

B. Advanced meter costs

We requested retailers selling to approximately 93% of customers in DMO regions to provide the number of customers on advanced meters and accumulation meters for each DMO region and customer type as at 30 September 2023, and projected installations for the mid-point of DMO 6 (31 December 2024). We also asked retailers to provide the average costs they incur per advanced meter and the extent to which a portion of these costs are recovered in up-front and/or one-off installation fees. Tables B.1 and B.2 set out our calculations for estimating advanced meter costs per residential and small business customer.

Table B.1 Residential advanced meter counts and per customer costs

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	45,789,073	41,726,308	35,190,301	54,597,697	35,291,949	**212,595,328**
Total advanced meter customers	415,720	389,776	290,816	498,586	338,736	**1,933,634**
Average cost incurred per advanced meter ($) (ex GST)	110.14	107.05	121.01	109.51	104.19	**109.95**
ACS metering allowance included in network component ($) (ex GST)	29.60	15.51	59.61	44.23	26.91	**N/A**
Capital metering charge within ACS metering allowance ($)	15.32	3.74	7.87	27.81	9.95	**N/A**
Advanced meter installations where retailer has incurred a capital metering charge for replacing an accumulation meter (%)	85.6%	85.6%	85.6%	85.6%	85.6%	**85.6%**
Average legacy capital metering charges incurred per advanced meter ($)	13.12	3.20	6.73	23.81	8.51	**N/A**
Average per advanced meter costs net of ACS metering allowance, including legacy meter capital charges ($)	94.50	85.90	85.30	90.81	86.84	**N/A**
Total customers	1,512,796	948,706	739,718	1,357,877	832,285	**5,391,382**
Customers with advanced meters (%)	27.48%	41.09%	39.31%	36.72%	40.70%	**35.87%**
Advanceged meter cost per customer net of ACS metering allowance in network component, including legacy meter capital charges ($)	25.97	35.29	33.54	33.34	35.34	**N/A**
Additional capital allowance adjustment (see Table B.3)	0.50	0.98	0.86	0.79	0.83	**N/A**

Table B.2 Small business advanced meter counts and per customer costs

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	3,728,181	2,126,007	2,613,205	3,706,402	2,732,393	**14,906,188**
Total advanced meter customers	30,211	17,368	21,779	30,371	21,593	**121,322**
Average cost incurred per advanced meter ($) (ex GST)	123.40	122.41	119.99	122.04	126.54	**122.86**
ACS metering allowance included in network component ($) (ex GST)	38.70	15.51	59.61	44.23	26.91	**N/A**
Capital metering charge within ACS metering allowance ($)	23.37	5.47	7.87	27.81	9.95	**N/A**
Advanced meter installations where retailer has incurred a capital metering charge for replacing an accumulation meter (%)	85.6%	85.6%	85.6%	85.6%	85.6%	**85.6%**
Average legacy capital metering charges incurred per advanced meter ($)	20.01	4.69	6.73	23.81	8.51	**N/A**
Average per advanced meter costs net of ACS metering allowance, including legacy meter capital charges ($)	105.90	91.42	84.28	103.34	109.20	**N/A**
Total customers	136,553	67,427	75,253	102,756	83,048	**465,037**
Customers with advanced meters (%)	22.12%	25.76%	28.94%	29.56%	26.00%	**26.09%**
Advanced meter cost per customer net of ACS metering allowance in network component, including legacy meter capital charges ($)	23.43	23.55	24.39	30.54	28.39	**N/A**
Capital allowance adjustment (See Table B.4)	0.45	0.65	0.62	0.72	0.76	**N/A**

Table B.3 Calculation of residential capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 6, based on actual installs at 30 September 2023	$25.97	$35.29	$33.54	$33.34	$35.34
Smart meter allowance based on retailer projected installations at 31 December 2024	$30.99	$45.11	$42.11	$41.24	$43.68
Projected shortfall in Smart Meter Allowance at 31 December 2024	$5.02	$9.81	$8.58	$7.89	$8.34
Weighted average cost of capital applied to shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (excl. GST)	$0.50	$0.98	$0.86	$0.79	$0.83

Table B.4 Calculation of small business capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 6, based on actual installs at 30 September 2023	$23.43	$23.55	$24.39	$30.54	$28.39
Smart meter allowance based on retailer projected installations at 31 December 2024	$27.96	$30.10	$30.63	$37.77	$35.08
Projected shortfall in Smart Meter Allowance at 31 December 2024	$4.53	$6.55	$6.24	$7.23	$6.69
Weighted average cost of capital applied to shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (excl. GST)	$0.45	$0.65	$0.62	$0.72	$0.67

C. Legislative instrument

AUSTRALIA

Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2024

The Australian Energy Regulator makes the following determination.

Dated [ ] May 2024 Australian Energy Regulator

1. Name

This instrument is the *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2024.*

2. Commencement

This instrument commences on 1 July 2024.

3. Authority

This instrument is made under section 16(1) of the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Regulations).

4. Definitions

In this Determination:

a) ***Regulations*** means the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019*; and

b) ***Residential Annual Usage without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

c) ***Residential Annual Price without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

d) ***Residential Annual Usage with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

e) ***Residential Annual Price with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

f) ***Small Business Annual Usage*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

g) ***Small Business Annual Price*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

h) ***General Usage*** means the non-controlled load usage of a small customer under s 6(2)(a) of the Regulations; and

i) ***Controlled Load Usage*** means the controlled load usage of a small customer under s 6(2)(a) of the Regulations.

j) Terms defined in the Regulations have the same meaning in this instrument.

5. Per-customer usage determination

In accordance with s 16(1)(a)(i) of the Regulations, the AER determines the per-customer amount of electricity supplied in specified distribution regions to small customers of the following types:

Per-customer annual usage determination (365 days p.a. in 202425)				
Distribution region	**Residential Annual Usage without Controlled Load**	**Residential Annual Usage with Controlled Load**		**Small Business Annual Usage**
		General Usage	***Controlled Load Usage***	
Ausgrid	3,900 kWh	4,800 kWh	2,000 kWh	10,000 kWh
Endeavour Energy	4,900 kWh	5,200 kWh	2,200 kWh	10,000 kWh
Energex	4,600 kWh	4,400 kWh	1,900 kWh	10,000 kWh
Essential Energy	4,600 kWh	4,600 kWh	2,000 kWh	10,000 kWh
SA Power Networks	4,000 kWh	4,200 kWh	1,800 kWh	10,000 kWh

6. Timing or pattern of supply determination

In accordance with s 16(1)(a)(ii) of the Regulations, the AER determines the timing or pattern of the supply of electricity in specified distribution regions to small customers:

a) Seasonality assumptions, all tariff and customer types

For all tariff and customer types, consumption has no seasonal weighting. That is, kilowatt hours consumed are assumed to be the same on each day of the year.

b) Daily usage profile for Flexible Tariffs (Time of Use tariffs, including the South Australian TOU controlled load tariff) – Residential Usage without Controlled Load and General Usage / Residential Usage with Controlled Load

i. Ausgrid distribution region

Flexible Tariff (Time of Use tariff) daily usage profile – Daily Residential Usage without Controlled Load (3,900 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2326**	**0.2247**	**0.2140**	**0.1900**	**0.1725**	**0.1563**	**0.1450**	**0.1379**	**0.1348**	**0.1348**	**0.1399**	**0.1484**	**0.1651**	**0.1869**	**0.2012**	**0.2168**	**0.2210**	**0.2213**	**0.2207**	**0.2186**	**0.2162**	**0.2142**	**0.2124**	**0.2125**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2138**	**0.2140**	**0.2128**	**0.2114**	**0.2106**	**0.2111**	**0.2142**	**0.2224**	**0.2346**	**0.2514**	**0.2731**	**0.2997**	**0.3148**	**0.3180**	**0.3120**	**0.3040**	**0.2974**	**0.2898**	**0.2776**	**0.2663**	**0.2595**	**0.2541**	**0.2465**	**0.2379**

Flexible Tariff (Time of Use tariff) daily usage profile – Daily General usage – Daily Residential Usage with Controlled Load (4,800 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2863**	**0.2765**	**0.2634**	**0.2339**	**0.2124**	**0.1924**	**0.1784**	**0.1697**	**0.1659**	**0.1659**	**0.1721**	**0.1827**	**0.2033**	**0.2301**	**0.2476**	**0.2669**	**0.2720**	**0.2724**	**0.2716**	**0.2691**	**0.2661**	**0.2636**	**0.2614**	**0.2615**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2632**	**0.2633**	**0.2619**	**0.2602**	**0.2591**	**0.2598**	**0.2637**	**0.2737**	**0.2888**	**0.3094**	**0.3361**	**0.3689**	**0.3874**	**0.3914**	**0.3840**	**0.3742**	**0.3660**	**0.3567**	**0.3417**	**0.3278**	**0.3194**	**0.3128**	**0.3034**	**0.2928**

ii. Endeavour Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,900 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2959**	**0.2865**	**0.2601**	**0.2252**	**0.1991**	**0.1805**	**0.1692**	**0.1628**	**0.1619**	**0.1647**	**0.1740**	**0.1864**	**0.2078**	**0.2336**	**0.2473**	**0.2642**	**0.2682**	**0.2651**	**0.2653**	**0.2642**	**0.2621**	**0.2604**	**0.2589**	**0.2607**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2623**	**0.2626**	**0.2617**	**0.2636**	**0.2677**	**0.2728**	**0.2826**	**0.2999**	**0.3201**	**0.3445**	**0.3679**	**0.3984**	**0.4127**	**0.4124**	**0.4021**	**0.3912**	**0.3791**	**0.3656**	**0.3483**	**0.3255**	**0.3194**	**0.3196**	**0.3144**	**0.3062**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (5,200 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.3140**	**0.3040**	**0.2760**	**0.2390**	**0.2113**	**0.1916**	**0.1795**	**0.1727**	**0.1718**	**0.1748**	**0.1846**	**0.1978**	**0.2206**	**0.2479**	**0.2625**	**0.2804**	**0.2846**	**0.2813**	**0.2816**	**0.2804**	**0.2782**	**0.2763**	**0.2748**	**0.2767**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2784**	**0.2787**	**0.2777**	**0.2797**	**0.2841**	**0.2896**	**0.2998**	**0.3182**	**0.3397**	**0.3656**	**0.3904**	**0.4228**	**0.4380**	**0.4376**	**0.4267**	**0.4152**	**0.4023**	**0.3880**	**0.3696**	**0.3454**	**0.3389**	**0.3392**	**0.3337**	**0.3250**

iii. Energex distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.1963**	**0.1803**	**0.1697**	**0.1599**	**0.1527**	**0.1479**	**0.1452**	**0.1441**	**0.1463**	**0.1517**	**0.1635**	**0.1790**	**0.2029**	**0.2316**	**0.2577**	**0.2681**	**0.2705**	**0.2689**	**0.2693**	**0.2687**	**0.2669**	**0.2661**	**0.2653**	**0.2676**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2699**	**0.2718**	**0.2745**	**0.2761**	**0.2800**	**0.2819**	**0.2881**	**0.2987**	**0.3116**	**0.3307**	**0.3509**	**0.3753**	**0.3922**	**0.3998**	**0.3886**	**0.3777**	**0.3709**	**0.3495**	**0.3265**	**0.3088**	**0.2939**	**0.2758**	**0.2488**	**0.2201**

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

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.1878**	**0.1724**	**0.1623**	**0.1530**	**0.1461**	**0.1414**	**0.1389**	**0.1378**	**0.1399**	**0.1451**	**0.1564**	**0.1712**	**0.1940**	**0.2215**	**0.2465**	**0.2565**	**0.2588**	**0.2572**	**0.2576**	**0.2570**	**0.2553**	**0.2546**	**0.2538**	**0.2560**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2582**	**0.2600**	**0.2626**	**0.2641**	**0.2678**	**0.2697**	**0.2756**	**0.2858**	**0.2980**	**0.3164**	**0.3356**	**0.3590**	**0.3751**	**0.3825**	**0.3717**	**0.3613**	**0.3548**	**0.3343**	**0.3123**	**0.2954**	**0.2811**	**0.2638**	**0.2380**	**0.2105**

iv. Essential Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2723**	**0.2719**	**0.2638**	**0.2516**	**0.2309**	**0.2069**	**0.1882**	**0.1764**	**0.1714**	**0.1712**	**0.1793**	**0.1924**	**0.2147**	**0.2365**	**0.2458**	**0.2582**	**0.2597**	**0.2536**	**0.2535**	**0.2512**	**0.2486**	**0.2468**	**0.2439**	**0.2411**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2429**	**0.2430**	**0.2416**	**0.2388**	**0.2387**	**0.2401**	**0.2452**	**0.2557**	**0.2685**	**0.2854**	**0.3138**	**0.3493**	**0.3708**	**0.3723**	**0.3605**	**0.3474**	**0.3365**	**0.3233**	**0.3147**	**0.3091**	**0.3114**	**0.2981**	**0.2856**	**0.2802**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,600 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2723**	**0.2719**	**0.2638**	**0.2516**	**0.2309**	**0.2069**	**0.1882**	**0.1764**	**0.1714**	**0.1712**	**0.1793**	**0.1924**	**0.2147**	**0.2365**	**0.2458**	**0.2582**	**0.2597**	**0.2536**	**0.2535**	**0.2512**	**0.2486**	**0.2468**	**0.2439**	**0.2411**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2429**	**0.2430**	**0.2416**	**0.2388**	**0.2387**	**0.2401**	**0.2452**	**0.2557**	**0.2685**	**0.2854**	**0.3138**	**0.3493**	**0.3708**	**0.3723**	**0.3605**	**0.3474**	**0.3365**	**0.3233**	**0.3147**	**0.3091**	**0.3114**	**0.2981**	**0.2856**	**0.2802**

v. South Australian Power Networks distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,000 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2577**	**0.3017**	**0.2996**	**0.2542**	**0.2145**	**0.1884**	**0.1731**	**0.1557**	**0.1441**	**0.1394**	**0.1417**	**0.1498**	**0.1674**	**0.1802**	**0.2012**	**0.2064**	**0.2008**	**0.1963**	**0.1958**	**0.2001**	**0.2048**	**0.2125**	**0.2150**	**0.2157**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2145**	**0.2113**	**0.2088**	**0.2073**	**0.2092**	**0.2108**	**0.2164**	**0.2235**	**0.2397**	**0.2594**	**0.2900**	**0.3212**	**0.3379**	**0.3383**	**0.3286**	**0.3182**	**0.3075**	**0.2957**	**0.2797**	**0.2586**	**0.2339**	**0.2091**	**0.1959**	**0.2274**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,200 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2705**	**0.3168**	**0.3146**	**0.2669**	**0.2252**	**0.1978**	**0.1818**	**0.1635**	**0.1513**	**0.1464**	**0.1488**	**0.1573**	**0.1758**	**0.1892**	**0.2113**	**0.2167**	**0.2108**	**0.2061**	**0.2056**	**0.2101**	**0.2151**	**0.2231**	**0.2258**	**0.2265**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2252**	**0.2219**	**0.2192**	**0.2176**	**0.2196**	**0.2214**	**0.2272**	**0.2346**	**0.2516**	**0.2723**	**0.3045**	**0.3373**	**0.3547**	**0.3552**	**0.3450**	**0.3341**	**0.3229**	**0.3105**	**0.2936**	**0.2715**	**0.2456**	**0.2195**	**0.2057**	**0.2388**

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

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

c) Controlled Load (CL) annual usage allocations

i. Ausgrid distribution region (kWh/year)

CL1 only	CL2 only	CL 1 and 2 (% of total)	
		CL1 (67%)	CL2 (33%)
2,000	2,000	1,340	660

ii. Endeavour Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (67%)	CL 2 (33%)
2,200	2,200	1,474	726

iii. Energex distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (29%)	CL 2 (71%)
1,900	1,900	551	1,349

iv. Essential Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (77%)	CL 2 (23%)
2,000	2,000	1,540	460

v. South Australian Power Networks distribution region (kWh/year)[170]

CL 1 only	CL 2 only	CL 1 and 2
1,800	NA	NA

7. Per-customer annual price determination

[170] Refer to section 6.b)v. for the daily usage profile for the TOU controlled load tariff.

In accordance with s 16(1)(b) of the Regulations, the AER determines what it considers the reasonable per-customer annual price for supplying electricity in specified distribution regions to small customers of the types set out below.

Per-customer draft annual price determination (all prices GST-inclusive)			
Distribution region	**Annual Residential Price without Controlled Load**	**Annual Residential Price with Controlled Load**	**Small Business Annual Price**
Ausgrid	$1,773	$2,476	$4,512
Endeavour Energy	$2,185	$2,766	$4,394
Energex	$2,022	$2,363	$4,191
Essential Energy	$2,549	$2,964	$5,802
SA Power Networks	$2,222	$2,773	$5,368

DATED THIS XX DAY OF
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D. DMO 5 to DMO 6 price movements

The charts in this appendix show the movement in the DMO cost components between DMO 5 and DMO 6, with the overall height indicating the total DMO price for each DNSP.

We note that:

- Network, retail and environment cost components in DMO 6 are calculated using predominately the same methodology as DMO 5, so the changes directly reflect year-on-year movement. Network costs include costs of the NSW Roadwork costs in NSW and environmental costs include known applicable environmental schemes.
- Changes to the wholesale cost component also reflect the impact of the methodological adjustment of blending the load profile with interval meter data for NSW. Additionally in Energex and SAPN, adopting the mid-point of the two WEC's resulting from the different NSLPs.

Figure D.1 Residential without CL, % change from DMO 5 (nominal)

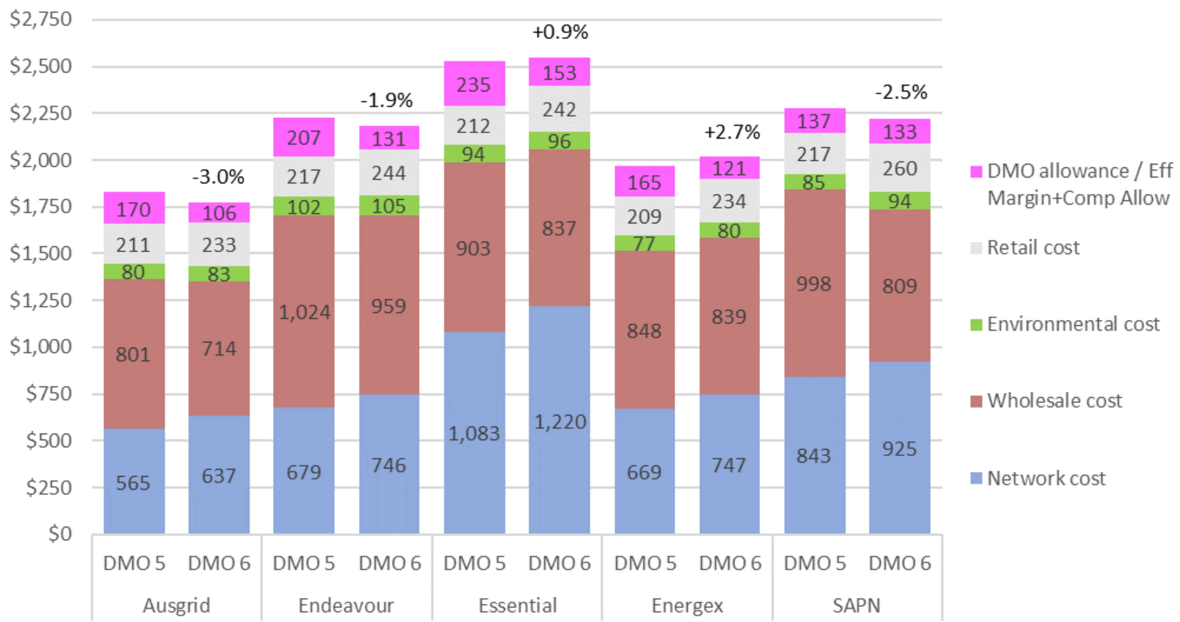


Figure D.2 Residential with CL, % change from DMO 5 (nominal)

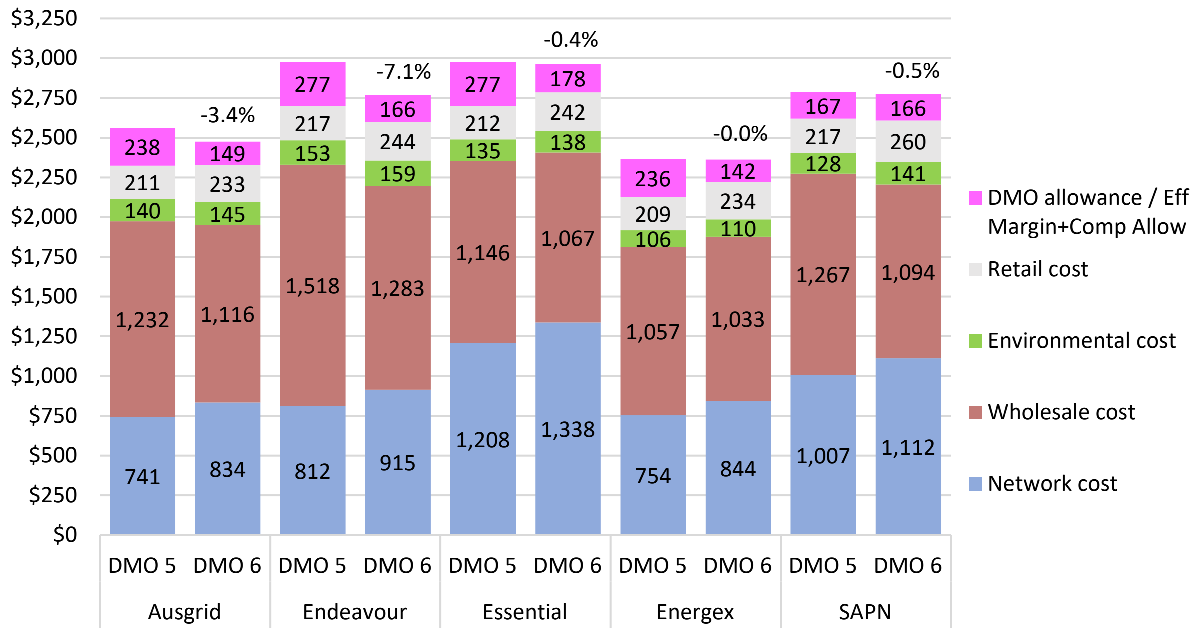
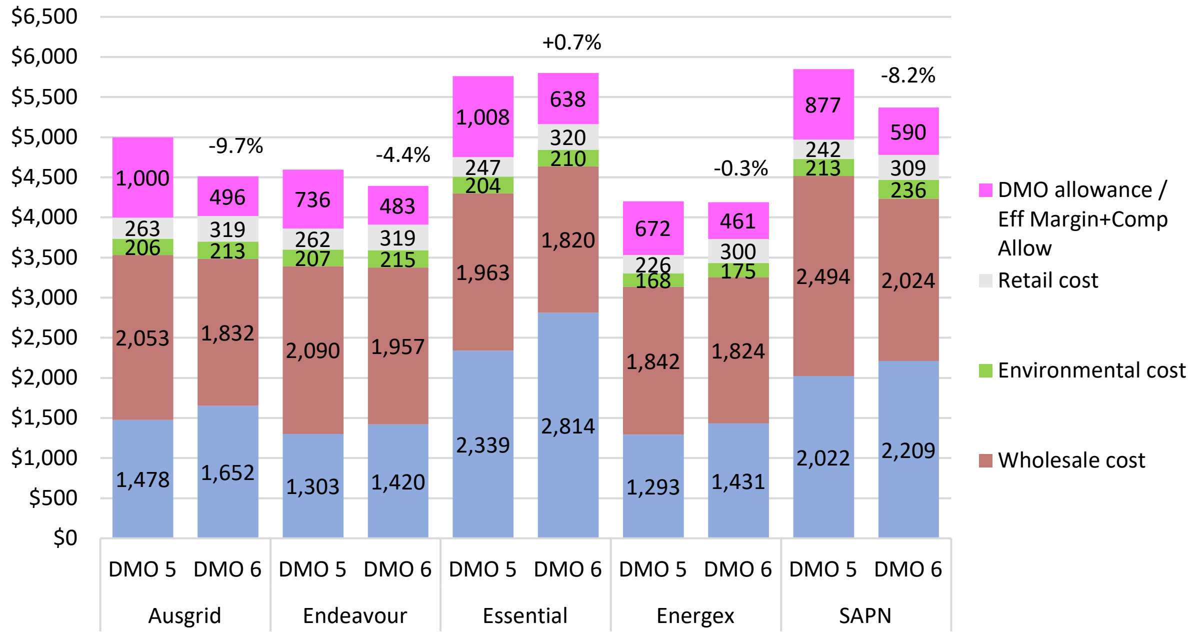


Figure D.3 Small business, % change from DMO 5 (nominal)



E. Market offers analysis at different usage amounts

Using the latest ACCC analysis of customer usage[171] and market offers from Energy Made Easy website (as at 25 January 2024) at different usage amounts, Tables B.1 and B.2 set out whether the market offer identified as the cheapest offer based on the DMO annual usage amount ("DMO identified cheapest offer") continues to be the cheapest offer at smaller and greater usage amounts for residential and small business customer.

Table E.1 Residential DMO identified cheapest offer analysis

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Proportion of customers for whom DMO identified cheapest market offer is cheapest	88.1%	82.3%	84.3%	92.3%	83.4%
Minimum usage where DMO identified cheapest offer is the cheapest (kWh)	1,400	2,000	2,700	2,100	2,200
Proportion of customers using less than minimum usage where DMO identified cheapest offer is the cheapest offer	3.7%	7.9%	15.0%	7.2%	14.2%
Maximum usage where DMO identified cheapest offer is the cheapest (kWh)	12,600	11,900	>21,000	>21,000	13,500
Proportion of customers using more than maximum usage where DMO identified cheapest offer is the cheapest offer	7.5%	9.1%	0.0%	0.0%	2.2%
Maximum further missed discount ($)	169.53	175.13	43.00	60.50	194.57
Maximum further missed discount as % of DMO identified cheapest market offer	2.7%	2.8%	7.6%	16.7%	37.6%
Customer-weighted average price ($)	2,072	2,103	2,488	1,863	2,216
Cheapest customer-usage-weighted average price	2,072	2,103	2,488	1,863	2,216
Ranking at ACCC median usage	1	1	1	1	1
Ranking at ACCC average usage	1	1	1	1	1

Note: percentages in rows 1,3 and 5 do not sum to 100%, because the ACCC reported usage distributions between 0 and 21,000 kWh cover approximately 99% of all customers. We have not considered market offer analysis for usage amounts above 21,000 kWh. Customer-weighted average price refers to the average annual price paid for an offer across all usage amounts presented in ACCC analysis, weighted by the proportion of the customer base corresponding to each usage amount.

[171] See ACCC, *Inquiry into the National Electricity Market, June 2023,* Appendix E – Supp. Tables A13.1-A13.4,A14.1-A14.4.

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Proportion of customers for whom DMO identified cheapest offer is cheapest	47.4%	51.3%	33.0%	71.1%	41.8%
Minimum usage where DMO identified cheapest offer is the cheapest (kWh)	5,900	5,200	9,500	3,300	5,000
Proportion of customers using less than minimum usage where DMO identified cheapest offer is the cheapest offer	52.6%	48.7%	67.0%	28.9%	58.2%
Maximum usage where DMO identified cheapest offer is the cheapest (kWh)	100,000	100,000	100,000	100,000	100,000
Proportion of customers using more than maximum usage where DMO identified cheapest offer is the cheapest offer	N/A	N/A	N/A	N/A	N/A
Maximum further missed discount ($)	323.88	317.31	337.59	48.06	426.16
% of maximum further missed discount	33.7%	49.3%	40.6%	11.9%	61.5%
Customer-weighted average price ($)	2,093	1,897	2,475	1,703	2,208
Cheapest customer-usage-weighted average price	2,089	1,897	2,388	1,703	2,205
Ranking at ACCC median usage	2	1	2	1	2
If ranking at ACCC median usage not the cheapest, amount this offer is over the actual cheapest at this usage ($)	8.95	n/a	102.89	n/a	45.85
Ranking at ACCC average usage	1	1	1	1	1

Note: ACCC reported usage distributions between 0 and 21,000 kWh cover approximately between 79.7% and 86.2% of all customers. We have assumed remaining customers consume between 21,000 and 100,000 kWh. Our analysis found that the DMO identified cheapest offer continues to be the cheapest offer up to 100,000 kWh (upper energy usage for DMO coverage). Customer-weighted average price refers to the average annual price paid for an offer across all usage amounts presented in ACCC analysis, weighted by the proportion of the customer base corresponding to each usage amount.