Australian Government

AUSTRALIAN ENERGY REGULATOR

2024–2025

Default market offer prices

Final determination

Important notice

The information in this publication is for general guidance only. It does not constitute legal or other professional advice. You should seek legal advice or other professional advice in relation to your particular circumstances.

The AER has made every reasonable effort to provide current and accurate information, but it does not warrant or make any guarantees about the accuracy, currency or completeness of information in this publication.

Parties who wish to re-publish or otherwise use the information in this publication should check the information for currency and accuracy prior to publication.

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

AER reference: 1715566734

Contents

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
ACOSS	Australian Council of Social Service
ACT	Australian Capital Territory
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
CARC	Costs to acquire and retain customers
CER	Clean Energy Regulator
CL	Controlled load
CPI	Consumer price index
DMO	Default market offer
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
DMO 7	Default market offer determination for 2025–26
DNSP	Distribution network service provider
ECA	Energy Consumers Australia
ESC	Essential Services Commission
GST	Goods and services tax
GJ	Gigajoule
kWh	Kilowatt-hour
LGC	Large-scale Generation Certificates
LRMC	Long run marginal cost
MWh	Megawatt-hour
NEM	National Electricity Market

Term	Definition
NSLP	Net system load profile
NSW	New South Wales
OTC	Over-the-counter
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
SE Queensland	South East Queensland
SCS	Standard Control Services
SRA	Settlements residue auction
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
STP	Small-scale Technology Percentage
TOU	Time of use
VDO	Victorian Default Offer
WEC	Wholesale energy cost

1 Executive summary

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

The DMO is an electricity price 'safety net' protecting consumers from unjustifiably high prices, while also allowing retailers to recover costs. It is the maximum price that a retailer can charge standing offer customers in New South Wales (NSW), South East Queensland (SE Queensland) and South Australia.[1] Standing offers are intended to provide a level of protection to customers who have not engaged, or cannot engage, in the retail electricity market.[2]

On 19 March 2024 we published a draft determination setting out our proposed approach and draft prices for DMO 6.[3] Each year the draft determination is subject to public consultation and stakeholder feedback. All feedback is considered and our decisions are reflected in this final determination. In making this final determination we have also observed price movements since DMO 5 and analysed specific market drivers leading to price changes and current cost-of-living pressures.

1.1 Price movements

The final DMO 6 prices for each customer type in each distribution region are set out in chapter 2.

Since DMO 5 there has been movement in the 2 largest cost components of the DMO – wholesale and network costs. We have observed wholesale costs easing off while network costs have increased. Similarly, increased retail operating costs were mostly offset in many regions by the lower allowances (including margins) that we allowed retailers. These movements have resulted in overall prices decreasing in NSW and South Australia, and increasing in SE Queensland.

In NSW, compared with DMO 5, residential customers without controlled load will see price decreases of around 1% (roughly 5% below forecast inflation). Customers with controlled load will see price decreases of 2% to 6% (6% to 10% below forecast inflation). Small business customers will see decreases of 1% to 8% (5% to 12% below forecast inflation).

In SE Queensland there are cost increases of around 4% for residential customers without controlled load (in line with forecast inflation) and 2% for residential customers with controlled load (2% below forecast inflation). Small business customers can expect a 1% increase (3% below forecast inflation). The Queensland and Australian governments have announced financial assistance with electricity bills that will more than offset these increases. More on government rebates and concessions can be found in section 1.2.

---

1 The cap on standing offer prices does not apply to customers on demand tariffs or small business customers on flexible or TOU tariffs.

2 Further information on standing offers and how the DMO protects customers on standing offers can be found in chapter 2.

3 AER, *Default market offer prices 2024–25: Draft determination*, 19 March 2024.

South Australian residential customers without controlled load will experience price falls of around 3% (7% below forecast inflation). Those with controlled load face decreases of around 1% (5% below forecast inflation). Small business customers will see a decrease of 9% (13% below forecast inflation).

From the DMO 6 draft determination to final, wholesale costs have fallen slightly for all customer types, while retail costs and environmental costs have all increased. Changes to network costs have varied, with increases across Ausgrid, Endeavour Energy and Energex customers, while Essential Energy and SA Power Networks have slightly decreased.

Further details on the market drivers of price outcomes are in section 1.3 and a comprehensive summary of state outcomes is included in Appendix E.

1.2 Cost of living

Electricity affordability remains a top cost-of-living issue for households. Many customers are facing challenges to absorb higher electricity prices in the current economic climate. Sustained and elevated consumer price index (CPI) levels highlight the increased cost pressures facing households and small businesses.

In recognition of this, the AER has placed increased weight on protecting consumers. For this decision we have adjusted the approach we use to calculate the retail allowance, separately calculating a retail margin and a competition allowance. Additionally, we have decided not to apply a competition allowance in DMO 6.

In determining whether to apply the competition allowance in future, we will consider cost-of-living pressures using CPI as our primary metric. Where quarterly CPI exceeds the Reserve Bank of Australia's target range on a material and sustained basis, we will not include the competition allowance in the DMO prices. We will also have regard to the health of retail market competition.

Government rebates and concessions also mean the effective price many consumers pay for electricity will be lower. The Australian and Queensland governments have announced electricity bill rebates for all households and some small businesses that will more than offset any increases. In addition, some households will be eligible for additional targeted support under schemes provided by the Queensland, NSW and South Australian governments.

Consumers can identify what forms of assistance they may be eligible for at www.energy.gov.au/rebates.

1.3 Market drivers of final DMO 6 prices

Wholesale market costs are one of the largest components of the DMO prices, typically comprising around 35–40% of the total price.

Since DMO 5, wholesale markets have stabilised significantly. Base futures contract prices have fallen by between 39% and 48% since the highs observed in 2022.[4] However, they remain higher than the levels seen in 2021 and early 2022. That is, they have stabilised at higher levels than in pre-DMO 5 years. The wholesale energy costs in DMO 6 have

---

[4] As at 3 May 2024 for 2024–25 (DMO 6) contracts in NSW, South Australia and Queensland only.

decreased by approximately 21% in South Australia and between 7% and 11% across NSW. In SE Queensland, costs have only decreased slightly (0.2%).

In addition to base contracts, our methodology includes the use of cap contracts to manage the risk that spot prices will spike over $300 per MWh. The Queensland region has the greatest reliance on these contracts during the summer months and these summer cap contracts have been trading at increased prices. For South Australia, these summer cap contracts have been trading at lower prices, which is a factor in why there is a significant disparity in wholesale cost outcomes for these regions. We also made adjustments to the way we handled customer load profiles, which are an important input into modelled wholesale costs. This has the greatest impact in South Australia.

The easing in wholesale prices has been offset by the pressures currently observed in network prices.

Network costs are the other major component of DMO prices. For residential customers network costs range from 34% (for Ausgrid) to 46% (for Essential Energy). For small business customers network costs range from 33% (for Endeavour Energy) to 48% (for Essential Energy).

During May 2024 the AER approved annual network tariffs for 4 of the 5 DMO distribution network service providers (DNSP) – Ausgrid, Endeavour Energy, Energex and SA Power Networks. Essential Energy has provided the AER with its final tariffs for 2024–25 and these have been included in the DMO price.

Across all 5 DNSPs there are increases for residential customers ranging from 6% (Essential Energy) to 16% (Ausgrid) and for small business customers ranging from 9% (SA Power Networks) to 19% (Ausgrid). Depending on the DNSP, the key drivers of these increases reflect market conditions and include adjustments for under-recovery of allowed revenue in prior years, increases in transmission costs, increases in inflation and interest rates, increases in incentive payments and jurisdictional schemes, and for the NSW networks, the NSW Roadmap contribution allocations. The AER is required to approve network tariffs where they are compliant with the National Electricity Rules and the relevant regulatory determination. The AER's regulatory determination for each DNSP seeks to balance the need for efficient and prudent investments in electricity networks, while at the same time ensuring consumers facing cost pressures pay no more than necessary for electricity services that meet their current and future needs.

Retail and other costs make up a smaller component of the DMO (around 12% for residential customers and 7% for small business). These costs are increasing because of the growing cost of managing bad debts and retailers ramping up efforts to roll out smart meters.

1.4 Our approach to DMO 6

To set the DMO each year, we consider how each cost component (network, wholesale, environmental and retail operating costs) has changed, as well as the retail margin and our consideration of what allowances should be provided. In our DMO 6 draft determination, we consulted on key aspects of our DMO methodology including:

- whether and how to change our approach to the customer load profile that is used to model wholesale costs given the availability of new interval meter data, increased solar PV penetration and data challenges in the Net System Load Profile (NSLP)

- whether a different wholesale forecasting method is required for South Australia given the low levels of Australian Securities Exchange (ASX) contract liquidity
- whether the approach to the retail margin and competition allowance is appropriate
- changes in smart meters installation costs in anticipation of a proposed 2025–2030 accelerated rollout in DMO regions.

We have summarised key aspects of our final determination approach below.

1.4.1 Wholesale costs

Historically we have relied on the Australian Energy Market Operator's (AEMO) NSLP and Controlled Load Profile to model the wholesale costs of retailers purchasing energy for residential and small business customers.

We have maintained our positions from the draft determination on load profiles used to model wholesale costs.

Due to data issues identified in the NSLP for the SA Power Networks and Energex regions, which arose from an interim algorithm adjustment made by AEMO as it adjusted to new settlement rules, we have adopted the midpoint of wholesale costs modelled based on the 2 alternative NSLP options. We recognise each NSLP option produces materially different results and consider that adopting the midpoint strikes a balance between allowing retailers to recover costs, while not resulting in an over-recovery from consumers. Because NSW was not impacted by the interim adjustment, we have maintained our approach from previous determinations to use AEMO's NSLP data as published for NSW regions.

DMO 6 marks the first determination where we have blended interval meter data in the load profiles used to determine the wholesale cost component. We have decided to exclude rooftop solar exports from the interval meter dataset used to create the blended load profiles. We consider that the DMO is a tariff that retailers charge consumers for imports (or consumption) and the load profiles used in the wholesale cost methodology should reflect this. Therefore, we consider it appropriate to model wholesale costs based on a retailer hedging against small customer consumption as opposed to the net of consumption and generation. Additionally, we have concerns that including exports would result in an over-recovery of wholesale costs because our methodology does not account for the value (both positive and negative) of solar exports against wholesale market outcomes and more sophisticated measures available to retailers to flatten their load profile. We consider that feed-in tariffs are also an important mechanism for retailers to manage the impact of rooftop solar. The DMO Regulations explicitly require us to disregard feed-in tariffs.[5] We acknowledge that the treatment of solar exports in the DMO is likely to become increasingly significant in the future due to the increasing uptake of solar PV and other consumer energy resources, and the acceleration of interval meter deployment. We expect that the NSLP (accumulation meter data) will become less relevant in determining the load profiles. Therefore, we will continue to assess this issue over time.

We have made other small adjustments to wholesale cost modelling assumptions, including adjustments to gas fuel price inputs, AEMO fees and AEMO prudential costs.

---

5 Section 8A of the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019.

1.4.2 Network costs

The draft determination used network costs based on updated estimates from each DNSP and included some placeholder inputs. The final determination uses the updated network tariffs from the final approved tariffs for Ausgrid, Endeavour Energy, Energex and SA Power Networks, and final proposed tariffs for Essential Energy.

1.4.3 Environmental costs

Environmental costs contribute to approximately 5% of the final DMO price (across all customer types).

The final determination has largely retained our existing approach. Environmental costs have increased in all regions in the last 12-month period by between 4% and 14% across all customer types.

1.4.4 Retail costs and margin

While only accounting for between 6% and 14% of the final DMO price (depending on which customer type), there have been increases in retail costs, ranging from 16% to 27% for residential customers and 24% to 37% for small business. This was driven particularly from smart meter rollout and bad and doubtful debt cost increases observed since DMO 5.

Our methodology for calculating retail costs remains consistent with the proposed approach from the draft determination. In response to feedback on our current approach to smart meters calculations, which did not reflect the NSW distribution regions' approaches to recovering metering costs following network tariff metering changes in NSW, we have adjusted that approach outlined in the draft determination.

Our consideration of smart meters for the final determination benefited from specific smart meter installation projections and data provided by 10 retailers after the draft determination.

We maintained our position from the draft determination to split the retail allowance into separate components. We have set the retail margins as a percentage of the DMO costs and also calculated a competition allowance. The retail margins have been set at 6% for residential customers and 11% for small business customers. By setting consistent margins for all regions this results in lower margins for most customers. Having regard to current economic conditions, cost-of-living pressures and energy affordability experienced by consumers, and as proposed in the draft determination, we have excluded the competition allowance for DMO 6.

We are confident that this approach will still allow retailers to recover their costs and make a reasonable profit.

2 DMO 2024–25 final prices

2.1 DMO final prices

The final DMO prices for 2024–25 for each customer type in each distribution region are set out in Table 2.1, which also shows the changes from DMO 5 in both real terms (that is, adjusted for forecast inflation) and nominal terms.

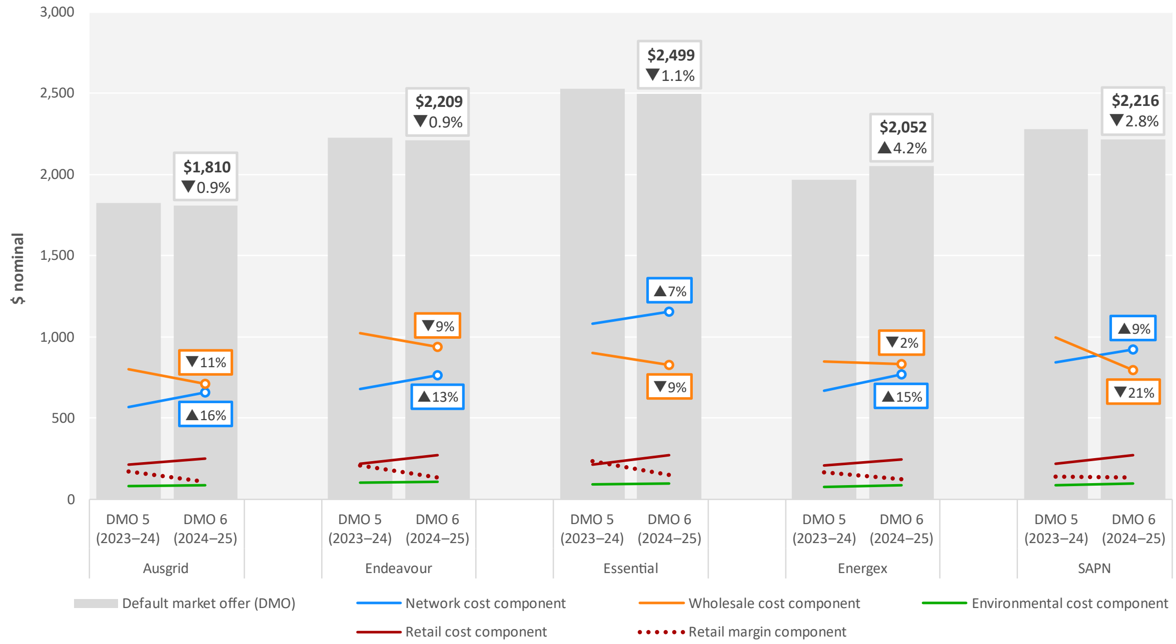
Table 2.1 DMO 2024–25 final determination prices, including changes from DMO 5 in nominal and real terms

Distribution region	Description	Residential w/out controlled load	Residential with controlled load	Small business w/out controlled load
Ausgrid	DMO price	$1,810	$2,495	$4,597
	For annual usage of	3,900 kWh	Flat rate 4,800 kWh + CL 2,000 kWh	10,000 kWh
	Change y-o-y	-$17 (-0.9%)	-$67 (-2.6%)	-$402 (-8.0%)
	Change y-o-y (real)	-$86 (-4.7%)	-$164 (-6.4%)	-$592 (-11.8%)
Endeavour Energy	DMO price	$2,209	$2,787	$4,407
	For annual usage of	4,900 kWh	Flat rate 5,200 kWh + CL 2,200 kWh	10,000 kWh
	Change y-o-y	-$19 (-0.9%)	-$190 (-6.4%)	-$191 (-4.2%)
	Change y-o-y (real)	-$104 (-4.7%)	-$303 (-10.2%)	-$366 (-8.0%)
Essential Energy	DMO price	$2,499	$2,918	$5,718
	For annual usage of	4,600 kWh	Flat rate 4,600 kWh + CL 2,000 kWh	10,000 kWh
	Change y-o-y	-$28 (-1.1%)	-$59 (-2.0%)	-$43 (-0.7%)
	Change y-o-y (real)	-$124 (-4.9%)	-$172 (-5.8%)	-$262 (-4.5%)
Energex	DMO price	$2,052	$2,400	$4,246
	For annual usage of	4,600 kWh	Flat rate 4,400 kWh + CL 1,900 kWh	10,000 kWh
	Change y-o-y	+$83 (4.2%)	+$37 (1.6%)	+$44 (1.0%)
	Change y-o-y (real)	+$8 (0.4%)	-$53 (-2.2%)	-$116 (-2.8%)
SA Power Networks	DMO price	$2,216	$2,746	$5,337
	For annual usage of	4,000 kWh	Flat rate 4,200 kWh + CL 1,800 kWh	10,000 kWh
	Change y-o-y	-$63 (-2.8%)	-$41 (-1.5%)	-$512 (-8.8%)
	Change y-o-y (real)	-$150 (-6.6%)	-$147 (-5.3%)	-$734 (-12.6%)

Note: Real comparisons with DMO 5 are based on RBA 2023–24 inflation forecast of 3.8% in its RBA May 2024 forecast for the 2 years ending June 2025.
CL: controlled load.
Usage is based on 365 days per annum (see Chapter 9).
Source: AER Default market offer 2024–25 cost assessment model.

Figure 2.1 shows the movement in the 2 key cost components (wholesale and network costs) since DMO 5. It illustrates the offsetting price movements between these costs, resulting in overall price reductions in NSW and South Australia. It also illustrates the outcome in Queensland, where wholesale costs have fallen less while network costs have grown. It similarly illustrates the increase in retail costs while margins (and other allowances) have declined in most regions. Further detail on each of these cost components is provided within the respective chapters in this report.

Figure 2.1 Composition of the default market offer (DMO 5 and DMO 6 (nominal terms))



Note: Comparison of cost components calculated for the 2023–24 and 2024–25 prices are for residential without controlled load (including GST) and are nominal.
Source: AER Default market offer 2024–25 cost assessment model.

3 Role of the AER

As independent regulator, the AER is 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 our functions and objectives we strive to maintain a healthy energy sector and promote the long-term interests of consumers.[6] We achieve this by exercising our functions under the National Energy Retail Law in a manner that contributes to achieving the national energy retail objective and is compatible with developing and applying consumer protections for small customers.[7] 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 –NSW (Endeavour Energy, Essential Energy and Ausgrid), SE Queensland (Energex) and South Australia (SA Power Networks).

3.1 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 (the model annual usage)[8]
- 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).[9]

The DMO price applies to residential and small business customers on standing offers in NSW, SE Queensland and South Australia.[10]

The Regulations set out that we must determine DMO prices for the following types of small customers, including:[11]

- residential customers – on flat rate or time of use (TOU) tariffs

---

6 AER, AER Strategic Plan 2020–25, Australian Energy Regulator, 14 December 2020.

7 National Energy Retail Law, S. 205.

8 Regulations, s. 16(1)(a), note that the AER is not required to determine the pattern of consumption in the case of small business customers.

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

10 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.

11 Regulations, s. 6.

- 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.[12]

The Explanatory Statement of the Regulations provides further details on each category, which includes customers with solar tariffs.[13]

To determine a reasonable annual price, the Regulations require us to have regard to a range of specific matters and costs.[14] These form the basis for the DMO cost stack methodology and align with the chapters of this report. The matters are:

- the prices electricity retailers charge for supplying electricity in the region to that type of small customer (considered when formulating the margins in Chapter 8)
- the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region (refer to Chapter 8).

The costs we must have regard to are:

- the cost of distributing and transmitting electricity in the region (refer to Chapter 4)
- the wholesale cost of electricity in the region (refer to Chapter 5)
- the cost of complying with the laws of the Commonwealth and the relevant state or territory in relation to supplying electricity in the region (included in Chapter 6 where these laws relate to costs associated with environmental obligations, but also covered by retail costs in Chapter 7 and some wholesale costs in Chapter 5)
- the cost of acquiring and retaining small customers, which is the case in all DMO regions (refer to Chapter 7)
- the cost of serving small customers (refer to Chapter 7).

We may also have regard to any other matter the AER considers relevant.

The Regulations also prescribe a mandatory industry code with DMO reference provisions requiring:[15]

- standing offer prices for small customers not to exceed a price determined by the AER[16]
- small customers to be told how a retailer's prices compare with the AER determined annual price[17]
- the most prominent price-related feature in an advertisement must not be a conditional discount and any conditions on other discounts are clearly displayed.[18]

---

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

13 Explanatory Statement, *Competition and Consumer Act 2010*, Competition and Consumer Legislation Amendment (Electricity Retail) Regulations 2020.

14 Regulations, s. 16(4).

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

16 Regulations s. 10.

17 Regulations s. 12.

18 Regulations s. 14.

Under these requirements, the DMO price acts as a ‘reference price’, against which customers can easily compare market offers. The Australian Competition and Consumer Commission (ACCC) is responsible for enforcement and compliance with these provisions.

3.2 Policy objectives guide the DMO

When the DMO Regulations were introduced, the government of the time also provided policy objectives.[19]

These policy objectives are the matters that we have considered are relevant when setting a reasonable price:[20]

In 2024, the Australian Government Minister for Climate Change and Energy provided a letter for the AER to consider under the flexibility afforded to us in the Regulations. The minister asked that the AER take into account broader economic conditions and how they impact energy producers and users, including acute periods of cost-of-living pressures such as the one currently being experienced. The minister’s letter made clear that this request is intended to be temporary to lessen the impacts of electricity bills on customers where the DMO applies and to be considered on balance with the original objectives.[21]

The NSW Minister for Energy urged the AER to consider an alternative approach to our margin methodology that avoids compounding customer bill impacts from energy price volatility, while still adhering to the DMO objectives. The minister suggested options to lower the retail margin and encouraged the AER to develop a long-term approach to margins that will provide clarity for governments, retailers and consumers for future determinations.[22]

The Queensland Minister for Energy and Clean Economy Jobs wrote to encourage the AER to consider measures to shield consumers from impacts to their household budgets in our approach to determining retail allowances. The minister suggested that we consider whether

19 The DMO objectives are set out in several sources including: the ACCC Retail Electricity Pricing Inquiry final report, June 2018; the Explanatory Statement accompanying the DMO Regulations, 2019; Treasurer’s and Minister for Energy’s request to the AER to develop a DMO, 22 October 2018; and the Minister for Climate Change and Energy’s letter, 2024.

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

21 Minister for Climate Change and Energy, *Submission to the DMO6 Issues Paper*, 2024.

22 The Hon Penny Sharpe MLC, Minister for Energy, *Submission to the issues paper*, 8 November 2023.

our approach to retailer headroom or lower margins could be changed while still allowing the DMO objectives to be met.[23]

The South Australian Department for Energy and Mining indicated that protecting consumers from unreasonably high prices should be the central objective that the AER considers when setting the DMO 6 prices for South Australia.[24]

We must meet the requirements in the Regulations in setting a reasonable price. We weigh up the policy objectives, including the advice we receive from governments on these, and economic conditions for consumers and energy retailers in considering how best to do this.

How the DMO differs from other state and territory price setting determinations

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), the ACT (Independent Competition and Regulatory Commission) and for regional Queensland (Queensland Competition Authority).

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.[25]

Embedded networks

The NSW Minister for Energy 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 responding to the Australian Government 2022 review of the Regulations, which included how to extend the price cap protection provided by the DMO to

---

23 The Hon Mick de Brenni, Minister for Energy and Clean Economy Jobs, *Submission to the issues paper*, 5 March 2024, and 29 February 2024; The Hon Mick de Brenni, *Submission to DMO 6 draft determination*, 9 April 2024.

24 SA Department for Energy and Mining, *Submission to DMO 6 issues paper*, 10 November 2023, pp. 2–3; South Australian Department for Energy and Mining, *Submission to DMO 6 draft determination*, 9 April 2024, p. 1.

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

embedded network customers.[26] We look forward to the outcome of the review of the Regulations.

3.3 Standing offer customers

The Australian Energy Market Commission (AEMC) and 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[23]
- have defaulted to a standing offer following the expiry of a market contract.[24]

Every retailer must have a standing offer and customers have the right to ask for one.[27]

However, for those with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms.[28] 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.[29]

---

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

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

28 National Energy Retail Law S. 22.

29 ACCC and AER, Joint Compliance Bulletin, May 2023.

In networks where the DMO applies, 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 the 3 largest retailers, referred to as 'Tier 1' retailers – AGL, EnergyAustralia and Origin Energy.

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		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		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		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		74,356 (22.2%)	26,053 (23.5%)	13,907 (15.8%)	**114,316 (21.6%)**

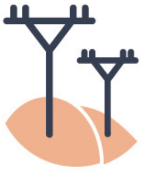
Note: SE Queensland figures are extrapolated from all Queensland by excluding Ergon customers. Other retailers have customers in regional Queensland so this figure is approximate. Standing offer customers calculated by subtracting market offer customers from total customers.
Source: AER Retail Market Performance update, Quarter 2 2023–24.

4 Network costs

In a retail electricity bill, network costs represent the cost of transporting electricity through transmission and distribution networks to a customer's premises.

Under the National Electricity Rules, the AER regulates network charges by approving the network tariffs that distribution network businesses set on an annual basis, which offer a range of tariff structures for each class of customer.

Network tariffs are typically comprised of 2 components:



Network Use of System charges
recovers the costs of providing transmission and distribution of electricity through network infrastructure, including costs of jurisdiction-specific schemes. For NSW DNSPs, it includes NSW Roadmap costs.

Metering (ACS) charges
relates to DNSP businesses' installation and maintenance of type 5 manually read interval meters and type 6 accumulation meters.

4.1 Draft determination

As noted in the DMO 6 draft determination, network businesses provided the AER with updated indicative network tariffs (in February 2024) for the 2024–25 year, which were used in the draft determination to calculate the indicative network costs for 2024–25.

That approach was necessary to enable us to consider the most up-to-date inflation forecasts, interest rates, cost of capital and other factors that drive network tariffs, due to those factors continuing to change since the indicative network tariffs for 2024–25 were submitted in the previous year.

In the draft determination, it was our position to use approved network flat rate tariffs for 2024–25 for the final DMO 6 price calculation. We considered that this approach remains appropriate for DMO 6, given most customers are on flat rate tariffs and that altering our approach would add complexity and reduce transparency without providing major benefits to stakeholders.

The draft determination network tariffs for NSW DNSPs included a contribution recovery for the NSW Roadmap costs. As a result, we did not need to separately estimate NSW Roadmap costs for the DMO 6 draft determination (as we did for 2023–24) or in this DMO 6 final determination.

4.2 Stakeholder views

Of the draft determination submissions relevant to the network costs component of DMO 6, no issues were raised with the methodology used by the AER in determining those network costs. Specifically, 1st Energy, Energy Locals and Origin Energy were supportive of the approach taken by the AER.[30]

Alinta Energy expressed concerns that as the use of flat rate tariffs declines, driven by the increase in the use of time-of-use tariffs, retailers may bear the financial risk burden of this change.[31]

4.3 Final determination

The final determination for 2024–25 is based on updated network costs from the final approved tariffs for SA Power Networks, Energex, Ausgrid and Endeavour Energy, and the final proposed tariffs for Essential Energy. This is done in accordance with the National Electricity Rules (clause 6.18.8).[32]

In response to Alinta Energy's point (section 4.2 above), as we discussed in the draft determination, due to the current inability to identify and remove controlled load data in the Market Settlement and Transfer Solutions dataset, the DMO 6 final determination will continue to base the DMO network costs for customers on flat rate tariffs only. 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.

Consistent with our draft determination, and as mentioned in section 4.1, we have used the approved (or final proposed[33]) flat rate network tariffs to calculate the DMO network component in each of the 5 distribution regions.

These costs have varied from the indicative network tariffs that were the basis of the draft determination network component. The final network costs for DMO 6 were:

- 2.5% to 6.3% higher than our DMO 6 draft determination estimates, depending on the customer type, for the Ausgrid (NSW) region
- 2.1% to 2.6% higher for the Endeavour Energy (NSW) region
- 2.5% to 5.3% lower for the Essential Energy (NSW) region
- 2.8% to 3.2% higher for the Energex (SE Queensland) region
- 0.1% to 0.6% lower for the SA Power Networks (South Australia) region.

Key drivers for these variations include the most recent final revenue determinations for NSW distribution businesses, cost pass-throughs, efficiency incentive payments and updated transmission costs and final NSW Roadmap costs.

---

30 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 7; Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 2.

31 Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

32 National Electricity Rules, clause 6.18.8.

33 At the time of finalising this DMO 6 final determination, the annual tariffs for Essential Energy had not been approved by the AER. Therefore, the final proposed tariffs relevant to the DMO are used.

Specific drivers for increases in network costs from DMO 5 to DMO 6, by order of magnitude, include:

- Ausgrid: increases in transmission costs, jurisdictional scheme costs including the NSW Roadmap, inflation, the revenue path in our regulatory determination and increases in incentive scheme payments.
- Endeavour Energy: increases in jurisdictional scheme costs including the NSW Roadmap, the revenue path in our regulatory determination, increases in transmission costs and inflation, partially offset by the return of previous over-recoveries of allowed revenue.
- Essential Energy: while not yet approved, prices in the Essential Energy network are driven by the similar factors to Endeavour Energy network. These are increases in transmission costs, increases in jurisdictional scheme costs including the NSW Roadmap, inflation, the revenue path in our regulatory determination, partially offset by the return of previous over-recoveries of allowed revenue.
- Energex: higher inflation/rate of return update, increases in incentive scheme payments, increases in transmission cost and jurisdictional scheme costs, recovery of previous under-recoveries in jurisdictional scheme costs; offset by the return of previous over-recoveries of allowed revenue.
- SA Power Networks: increases in recovery of previous under-recoveries, increases for inflation/rate of return update and the River Murray cost pass through is offset by the AER's decision to return over-recovered allowed revenue to customers and impacted by decreases in incentive scheme payments and jurisdictional scheme costs.

The network tariffs that are used to assess network costs for each DNSP are set out in Table 4.1. The network costs resulting from these network tariffs are shown in Table 4.2 and included in the DMO 6 charts in Appendix D. The DMO 6 price calculation model shows the detailed calculations and is published alongside the final determination.

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 Energy	Residential Flat tariff –N70	Controlled load 1 N50 Controlled load 2 N54	General Supply Block Tariff N90
Essential Energy	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
SA Power Networks	Residential Single Rate RSR (SR)	Residential Single Rate RSR (controlled load)	Business Single Rate BSR

Source: AER approved network tariffs.

Total network cost components for the 2024–25 DMO 6 are set out in Table 4.2, together with the comparative costs used for the 2023–24 DMO 5.

Table 4.2 Total network costs for 2023–24 and 2024–25 ($ nominal, incl. GST)

Distribution region	Tariff	2023–24	2024–25	Change year-on-year	
Ausgrid	Residential flat rate	$565	$657	$91	16.2%
	Residential controlled load	$741	$855	$114	15.4%
	Small business 10,000 kWh	$1,478	$1,756	$279	18.9%
Endeavour Energy	Residential flat rate	$679	$765	$86	12.7%
	Residential controlled load	$812	$934	$122	15.1%
	Small business 10,000 kWh	$1,303	$1,454	$151	11.6%
Essential Energy	Residential flat rate	$1,083	$1,155	$72	6.7%
	Residential controlled load	$1,208	$1,276	$68	5.7%
	Small business 10,000 kWh	$2,339	$2,743	$404	17.3%
Energex	Residential flat rate	$669	$768	$98	14.7%
	Residential controlled load	$754	$870	$116	15.4%
	Small business 10,000 kWh	$1,293	$1,475	$182	14.1%
SA Power Networks	Residential flat rate	$843	$922	$80	9.4%
	Residential controlled load	$1,007	$1,105	$98	9.7%
	Small business 10,000 kWh	$2,022	$2,206	$185	9.1%

Note: Total network costs contain a fixed and variable component and are a function of usage.
Source: AER Default market offer 2024–25 cost assessment model.

5 Wholesale energy costs

5.1 Draft determination

5.1.1 Load profile assumptions

Historically we have relied on the Net System Load Profile (NSLP) and Controlled Load Profile to model the wholesale costs borne by retailers purchasing energy for residential and small business customers. In our draft determination, we made the following 2 changes to our methodology for calculating wholesale costs:

- we used the midpoint between 2 datasets for the NSLP while also incorporating interval meter data
- we excluded solar exports from the interval meter data.

We identified issues with the standard NSLP dataset in the Energex and SA Power Networks regions, which 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. This led to an unusually flat load profile. AEMO removed the interim adjustment in October 2023. ACIL Allen also produced an adjusted NSLP dataset based on a sample of data around the time AEMO introduced the interim adjustment. We released an additional consultation paper in February 2024 which summarised this issue and sought stakeholder feedback on the alternative NSLP options.[34]

The alternative NSLP options produced materially different results. To ensure that neither retailers nor consumers were disproportionately burdened by this transitory data issue, for the DMO 6 draft determination we modelled wholesale energy cost (WEC) estimates using both NSLP datasets and adopted the midpoint of the 2 results as the final WEC input for DMO 6. Because NSW was not impacted by AEMO's interim adjustment, we continued using AEMO's non-adjusted NSLP to model WEC estimates for NSW regions, without using the ACIL Allen adjusted NSLP.

For all regions, including Energex and SA Power Networks, we also included interval meter data to create a blended load profile. We considered this would more accurately account for the increasing number of interval meters being installed across residential and small business consumers. Due to concerns that solar exports would overstate the costs of the daytime carve-out for retailers, exports were excluded from the blended load profile.

Other load profile assumptions

The DMO 6 draft determination maintained:

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

We considered that applying a single load profile to both residential and small business customers and incorporating interval meter data to create a blended profile is representative of the customer load shape served by the DMO.

---

34 The AER's consultation paper on NSLP options provides additional background on the data issues identified.

For the NSW load profiles, we recognised that a single load profile approach is applied in practice by some retailers but considered that adopting this for the DMO could result in inadvertently benefiting or burdening customers within a given distribution network. Therefore, we maintained separate load profiles for each distribution network in NSW. We also noted that this would align with our approach to have separate network charges for each region.

5.1.2 South Australian wholesale methodology

Use of confidential contract information

The DMO 6 draft decision 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.

To investigate concerns about market liquidity in South Australia, we sought additional contract market data from market participants in South Australia to assess whether ASX data in isolation provides an accurate reflection of the hedging costs a retailer faces. The data request included confidential over-the-counter (OTC) contract data.

We found that for OTC contracts with terms aligned with ASX traded contracts, the OTC data provided by market participants did not indicate a material difference in price. Additionally, we noted that the confidential contract information confirmed that base futures (swaps) and caps are still the most used contract types in South Australia. Therefore, we continued to base the wholesale cost methodology on the publicly available ASX data only.

Despite this finding, we noted in the DMO 6 draft determination that we continue to hold concerns about the low levels of traded volumes for DMO 6 products in South Australia. Although no changes were made to our methodology, we stated we would continue to seek additional data that assists us in ensuring the wholesale cost is reflective of operating in the South Australian market.

Other methodologies considered

The DMO 6 draft decision investigated how an initial long-run marginal cost (LRMC) estimate for South Australia can be used as a comparative data point against our current wholesale cost methodology.

The LRMC analysis was undertaken by ACIL Allen and based on the latest AEMO Integrated System Plan ‘Step Change’ scenario data, modelling both greenfield (creating generation to meet supply at least cost) and brownfield (based on current generation fleet) options. This was then scaled down to the South Australian load profiles to produce a WEC estimate. The outcome of the analysis showed that the WEC estimates produced from both scenarios were slightly lower for 2024–25 than those resulting from the current wholesale cost methodology.

We found that the LRMC analysis along with OTC data provides a helpful datapoint in the context of low contract market liquidity but decided to retain our current wholesale cost methodology for DMO 6 given the congruence between OTC and ASX traded contract prices.

The draft decision also did not incorporate the use of Victorian contracts or Settlement Residue Auctions (SRAs) in the modelling of wholesale costs for South Australia. We consider that inter-regional management of an SRA position is difficult because of the non-firm nature of SRAs and that we also did not observe a large number of Victorian futures contracts reported by South Australian participants in the first tranche of our collection of contract data.

We also stated our concerns with the use of broker curves as suggested by retailers and concluded that these sources of data are unlikely to be transparent and representative of market conditions.

5.1.3 Other wholesale cost issues

The DMO 6 draft determination discussed the treatment of a range of other aspects of the wholesale cost methodology:

- **75th vs 95th percentile:** We maintained our approach of using the 75th percentile of wholesale modelled price outcomes. We considered that the 75th percentile strikes the right balance between retailers recovering the efficient costs for providing their services and the allocation of risks to consumers.
- **Length of the book build period:** We maintained our approach for the hedge book build period, which involved using all available trades on the ASX relevant to the DMO 6 period. While hedging strategies will differ across retailers, we considered the current approach that smooths price movements in the DMO best captures all contract price movements for the relevant DMO 6 contracts.
- **ASX options:** We maintained our treatment of options from previous DMO determinations, which included 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. Overall, we considered ASX options a valuable indicator of the overall cost of energy, noting that retailers commonly use options as a hedging tool.
- **Changes to coal and gas caps:** We stated that our modelling approach for the DMO 6 period would reflect recent developments in wholesale coal and gas price control regimes. For the draft determination, the wholesale cost methodology for DMO 6 assumed that coal price caps in NSW and Queensland would be rescinded at the end of the 2023–24 financial year, and that gas prices would be capped at $12 per gigajoule (GJ).

5.2 Stakeholder views

5.2.1 Load profile assumptions

Energex and SA Power Networks NSLP options

Submissions from retailers did not support our approach taken in the draft determination, to model wholesale costs using both the AEMO non-adjusted NSLP and ACIL Allen adjusted NSLP, then adopt the midpoint of the 2 as the final WEC input for DMO 6.

Issues raised by retailers focused on including the NSLP as published by AEMO when modelling wholesale costs. The submissions considered that because the adjustment made by AEMO to the NSLP data had now been removed, this NSLP data would not result in a broadly reflective load shape for the DMO 6 period (2024–25).[35]

EnergyAustralia, Energy Locals and the AEC questioned how the AEMO NSLP could be used due to known flaws in the dataset, while ENGIE suggested if the midpoint is used in the final determination, greater weight should be placed on the modelled outcomes of the ACIL Allen adjusted NSLP. Additionally, the AEC noted adopting the midpoint of the 2 datasets may cause a step change for DMO 7, and requested the AER provide notice on how this will be handled.

Overall, retailers who commented on this issue preferred solely using the ACIL Allen adjusted NSLP data because it would more closely reflect the load shape of a retailer given AEMO's adjustment has been removed. This feedback was echoed during workshops with retailers.

Conversely, the Queensland Minister for Energy and Clean Economy Jobs considered that the AEMO NSLP should be used due to the data being public, transparent and likely to have driven retailers' hedging strategies.[36] Frontier Economics, who were engaged by the Queensland Minister, agreed that both NSLP options were balanced in terms of merits and disadvantages. However, Frontier Economics considered there is a potential inconsistency between retailers determining a hedging position based on the adjusted NSLP, which was only evident to retailers after the DMO 6 draft determination was released, and the assumed book build period of 2 to 3 years.[37]

While consumer advocacy groups did not directly comment on the NSLP in their submissions to the draft determination, we note the Public Interest Advocacy Centre (PIAC) and South Australian Council of Social Service (SACOSS) supported using the AEMO NSLP in their joint submission for the NSLP consultation in February 2024. The South Australian Department for Energy and Mining, Department of Climate Change, Energy, the Environment and Water and Queensland Department of Energy and Climate also supported using the AEMO NSLP.[38]

Adopting a blended load profile

Several retailer submissions supported the inclusion of interval meter data to create a blended load profile because they considered a load profile based on both accumulation and interval meters would be a more accurate reflection of a retailer's load shape.[39] However, a

---

35 AEC, *Submission to DMO 6 draft determination*, 13 April 2024, p. 4; AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 1; EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, p. 13; Engie, Submission to *DMO 6 draft determination*, 9 April 2024, pp. 1–2; Energy Locals, *Submission to DMO6 draft determination*, 9 April 2024, p. 2; Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 3.

36 Queensland Minister for Energy and Clean Economy Jobs, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

37 Frontier Economics, *Review of retail wholesale energy cost methodology*, 8 April 2024, pp. 3–4.

38 PIAC/SACOSS, *Joint submission to NSLP approach consultation paper*, 20 February 2024, p. 2; South Australian 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. 2; The Hon Mick de Brenni, *Submission to the DMO 6 issues paper*, 5 March 2024.

39 AEC, Submission to DMO 6 draft determination, 13 April 2024, p. 5; Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 3; Energy Locals, *Submission to DMO 6 draft determination*, 12 April 2024, p. 2; AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

number of retailer submissions did not support the approach in the draft determination to exclude solar exports from the load profiles.[40]

Energy Locals, 1st Energy and Momentum Energy all highlighted the impact solar exports had on load profiles and its relationship to the wholesale spot market during times of negative prices. These submissions noted that there are times when a retailer's load can be negative (when exports from customers with solar PV exceed the consumption of non-solar customers), which when combined with a negative spot price, results in a cost to a retailer. Further, they noted that these outcomes are difficult or expensive to hedge against, which ultimately increases a retailer's risk profile.

Origin Energy and Energy Locals considered including exports would likely better reflect a typical retailer's small customer load. The AEC suggested exports should be included because it would be more reflective of a representative retailer. They further noted that the wholesale cost methodology should uphold the principles of incentive-based regulation in that retailers may be rewarded by outperforming the benchmark set through the DMO determination.[41]

The DMO 6 draft determination raised concerns that including exports without also accounting for load shifting strategies would result in an over-recovery of costs from consumers, but also sought options and evidence from stakeholders on how the treatment of exports could be adjusted. Alinta Energy agreed that the DMO should account for counterstrategies for solar exports but noted that these measures would not fundamentally alter the impact of solar exports. While Energy Locals is supportive of these types of initiatives, it questioned the economics of load shifting strategies, especially for smaller retailers.

We note retailers were the only stakeholders to comment on the treatment of solar exports in the blended load profiles in submissions to the draft determination.

Other load profile assumptions

Limited feedback was received from stakeholders on other aspects relating to load profiles. Origin Energy supported the decision to maintain separate load profiles for each distribution network in NSW and EnergyAustralia supported the consistency in maintaining a single load profile for both residential and small business customers.[42]

5.2.2 South Australian wholesale methodology

Use of confidential contract information

Submissions that addressed the collection of OTC contract market data were supportive of us continuing to collect data for South Australia to benchmark against ASX trade data. Origin

40 Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 3; Energy Locals, *Submission to DMO 6 draft determination*, 12 April 2024, p. 2; Momentum Energy, *Submission to DMO 6 draft determination,* 10 April 2024, p. 2; Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 1–2; 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

41 AEC, *Submission to DMO 6 draft determination*, 13 April 2024, pp. 4–5.

42 Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3; EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, p. 13.

Energy noted that benchmarking against the OTC data demonstrates that the methodology of using ASX data remains appropriate.[43]

Other methodologies considered

Origin Energy supported our decision to not incorporate bespoke contracting products including SRA units in modelling wholesale costs for South Australia. It also recommended the LRMC analysis only remain as a comparative data point, because there is a risk this approach could result in a WEC estimate that is not representative of actual retailer costs.[44]

5.2.3 Other wholesale cost issues

75th vs 95th percentile

Retailers were consistent in their recommendation to the AER to return to the 95th percentile of wholesale modelled price outcomes. Alinta Energy, 1st Energy, ENGIE and Origin Energy submitted that the 95th percentile of wholesale modelled price outcomes most accurately reflects the risks facing a prudent retailer hedging against spot market outcomes in the NEM.[45]

ENGIE, Momentum Energy and 1st Energy considered volatility in the wholesale electricity market provides a basis to return to the 95th percentile.[46] Origin Energy also submitted that adopting a higher percentile estimate minimises the risk of underestimating the WEC when taking other aspects of the decision into account that could lead to underestimation, such as the midpoint approach for the NSLP and removal of the competition allowance.[47]

Alinta Energy and Momentum Energy also recommended the AER undertake a review of the optimum percentile to be used in the wholesale cost methodology.[48]

In contrast, in their joint submission, PIAC, SACOSS, and the Australian Council of Social Service (ACOSS) supported the AER maintaining the current approach of using the 75th percentile estimate of modelled cost outcomes. The Queensland Minister recommended lowering the percentile to the median (50th percentile), noting the approach of the ESC.[49]

The Queensland Minister further commissioned a consultant note from Frontier Economics, which suggested a shift to the 50th percentile might provide a better balance between

---

43 ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 12 April 2024, p. 8; South Australian Department for Energy and Mining, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 6.

44 Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 6.

45 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 6–7.

46 ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Momentum Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Rystad Energy, Trouble down under: Australia’s electricity market is the most volatile in the world, 23 October 2023.

47 Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 6–7.

48 Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2; Momentum Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

49 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 10 April 2024, p. 8; Queensland Minister for Energy and Clean Economy Jobs, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

retailers recovering their efficient costs and the allocation of risks to consumers.[50] Frontier Economics argued that using the 50th percentile would mean that over the long term, retailers would be expected to recover their efficient costs rather than an amount higher than their efficient costs (as they would with WEC estimates based on the 75th or 95th percentile).

Length of book build period

Origin Energy supported the existing book build process, which occurs over a 2 to 3-year period, whereas the Queensland Minister recommended shortening the length of the book build period from 3 years to be more reflective of actual hedging practices of retailers.[51] The Queensland Minister referenced the ACCC's Inquiry into the National Electricity Market report, which observed that the average contract time horizon for large and small retailers is consistently less than 2 years and often less than one year.[52]

Frontier Economics, on behalf of the Queensland Minister, highlighted the common practice for retailers to contract over shorter periods, particularly smaller retailers.[53] They explained that a shorter book build period would be more reflective of retailer hedging practices and result in customers being exposed to retail prices that are more reflective of current wholesale prices. They caveated this with the recommendation that the AER would need to signal this change to the market prior to implementation so retailers can adjust contracting strategies accordingly, because DMO determinations may influence retailer contracting behaviour.

Changes to coal and gas caps

Origin Energy suggested removing the assumed fuel price cap of $12 per GJ for combined cycle gas plants because exemptions made under the new Gas Market Code could result in fuel costs exceeding the cap over the DMO 6 period. It also recommended developing scenarios to allow for the impact of variable coal and gas prices on modelled spot prices to be tested.[54]

Other wholesale cost modelling assumptions

Several submissions questioned other specific inputs into the wholesale cost modelling.

- **AEMO fees:** EnergyAustralia noted that AEMO has adjusted its approach to fees by splitting fees between a fixed and variable component, and considered the DMO wholesale cost methodology should capture this change. Additionally, it noted that the methodology used in the draft determination to convert the fixed component to variable used total energy consumption across the entire NEM, including commercial and industrial customers. EnergyAustralia considered this unsuitable for a DMO determination for residential and small business customers and likely to result in an under-recovery for retailers.[55]

---

50 Frontier Economics, *Review of retail wholesale energy cost methodology*, 8 April 2024, pp. 1–2.

51 Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 6; Queensland Minister for Energy and Clean Economy Jobs, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

52 ACCC, *Inquiry into the National Electricity Market, December 2023 Report*, 1 December 2023, p. 91.

53 Frontier Economics, *Review of retail wholesale energy cost methodology*, 8 April 2024, pp. 4–5.

54 Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 3–5.

55 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 11–12.

- **AEMO prudential requirements:** Energy Locals noted an inconsistency between AEMO's definition of the winter period (April to August) and the calculation of prudential costs in the wholesale cost methodology, which uses May to August. Additionally, Energy Locals noted a change in its own AEMO forecast daily usage volumes that are factored into the calculation of prudential requirements. It considered the changes resulted in volumes for April being similar to those of a June/July winter load and recommended that this is accounted for in the calculation of prudential costs in the wholesale cost methodology.[56]
- **Hedging strategy:** Origin Energy reiterated its position that the hedging strategy adopted in the wholesale cost methodology with a lower base and higher cap contract position does not reflect the portfolio of a prudent retailer. It considered this is likely due to fixed fuel cost inputs in the modelling and that a portfolio closer to DMO 4 (with a relatively greater proportion of baseload contracts) would be more suitable. It recommended testing the sensitivity of the WEC against a sustained high pool price scenario and a low cap contract payout scenario.[57]
- **Compensation costs:** Origin Energy agreed known AEMO and AEMC compensation costs should be passed through the DMO wholesale component.[58]
- **Unaccounted for energy:** 1st Energy noted that the draft determination did not make an allowance for costs associated with unaccounted for energy.[59]
- **Wholesale spot price modelling:** Origin Energy considered that the spot price modelling undertaken by ACIL Allen does not reflect the range of wholesale price scenarios a retailer could be exposed to, which is a result of fixing fuel prices across all modelled simulations.

Other responses received from stakeholders

Submissions from Energy Consumers Australia (ECA) and PIAC/SACOSS/ACOSS noted that, while wholesale costs in the DMO 6 draft determination decreased from DMO 5, DMO prices have remained above levels prior to the market events of 2022. SACOSS was concerned about the impact of wholesale costs on low-income households in South Australia resulting from peaky demand and low liquidity levels.[60]

While PIAC/SACOSS/ACOSS did not directly comment on the length of the book build period, they raised concerns with the stark disparity between the low wholesale spot prices in South Australia and the high wholesale costs captured in the DMO, which in part is a result of the book build period length.[61]

---

56 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 7.

57 Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 5–6.

58 Origin Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 6.

59 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

60 ECA, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3; PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 12 April 2024, p. 8.

61 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 12 April 2024, p. 8.

The Queensland Energy Minister encouraged the AER to further enhance transparency in the wholesale cost methodology by publishing data to facilitate greater replicability and accountability.[62]

We also received a submission from Mr. Nick Roucek, who considered the DMO 6 draft determination to be an insufficient response to wholesale price moderations observed since 2022.[63]

5.3 Final determination

Our methodology and reasoning behind our approach to determine wholesale costs based on stakeholder feedback is detailed below.

5.3.1 Load profile assumptions

Energex and SA Power Networks NSLP options

For Energex and SA Power Networks regions, we have maintained our approach to model separate WEC estimates using AEMO's non-adjusted NSLP and ACIL Allen's adjusted NSLP, and adopt the midpoint of the 2 results as the final WEC input for DMO 6.

We agree with retailer feedback that use of the ACIL Allen adjusted NSLP may better reflect the load shape a retailer would face during the DMO 6 period. However, we hold concerns that the adjusted dataset is peakier in some respects than the load shape that has emerged since AEMO removed its interim adjustment, potentially resulting in an over-recovery of costs from consumers. An over-recovery of costs could also arise because the NSLP data includes exports that cannot be separated out, and ACIL Allen's adjustment seeks to return the load profile shapes closer to shape of the NSLP prior to the implementation of 5-minute settlement. We also note it is less transparent and does not reflect the assumed basis of settlement used for the majority of the book build period.

The non-adjusted dataset upholds consistency with previous DMO determinations, is transparent and reflects the assumed basis of settlement used for majority of the book build period. However, we recognise it does not reflect the settlement approach that is likely to be used in the future, and the underlying flatter load shape may result in an under-recovery of costs for retailers.

Overall, we view the options as evenly balanced in terms of merits and disadvantages and still consider it appropriate to adopt the midpoint approach for DMO 6 in the context of imperfect data sources. Regarding the AEC's submission on the potential step change in wholesale costs for DMO 7, we consider adoption of the midpoint will assist to counter the potential step change. We also note that AEMO is expected to make further adjustments to resolve the data issues in the NSLP in September 2024, which may impact the shape of the load profile in future determinations.

62 Queensland Minister for Energy and Clean Economy Jobs, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

63 Nick Roucek, *Submission to DMO 6 draft determination*, 19 March 2024, p. 1.

Table 5.1 WEC results of differing load profile options

Distribution region	Load profile option	Resulting wholesale energy costs (per MWh)
Energex	AEMO non-adjusted NSLP	$140.54
	ACIL Allen adjusted NSLP	$160.64
	Midpoint	$150.59
SA Power Networks	AEMO non-adjusted NSLP	$134.55
	ACIL Allen adjusted NSLP	$163.60
	Midpoint	$149.07

Source: ACIL Allen.

For all regions in NSW (Endeavour Energy, Essential Energy and Ausgrid), we have continued to use the NSLP data in alignment with previous DMO determinations because NSW was not impacted by AEMO's interim adjustment.

Adopting a blended load profile

We have decided to continue blending interval meter data in the load profiles used to determine wholesale costs for DMO 6. Both the adjusted and non-adjusted load profiles used to estimate the WECs have been blended with interval meter data in Energex and SA Power Networks regions. For NSW regions, the NSLP and interval meter data has also been blended.

We have not included small customer solar exports in the interval meter dataset that has been used to create the blended profiles. As set out in the draft determination, we consider excluding exports results in WEC estimates that are reasonably reflective of wholesale costs retailers are likely to face across the DMO 6 period, without resulting in an over-recovery of costs from consumers.

Because this was a key issue raised by retailers during consultation, we asked ACIL Allen to provide the AER with its view on how solar exports should be treated within the load profiles. In their note to the AER, ACIL Allen considered solar exports should be excluded because the DMO seeks to set a tariff for customer imports, and the demand profiles used in the wholesale cost methodology should reflect the profile used by retailers to bill their customers for consumption imported from the grid. ACIL Allen undertook additional analysis that highlighted the potential net financial benefit to a retailer in dollar terms if the WEC was based upon a load profile that included exports, but the retailer charges that amount to customers based only on import volumes (noting the DMO applies to imports only). Additionally, they noted that costs for retailers associated with solar exports when small customers export during negative price intervals should be managed by retailers when setting a feed-in tariff.[64]

We also engaged Frontier Economics to provide an additional view on how solar exports should be treated within the load profiles. In their note to the AER, Frontier Economics

64 ACIL Allen, *Wholesale energy costs and rooftop PV exports: Interaction of DMO WEC estimation methodology with solar FiTs*, 21 May 2024.

considered that solar exports should not be included because the DMO seeks to set a tariff that applies only to customers' imports from the grid, or consumption. They noted the relationship between customers' exports to the grid and a retailer's settlement payments to AEMO whereby a retailer is paid by AEMO for customers' exports when spot prices are positive, and the reverse during times when spot prices are negative. Frontier Economics shared ACIL Allen's view that settlement payments by retailers to AEMO for customers' exports when prices are negative can ultimately be reflected in the feed-in tariff set by a retailer. Additionally, they considered that the load a retailer hedges against is different from the load that should be used to estimate the WEC for the DMO. They noted that while a retailer can hedge against its entire portfolio to potentially achieve portfolio benefits, different customer types and loads within a portfolio likely have different costs to serve and it is this cost to serve that is relevant for the DMO.[65]

We agree with the views of Frontier Economics and ACIL Allen's analysis demonstrating the potential net financial benefit for retailers arising from including solar exports and that the DMO is ultimately a tariff for imports. We also note that the cost exposure associated with negative price intervals can be managed through feed-in tariffs. However, the Regulations state that we must disregard any amount a retailer pays in feed-in tariffs.[66]

We recognise the cost exposure for retailers when exports from customers with solar PV exceed the consumption of non-solar customers (meaning a retailer's load is negative) during negative price intervals, as expressed in retailer submissions. To investigate the materiality of these events, we assessed exports in the interval meter dataset against historical spot market outcomes, using South Australia as a test case. Our analysis highlighted that the value of solar exports is highly dependent on spot market outcomes. When day-time spot market prices are positive, retailers will benefit/receive payment from AEMO for this generation, while the opposite will occur at times of negative prices. While outcomes would differ across different retailers' customer base, across 2022 and 2023 the value of solar exports would have produced materially different outcomes for retailers. The high spot market prices of 2022 would have resulted in solar exports providing significant revenue. However, across 2023 with lower spot prices (and more negative prices), our analysis shows it could have resulted in a very small cost. While the cost or benefit of solar exports to a retailer will depend on a range of factors, we do not consider the specific occurrences of exports combined with negative price intervals as a reason to include exports in the interval meter load profile data.

We also recognise that retailers have a range of strategies available to manage the exposure arising from solar exports beyond adjustments to feed-in tariffs, such as sophisticated contracting products and load-shifting measures that cannot be accounted for in the wholesale cost methodology. The methodology also does not account for instances where a customer's demand is satisfied by the exports of another small customer behind a transmission node identifier.

Ultimately, we consider that the DMO is a price charged for customers' imports (or consumption), and the wholesale cost methodology is based on hedging against consumption as opposed to both consumption and generation, or the spot market outcomes a retailer is settled against. Our methodology does not seek to reflect settlement, which

---

65 Frontier Economics, *Treatment of solar exports in load profiles*, 21 May 2024.

66 Regulations, s. 8A.

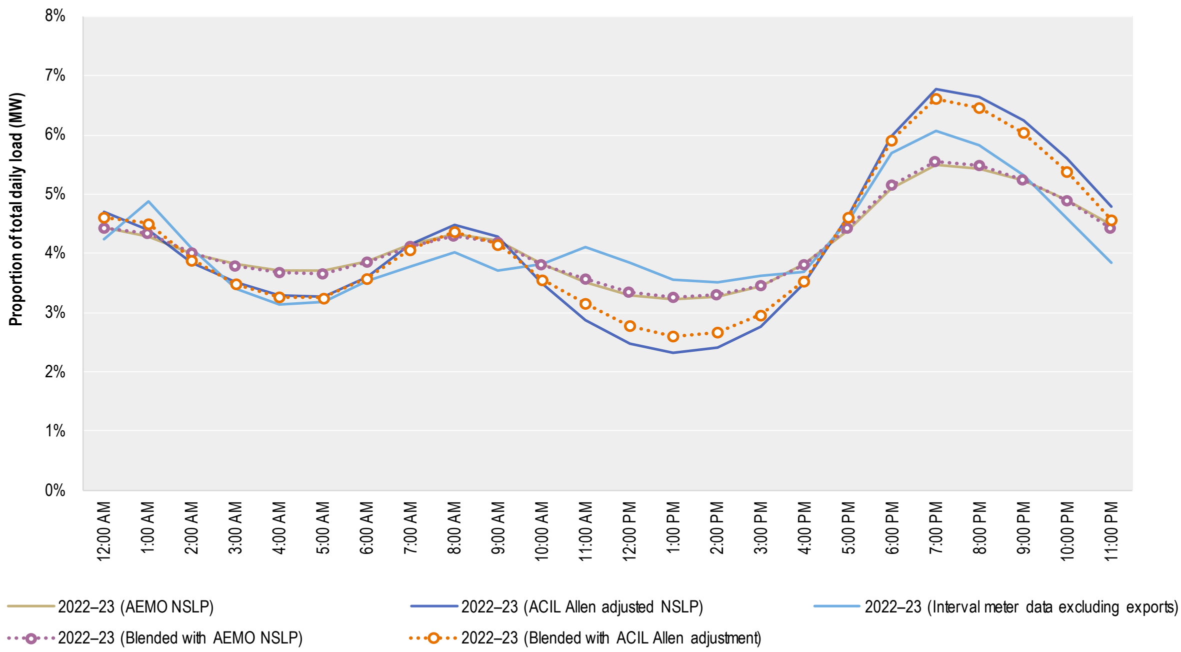
occurs against a retailer's entire load and includes customer types such as larger customers that are not covered by the DMO. Rather, it seeks to establish a tariff that retailers charge for the consumption of residential and small business customers. In addition, the current spot market modelling includes simulations with negative spot prices and the selection of the 75th percentile modelling outcome provides for the possibility that retailers may face higher than average costs.

We also note that we received limited evidence from retailers on how the treatment of solar exports could be adjusted to warrant a change in the methodology from the draft determination, considering the likely over-recovery from consumers if exports were included. Overall, we consider the current approach adequately reflects the wholesale costs and risks a retailer is expected to face in serving residential and small business electricity consumption during the DMO 6 period without resulting in an over-recovery from consumers.

However, as there may be different costs to serve solar versus non-solar customers, we are open to considering the treatment of solar exports further. We recognise that the treatment of solar exports is likely to be impacted in the future due to the increasing uptake of solar PV and other consumer energy resources, acceleration of interval meter deployment and expect that the NSLP (accumulation meter data) will become less relevant in determining the load profiles. Therefore, we will continue to observe this issue and engage with retailers to explore risk management strategies and costs associated with solar exports, to determine whether adjustments to the wholesale methodology may be required over time.

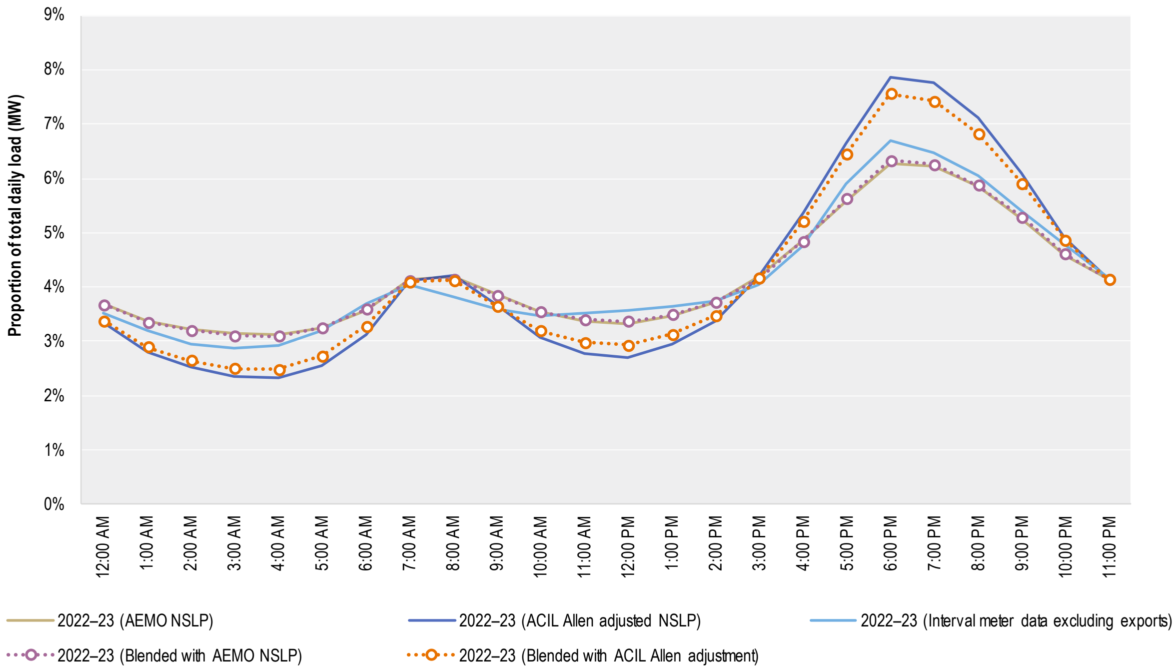
Figure 5.1 to Figure 5.5 show the average time of day load profiles used in the DMO 6 final determination. These illustrate the NSLP options we considered and the impact of blending interval meter data (excluding solar exports) with each of these. The incorporation of interval meter data has a different impact on the overall load profile across regions depending on the number of customers with interval meters in each network. For example, blending interval meter data in the Energex region has a much smaller impact on the load shape because interval meters contribute less energy in SE Queensland compared with other regions such as Ausgrid in NSW.

Figure 5.1 SA Power Networks load profile inputs



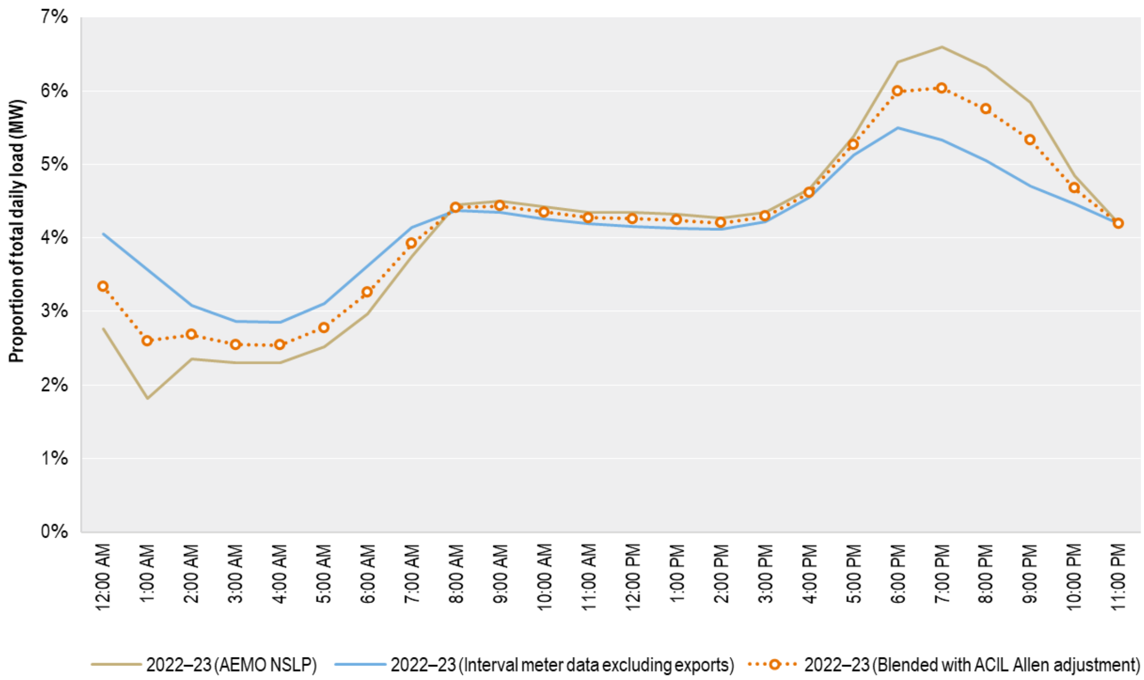
Source: AER analysis using AEMO, ACIL Allen data.

Figure 5.2 Energex load profile inputs



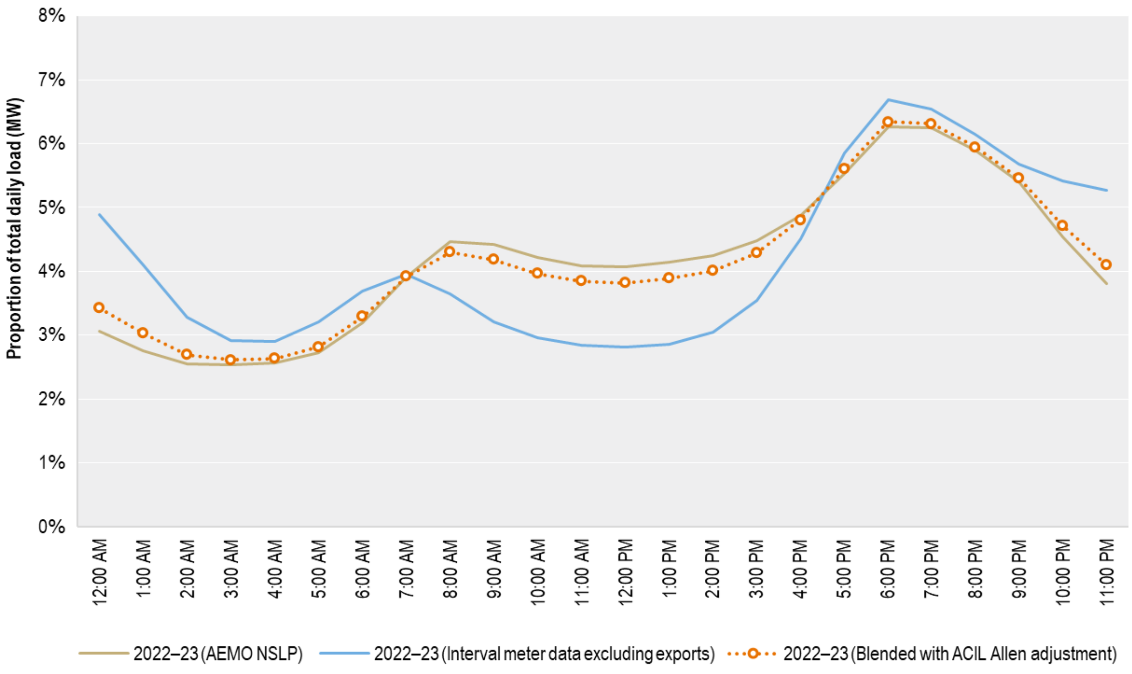
Source: AER analysis using AEMO, ACIL Allen data.

Figure 5.3 Ausgrid load profile inputs



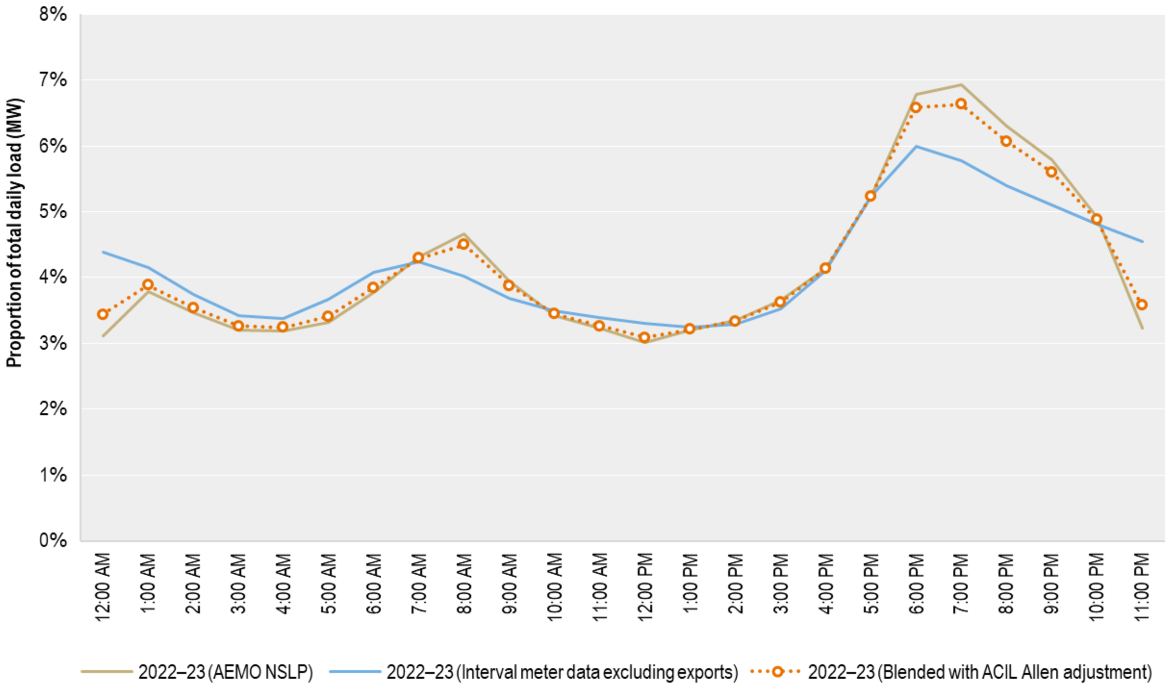
Source: AER analysis using AEMO, ACIL Allen data.

Figure 5.4 Endeavour Energy load profile inputs



Source: AER analysis using AEMO, ACIL Allen data.

Figure 5.5 Essential Energy load profile inputs



Source: AER analysis using AEMO, ACIL Allen data.

Other load profile assumptions

We have decided to maintain a single load profile for residential and small business customers and separate load profiles for each distribution network in NSW. This aligns with the draft determination and stakeholder feedback supporting consistency in approach.

5.3.2 South Australian wholesale methodology

Use of confidential contract information

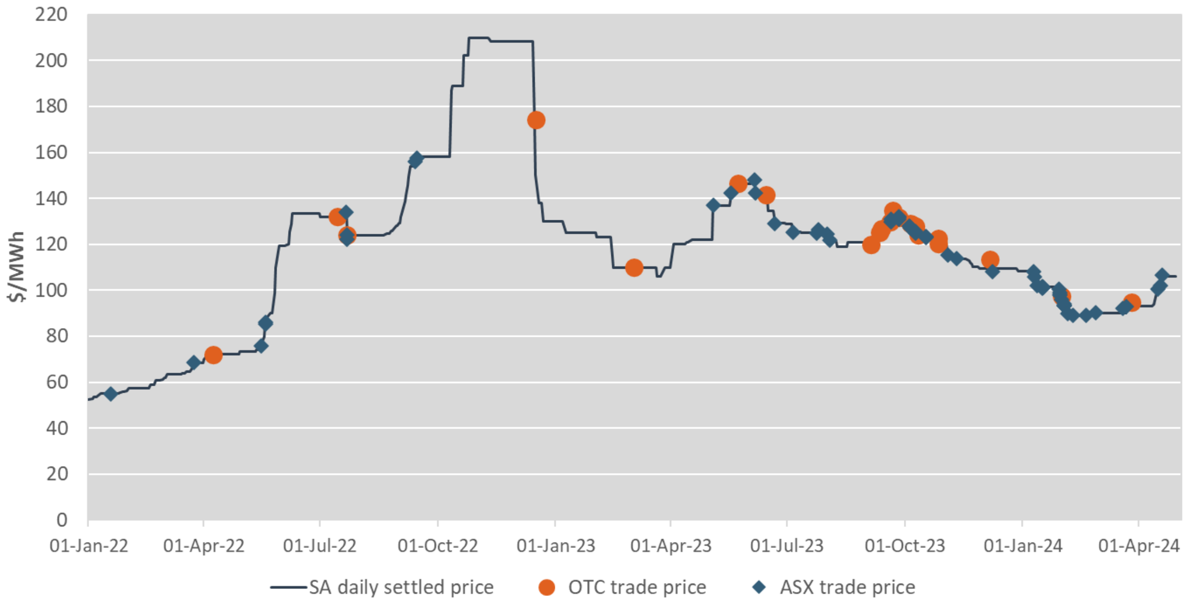
We have maintained the use of ASX data, using base futures (including the volume arising from the exercise of options), caps and the premium for call options. This aligns with our approach for DMO 5 and the DMO 6 draft determination.

For the final determination we continued to collect additional OTC contract market data from market participants in South Australia. We requested contract information for trades that had occurred over the previous 3 years in South Australia that was relevant to the DMO 6 period, to assess whether ASX data in isolation was an accurate reflection of contract prices and volumes. From the OTC data collected, we analysed how contract products, with like terms to ASX traded products, aligned with ASX prices and volumes.

The OTC data provided to the AER suggested that relevant OTC trades are broadly consistent with ASX traded contract prices and volumes (Figure 5.6). Base futures (swaps) and caps continue to be the most widely used contracts in South Australia.

Based on the data received, we have maintained our approach to only use publicly available ASX data in the wholesale cost methodology for South Australia.

Figure 5.6 OTC and ASX trade price comparison, South Australia Q3 2024



Source: AER analysis using ASX and OTC data.

Other methodologies considered

The final determination does not incorporate the use of bespoke products including Victorian contracts and SRA units in modelling wholesale costs for South Australia.

The WEC estimate for South Australia produced from the LRMC analysis was slightly lower than those resulting from the current methodology and formed a useful comparative data point at the timing of the draft determination.[67] Based on the comparable WEC estimate

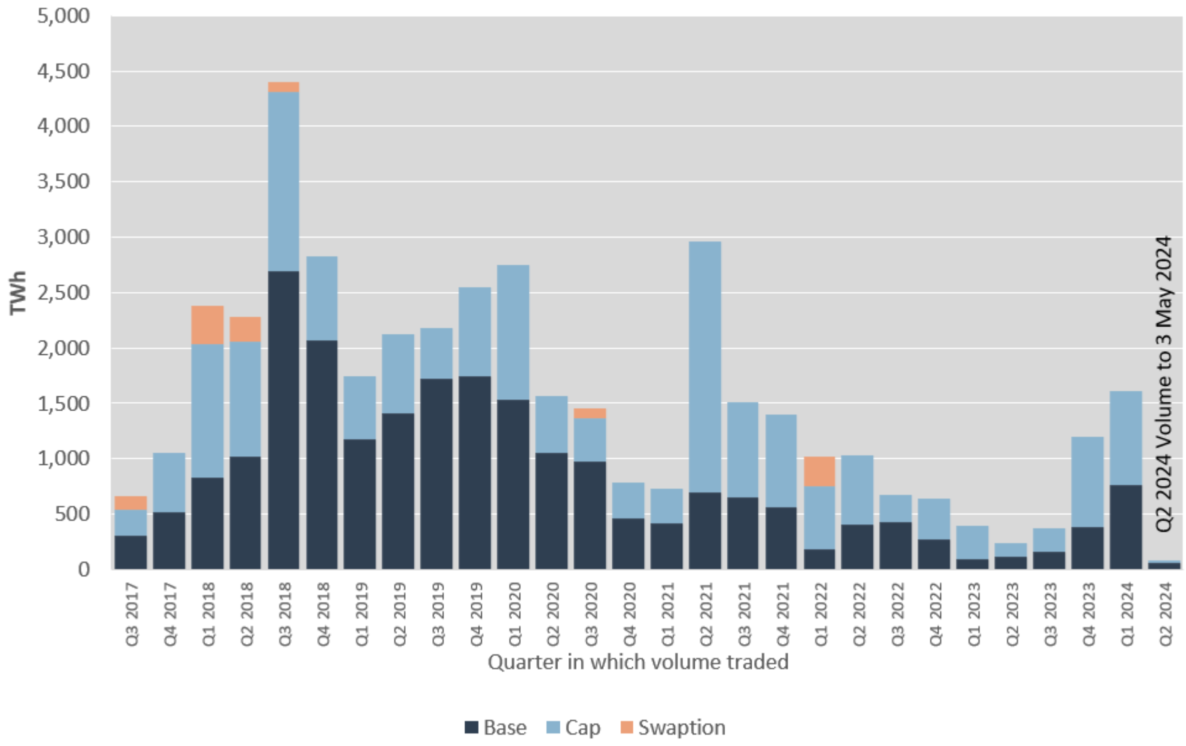
---

[67] ACIL Allen, *Draft determination - Default market offer prices 2024–25 - Long run marginal cost estimates for South Australia*, 18 March 2024.

produced from the LRMC analysis and OTC data analysis, we have decided to retain our current wholesale cost methodology for DMO 6 final determination.

Since the timing of the DMO 6 draft determination, we have continued to monitor contract market liquidity levels in South Australia and have observed additional trades in Q1 and Q2 2024 relevant to the DMO 6 period (Figure 5.7). The additional trades support our approach to use ASX data. However, given our ongoing concerns about low liquidity levels, we will continue to investigate comparative data sources to assess our wholesale cost methodology for South Australia in future determinations.

Figure 5.7 Traded volumes – ASX electricity contracts, South Australia



Note: Limited trades have been captured in our analysis for Q2 2024 because of the ASX data cut-off date of 3 May 2024 for DMO 6.
Source: AER analysis using ASX data.

5.3.3 Other wholesale cost issues

75th vs 95th percentile

The DMO 6 final determination uses the 75th percentile estimate of modelled wholesale energy 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.

While we acknowledge retailers' arguments regarding the volatility in the wholesale electricity market being a contributing factor to retailers exiting the market, we note the majority of exits occurred in the 2022–23 financial year due to a variety of factors, including the extreme market events at the time. The market has since moderated and only one retailer has voluntarily applied to exit the market in the 2023–24 financial year through surrender of its retail authorisation.[68] We remain concerned that moving to the 95th percentile to capture

[68] In March 2024, the AER approved ReAmped's application to surrender its retailer authorisation.

more extreme market events would risk unnecessarily overstating the WEC, and are satisfied that the 75th percentile estimate remains appropriate for retailers to recover their efficient costs.

Conversely, lowering to the 50th percentile estimate would increase the risk that the WEC is understated. We consider the 75th percentile reduces this risk for retailers and this percentile estimate, combined with the other decisions in the final determination, allows retailers to recover their efficient costs of providing their services without an over-recovery of costs from consumers.

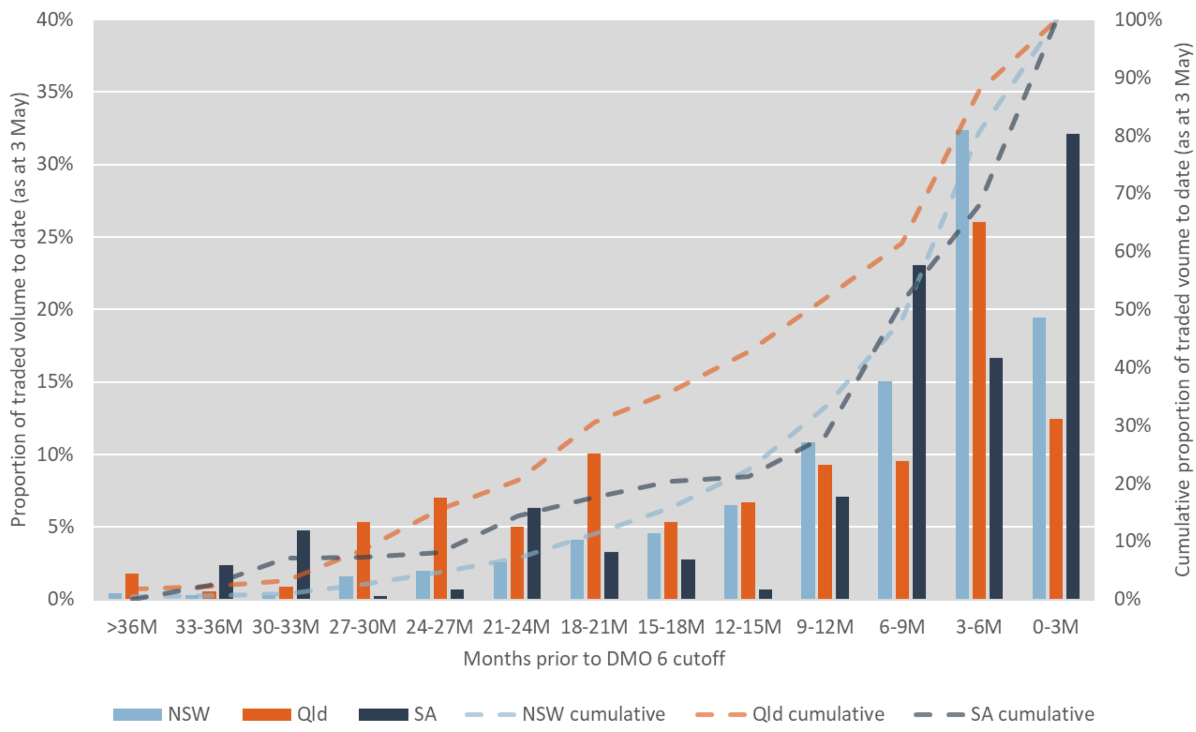
Length of book build period

The DMO 6 final determination maintains the approach to the book build from prior DMO determinations, which uses all available trades on the ASX.

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 but reflects what is occurring in the market in aggregate.

Analysis highlights that although there is limited contract trading for DMO 6 futures 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 one to 2-year period 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



Note: Proportion of total volume traded (as at 3 May 2024). Uses ASX data only.
Source: AER analysis using ASX data.

ASX options

No feedback was received on ASX options and we consider it appropriate to retain our treatment of options from previous DMO determinations. This includes the 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 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

We note Origin Energy's concerns on the potential for fuel prices for combined cycle gas plants to exceed the assumed cap of $12 per GJ as set in the draft determination. We have further examined market indications of wholesale gas prices and recognise the potential for prices to exceed the cap. As a result, ACIL Allen has adjusted the fuel price assumptions within the wholesale cost modelling to include seasonal gas prices of $11–12 per GJ in non-winter months and $13–15 per GJ in winter months. These updated price forecasts were produced by ACIL Allen and better align with price indications reported in our Wholesale markets quarterly report – Q1 2024.[69]

Other wholesale cost modelling assumptions

We have made adjustments to other assumptions within the wholesale cost modelling done by our consultant ACIL Allen based on stakeholder feedback.

- **AEMO fees:** We agree that the wholesale cost methodology should reflect the latest adjustments to AEMO fees. To capture the fixed component of AEMO's fees, we have adjusted the methodology to include this additional cost as a fixed annual dollar per customer amount. We will continue to capture the variable costs as directly expressed by AEMO, which we have multiplied by the individual small customer distribution usage amounts used within the DMO to produce an annual cost. Overall this has resulted in the variable component decreasing by around $0.45/MWh, but this is more than offset by the fixed component ($0.23 per customer per week).
- **AEMO prudential requirements:** The winter months in ACIL Allen's modelling have been adjusted to April to August in line with AEMO's prudential requirements in response to Energy Locals' submission. This results in an approximate $0.03/MWh increase. We also note Energy Locals' view on forecast daily usage figures for April but have not made any adjustments because we consider forecast daily usage figures are unique to each participant and a change would not be representative of most retailers.
- **Unaccounted for energy:** We have not adjusted the methodology to account for unaccounted for energy for this determination. Limited data is available publicly to determine the materiality of these costs and we expect unaccounted for energy to be a very small percentage of total distribution losses.
- **Wholesale spot price modelling and hedging strategy:** Other than the adjustment to gas prices noted above, we have not requested ACIL Allen make changes to its spot price modelling or hedging strategy used to model wholesale costs. We consider that the current modelling still produces variability in spot prices reflective of that observed in the current wholesale market. Because ACIL Allen reviews key inputs and assumptions into the modelling each year (such as generator availability, fuel costs, and supply and demand drivers), we consider that the current modelling simulations produce a reasonable estimate of the relevant financial year spot market outcomes, noting that additional variations in inputs will not always result in a more accurate forecast. For the

69 AER, Q1 2024 Wholesale markets quarterly report, 18 April 2024, p. 18.

hedging strategy, the outcome of a small shift to an increase in cap contracts (from base futures) reflects changing wholesale market outcomes and contracting products used by retailers to hedge and reduce exposure to spot market prices. We consider this reflects a prudent retailer, who would seek to minimise its exposure to wholesale market variability.

Other responses received from stakeholders

We acknowledge stakeholder concerns that wholesale costs in the DMO remain elevated compared with earlier determinations despite moderations in spot market prices. However, we emphasise that the book build approach to incorporate all relevant ASX contracts includes contracts purchased at inflated prices during 2022 for the DMO 6 period. The presence of these higher contract prices means that wholesale costs for the DMO have not fallen as sharply as spot market prices and in these conditions there is a lag between reductions in spot market prices and the prices paid by consumers. We also note that while contract prices for DMO 6 have fallen substantially from the high prices observed in 2022, these prices remain above the low levels observed across 2020 and 2021 (around $50–80 per MWh). The extent to which those low prices from 2020 and 2021 have been captured in the DMO 6 book build period and resulting trade-weighted prices is limited compared to DMO 5, which contributes to the wholesale cost outcomes for DMO 6.

Other drivers impacting wholesale costs for DMO 6 are explored in section 5.3.4 below.

We agree with the Queensland Energy Minister’s position on the benefits of enhancing transparency in the wholesale cost methodology but note inputs such as the interval meter dataset provided by AEMO are confidential and cannot be published. We will continue to balance data transparency and the information afforded by confidential data sources in future determinations, using public information where practical and available.

5.3.4 Wholesale energy costs

Wholesale energy costs are forecast to decrease across almost all DMO regions and consumer types for the DMO 6 period.

This has been driven by movements in contract prices, the time-of-day shape of load profiles used and spot price outcomes. The movements in the futures 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 $11.65/MWh and a decrease in cap contract prices of $1.28/MWh
- for Queensland – a decrease in base futures contract prices of $2.71/MWh and an increase in cap contract prices of $0.11/MWh
- for South Australia – a decrease in base futures contract prices of $2.27/MWh and a decrease in cap contract prices of $0.74/MWh.

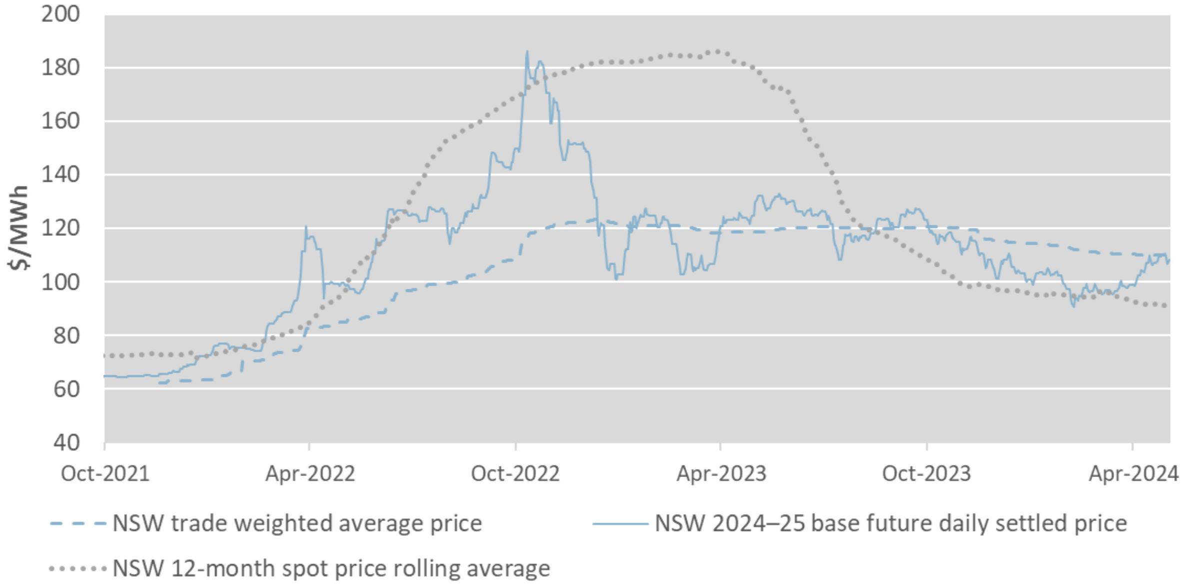
Financial year 2024–25 base future prices peaked in October 2022 before falling sharply in the months that immediately followed. Prices remained relatively stable throughout 2023 and fell in the final 3 months due to mild weather and low prices in the spot market. Base future prices have risen slightly during 2024 in all regions, potentially driven by higher spot market outcomes in Q1 2024 (Figures Figure 5.9, Figure 5.10 and Figure 5.11).[70] We also note that

---

70 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 Figures 5.9, 5.10 and 5.11 only appears after at least 1 MW has been traded for each quarter of the 2024–25 financial year.

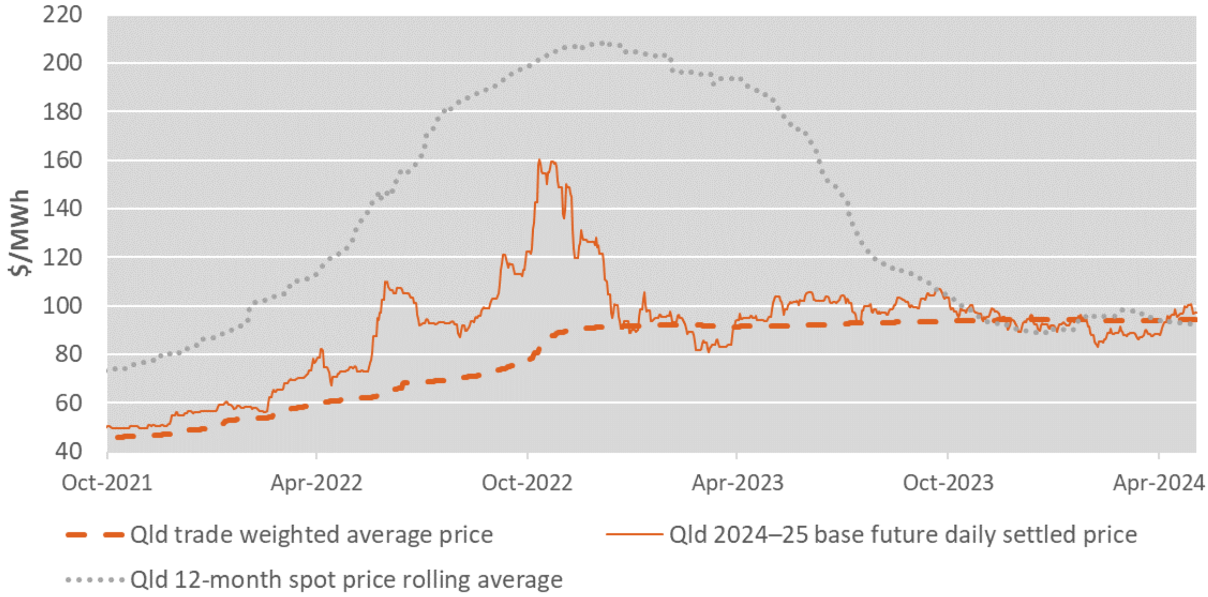
trade weighted average base future prices throughout late 2023 and early 2024 have remained fairly aligned with the 12-month rolling average of spot prices. As noted earlier, contract prices (and spot prices) have decreased from the peak observed in 2022 but remain elevated compared to 2020 and 2021. The DMO 6 book build period only partially captures the lower priced contracting products from 2021 compared to previous determinations, and therefore the relatively higher priced products including and following the peak observed in 2022 are more of a factor in wholesale costs for this determination.

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



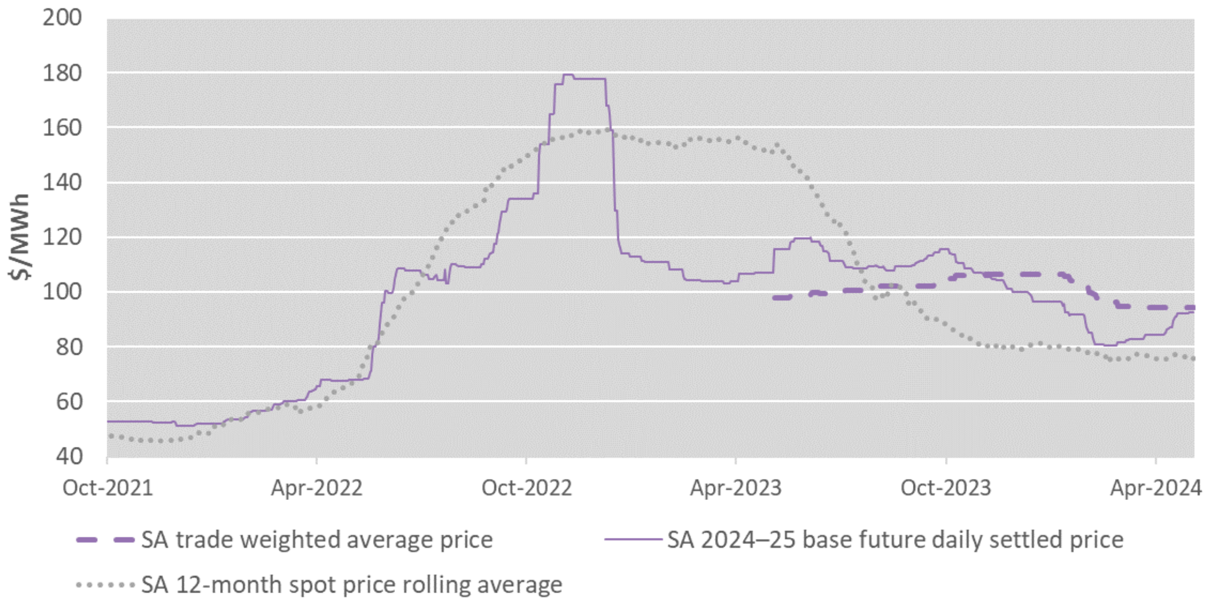
Source: AER analysis using ASX data.

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



Source: AER analysis using ASX data.

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



Source: AER analysis using ASX data.

The final wholesale costs for DMO 6 are set in Table 5.2, together with the costs used for DMO 5 (2023–24) for comparison.

We note that in Queensland, an increase in cap contract prices during summer months when demand is greatest (Q1) contributed to wholesale costs only decreasing slightly overall compared to other DMO regions. For South Australia, the lower wholesale costs were driven by a large decrease in cap contract prices during the peak demand period of summer (Q1), which more than offset increases observed during other quarters.

There has been a decrease in a number of other wholesale costs that have contributed to the wholesale cost outcomes. Because no compensation claims have been finalised since the DMO 5 final determination, no costs associated with the June 2022 wholesale market events have been included in DMO 6. There have also been decreases across ancillary service and prudential costs. In South Australia, costs associated with directions from AEMO for system security purposes have increased.

Because we have adjusted our methodology to reflect changes in AEMO's fee recovery structure, the variable cost (which is how fees were captured in previous DMO determinations) has fallen. However, this is more than offset by increases resulting from the fixed cost recovery.

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

Distribution region	Customer type	2023–24	2024–25	Change year-on-year
Ausgrid	Flat rate	$186.09	$162.99	-12.4%
	CL 1	$111.95	$106.85	-4.6%
	CL 2	$111.70	$106.70	-4.5%

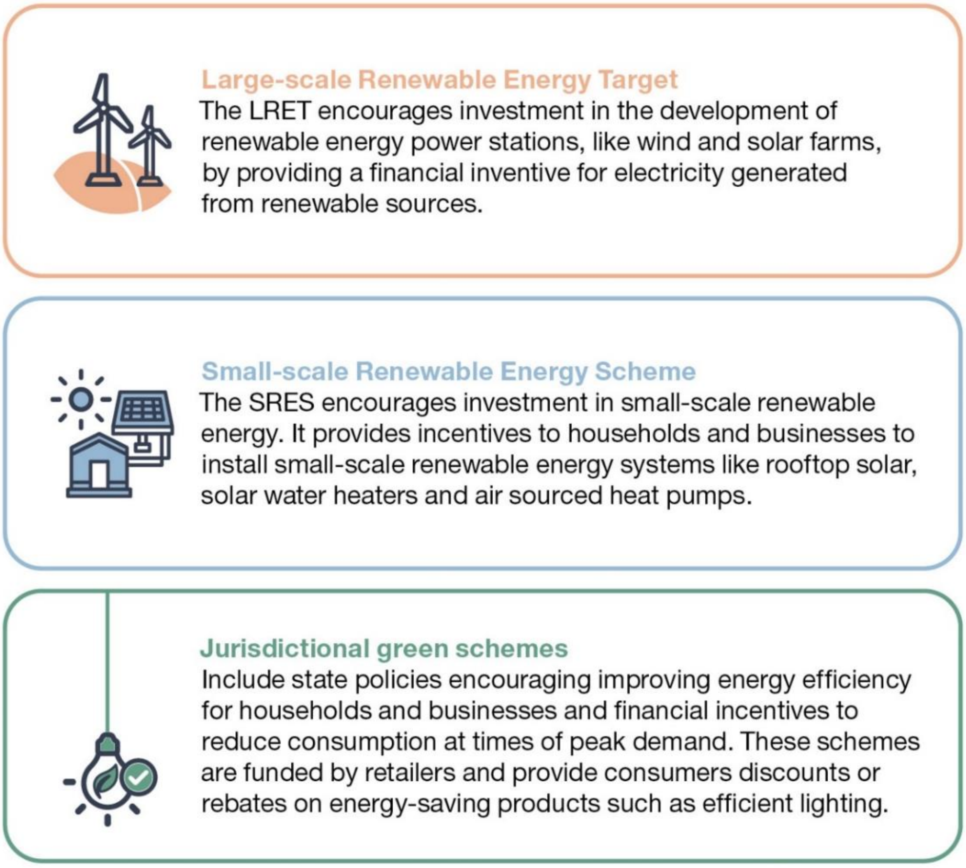
Distribution region	Customer type	2023–24	2024–25	Change year-on-year
Endeavour Energy	Flat rate	$189.50	$173.70	-8.3%
	CL 1	$177.78	$108.20	-39.1%
	CL 2	$177.78	$108.20	-39.1%
Essential Energy	Flat rate	$178.00	$163.18	-8.3%
	CL 1	$110.08	$104.52	-5.1%
	CL 2	$110.08	$104.52	-5.1%
Energex	Flat rate	$167.03	$164.97	-1.2%
	CL 1	$112.52	$104.17	-7.4%
	CL 2	$119.80	$112.60	-6.0%
SA Power Networks	Flat rate	$226.13	$180.15	-20.3%
	CL 1	$110.75	$114.46	3.3%

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

6 Environmental costs

As stated in previous DMO determinations, environmental schemes at both national and state levels require retailers to procure electricity supply from renewable sources and improve customer energy efficiency. The costs of these schemes are incurred by retailers and are included as a cost component of the retail price for electricity.

Environmental costs broadly fall into 3 main categories:



Most environmental costs relate to complying with the Renewable Energy Target (RET). Retailers have an obligation to purchase renewable energy certificates and surrender them to the Clean Energy Regulator (CER) in proportion to the overall amount of energy consumed by their customers.

The RET is made up of the Large-scale Renewable Energy Target and the Small-scale Renewable Energy Scheme (SRES). Large-scale Renewable Energy Target costs are incurred by retailers to acquire the necessary amount of Large-scale Generation Certificates (LGCs). Similarly, Small-scale Renewable Energy Scheme costs are incurred by retailers to acquire the necessary amount of Small-scale Technology Certificates (STCs).

6.1 Draft determination

In the DMO 6 draft determination we proposed to continue using our market-based approach to forecast environmental costs with updates for any new and amended schemes. We considered it reasonable to retain our methodology, noting that the submissions to the DMO 6 draft determination generally supported retaining the environmental cost forecasting methodology.

6.2 Stakeholder views

Of the 5 stakeholder submissions that provided input into the 'Environmental Costs' component of the DMO 6 draft determinations (Alinta Energy, 1st Energy, Energy Locals, Origin Energy and PIAC/SACOSS/ACOSS) no submission raised any issues with our proposal to retain our market-based approach to environmental cost forecasting, the submissions focused on adjustments to the methodology.

1st Energy asked that the AER assesses whether a true-up mechanism as occurs with the VDO is appropriate, as they considered year-on-year environmental costs have been understated.[71]

Energy Locals specifically questioned the accuracy of ACIL Allen's assumption of a retailer purchasing spot LGCs 4.7 years in advance of the liability surrender date. They argued this approach was not indicative of a reasonable and prudent retailer.[72] Energy Locals considered the current approach reflects an inefficient use of capital for growing retailers that have less certainty of operations and that this would be more akin to speculating than hedging.

They proposed that the observation period used in the calculations should align with the estimation of the wholesale energy costs and considered a bookbuild period of 18 months to 2 years to be more acceptable.[73]

Energy Locals also raised issues with ACIL Allen's calculations for Small-scale Technology Certificates (STCs) and Small-scale Technology Percentage (STPs) as part of SRES costs. They noted that for DMO 5, ACIL Allen considered both its own forecast and that of the CER's non-binding STP but chose to rely only on the CER's non-binding STP (which Energy Locals considered an underestimation of 3.27%).[74]

Energy Locals opposed ACIL Allen's continued use of a non-binding CER estimate for DMO 6 and asked for ACIL Allen to share its reasoning on why it considered the non-binding estimate correct, and that the market can deliver the forecast quantum of certificates.[75]

Submissions from PIAC/SACOSS/ACOSS and Energy Locals recommended future reforms to state and federal laws that impose compliance costs on retailers and are reflected in the 'environmental costs' component of the DMO. [76] However, PIAC/SACOSS/ACOSS acknowledged that these recommended reforms are beyond the current remit of the AER's functions and powers relating to DMO price determinations.

---

71 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

72 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 7.

73 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 8.

74 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 8.

75 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 8.

76 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 11–12; PIAC/SACOSS/ACOSS, joint *Submission to DMO 6 draft determination*, 11 April 2024, p. 8.

6.3 Final determination

Having considered stakeholder submissions and the available information on environmental costs, we propose to retain our market-based approach to environmental cost forecasting with updates for new and amended schemes.

The regulations require us to have regard to the costs retailers incur in complying with federal and state/territory laws when determining the DMO price, which include the RET and the various jurisdictional efficiency schemes. Therefore, we consider it appropriate for the DMO price to include these costs.

Regarding 1st Energy's submission recommending consideration of a true-up mechanism, we note that the regulations direct the AER to determine DMO prices with regard to the forecast costs for the upcoming DMO period. As previously noted in prior determinations, we do not consider true-up mechanisms appropriate.[77] They would reduce transparency in our price setting process and would unnecessarily alter our best forecast of costs for the upcoming DMO period due to differences between prior forecasts and actual costs in the prior DMO period.

In response to Energy Locals' specific concerns with spot LGCs, we confirm that ACIL Allen only employs base future contracts (which have no cash outlay until settlement) in its calculations. Despite this, we acknowledge Energy Locals' position on spot LGCs and recognise that the price for LGCs has increased significantly in recent years.[78] However, we remain of the view that a market-based approach that develops a trade-weighted average price based on all trades for the relevant period is appropriate. This aligns with the wholesale methodology, which also uses a trade-weighted average of wholesale futures across the full period of trades, rather than a subset of trades within a set observation window.

We also acknowledge Energy Locals' concerns with using the CER's non-binding STP estimates for the second half of the determination period in determining SRES costs.

We have reviewed CER's non-binding STP estimates from the prior year and compared these to the binding STP across DMO periods.[79] The STP depends on the number of STCs created, which is driven by uptake in small scale renewable technology such as solar PV and water heaters. In recent years there has been an accelerated uptake in solar PV installations that has been difficult to accurately forecast. These estimates are set out in Figure 6.1 and demonstrate that, with the exception of 2023, CER's non-binding STP has been an underestimate.

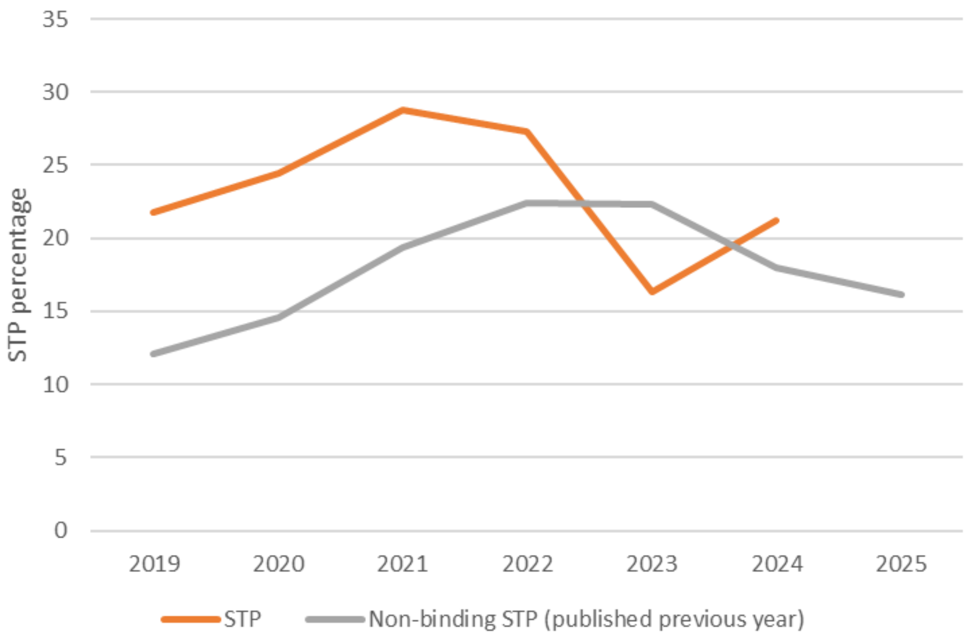
---

77 AER, *Default market offer 2022–23 final determination,* P 16.

78 ACIL Allen, *Default market offer 2024–25 final determination technical report*, Fig 4.27.

79 CER, Small-scale technology percentage, accessed 9 May 2025.

Figure 6.1 STP versus non-binding estimate (prior year)



Source: CER, Small-scale technology percentage.

While CER is required to issue STP forecasts 1 and 2 years out, these are non-binding estimates intended to give an indication of what the STP could be in those years. CER advise that its non-binding estimates should be considered a general guide only.[80]

We note CER recently engaged consultants (ACIL Allen and Marsden Jacobs) to analyse and model aspects of the SRES. This work included reviewing the market for STC and estimating the STP numbers for 2025 and is now published by CER.[81]

In its report, ACIL Allen found a higher equivalent STP (~18%) than Marsden Jacobs (~14%). CER adopted the midpoint (~16%) as its non-binding STP estimate for 2025. ACIL Allen in its separate advice to the AER has reiterated its view that 18% is the best estimate of the 2025 STP.

In determining environmental cost inputs for 2024–25 we have had regard to the range of estimates for STP for 2025, as well as prior estimates compared to the actual STP. Given the tendency for the non-binding STP to be an underestimate, we consider it appropriate to use ACIL Allen's estimate of ~18%, which is the upper bound of the range and exceeds CER's non-binding estimate by ~2 percentage points. We note that ACIL Allen has confirmed this results in an increase of $0.40/MWh compared with basing STC costs on the non-binding CER estimate of ~16%.

Environmental cost inputs

The environmental cost inputs for 2024–25 are in Table 6.1, together with inputs used for 2023–24 for comparison, and are included in the charts shown in Appendix D.

80 CER, Small-scale technology percentage, accessed 9 May 2025.

81 CER, Small-scale technology percentage modelling reports, Nov 2023.

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

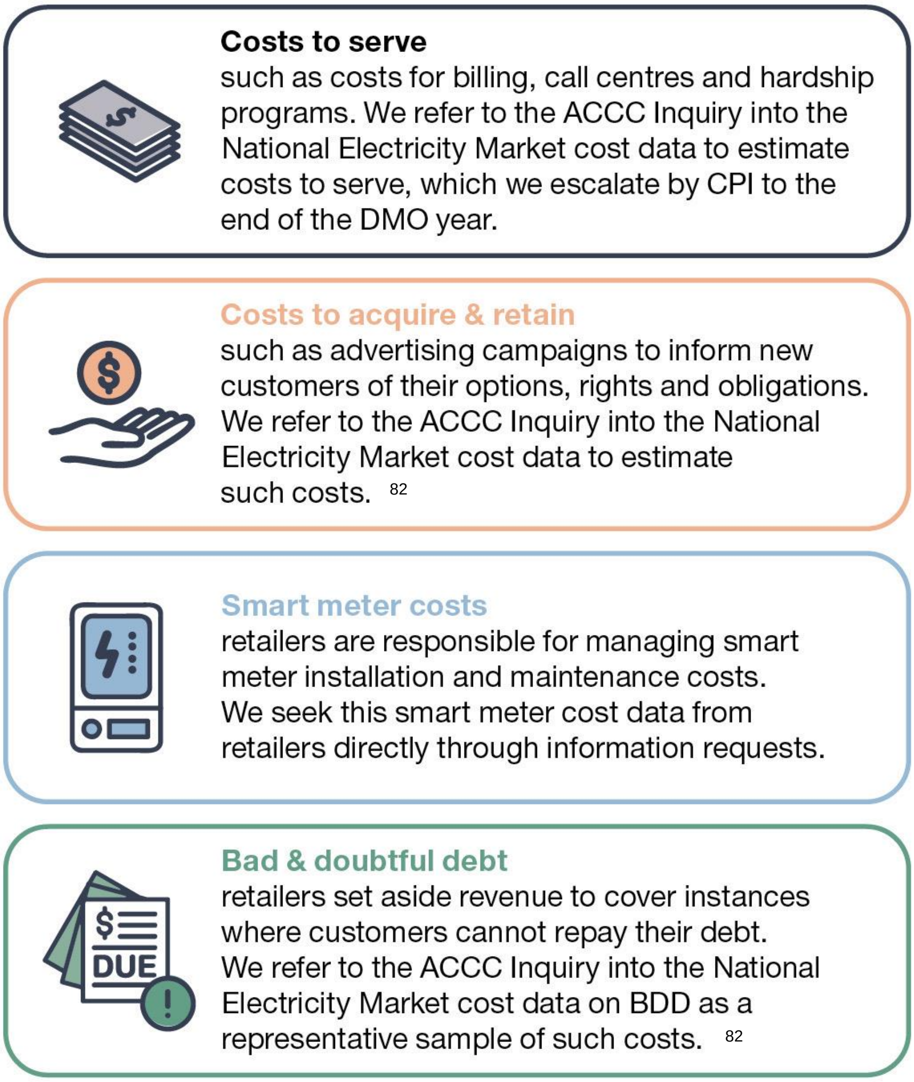
Distribution region	Tariff	2023–24 (per MWh)	2024–25 (per MWh)	Change year-on-year
Ausgrid	Flat rate	$18.68	$19.64	5.1%
	CL 1	$18.71	$19.75	5.6%
	CL 2	$18.71	$19.75	5.6%
Endeavour Energy	Flat rate	$18.80	$19.81	5.4%
	CL 1	$18.80	$19.81	5.4%
	CL 2	$18.80	$19.81	5.4%
Essential Energy	Flat rate	$18.48	$19.34	4.7%
	CL 1	$18.48	$19.34	4.7%
	CL 2	$18.48	$19.34	4.7%
Energex	Flat rate	$15.26	$16.53	8.3%
	CL 1	$15.26	$16.53	8.3%
	CL 2	$15.26	$16.53	8.3%
SA Power Networks	Flat rate	$19.33	$22.16	14.6%
	CL 1	$19.33	$22.16	14.6%

Note: CL refers to controlled load.
Source: ACIL Allen, *Default market offer 2024–25 final determination technical report*.

7 Retail costs

Retail costs are the costs a retailer incurs in providing retail and customer services. These range from operating expenses (providing retail services like billing systems, managing customer service, and including expenditure on debt collection) through to the costs required to comply with regulatory obligations.

The retailer costs include:



The ‘cost-stack’ methodology used for setting retail costs was established for DMO 4. It provides transparency by outlining the various retail costs individually and ensuring consistency with pricing between regions.

As outlined in the draft determination, we consider the current ‘cost-stack’ methodology remains appropriate. The calculations for the final determination will use this methodology, albeit with updated data from:

---

82 ACCC, Inquiry into the National Electricity Market report – December 2023.

- the ACCC, which is made up of reported data from Tier 1 retailers and several 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.

For costs to serve and costs to acquire and retain customers, we refer to ACCC cost data.[83] As of December 2023, the ACCC cost data now reports retail and other cost data on a dollar per small business customer basis. For smart meter costs, we source this data from retailers directly through information requests. In our estimation process, we escalate all retail costs by the CPI to the end of the DMO year.[84]

Retailers make up-front investments, which depreciate over time. The AER does not separately determine depreciation and amortisation of costs, but instead sets a retail component that includes an efficient margin informed by earnings before interest, taxes, depreciation and amortisation (EBITDA).

7.1 Draft determination

7.1.1 Bad and doubtful debt

Bad and doubtful debts are the retailer costs incurred and written off as unpaid bills. Retailers set aside revenue to cover costs such as:

- 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).

The ACCC considers bad debt costs (which includes doubtful debts) separately from 'retail and other' costs within its cost-stack data. While the ACCC had historically collected this information, it only commenced publishing bad debt costs since their recent December 2023 Inquiry into the National Electricity Market report.

We intend to use allowance figures for residential and small business based on the weighted average of the actual data published by the ACCC.

With the increased granularity of the ACCC's disaggregated data available, in the draft determination we proposed to consider bad and doubtful debt costs on a state-based approach, rather than one national figure. We considered that using the disaggregated state-based data provided greater insight into the difference in cost faced by retailers across the various DMO regions.

7.1.2 Smart meter costs

As discussed in both the DMO 6 issues paper and draft determination, we anticipate a change in the rate of retailer installations due to the AEMC's installation acceleration target period commencing in July 2025 (pending completion of the rule change process).

---

83 ACCC, Inquiry into the National Electricity Market Report - December 2023.

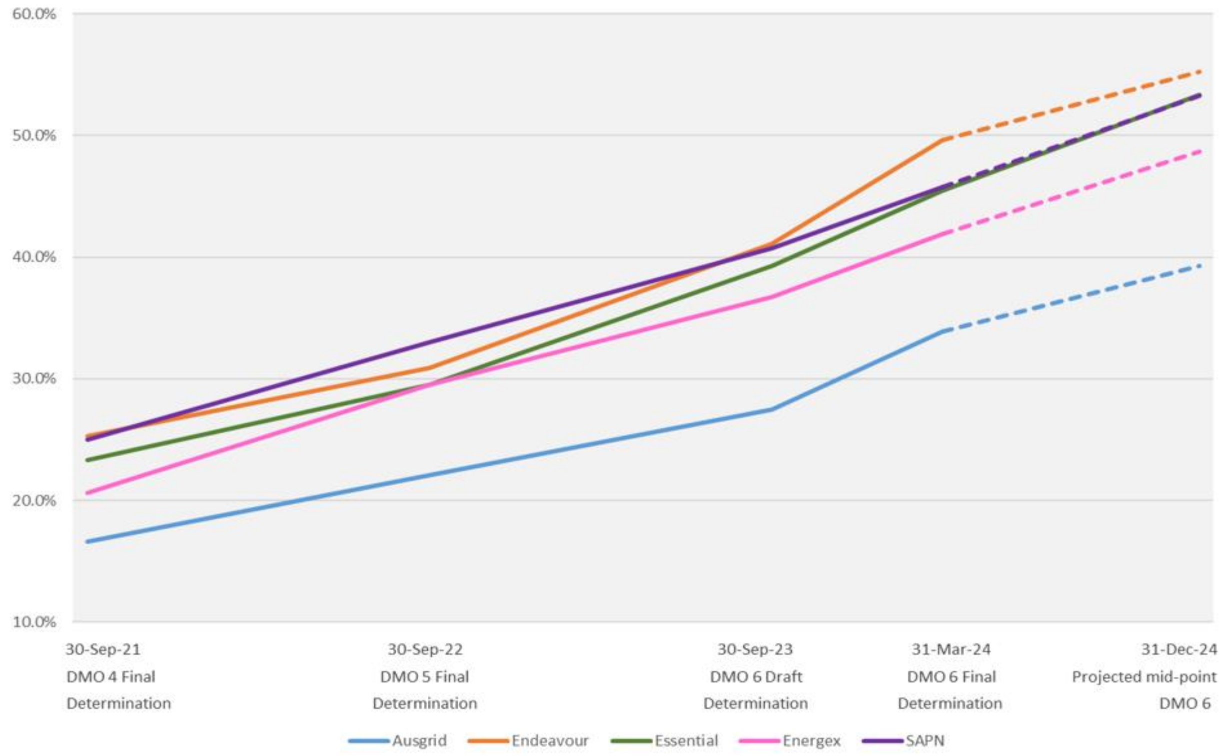
84 RBA, 2024–25 inflation forecast of 7.12% in the RBA May 2024 forecast for the 2 years ending June 2025.

With this anticipated increase in mind, we have sought greater stakeholder insight on 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. Our retailer data requests issued on 30 September 2023 and 31 March 2024 sought:

- the number of customers by meter and tariff type
- the projected customer numbers as of 31 December 2024
- 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.

In Figure 7.1Figure 7.2 we have outlined a historic trend analysis of the rate of installations (September 2021 to March 2024). The rate of installations has gradually increased in all regions. Our analysis of this increased rate of installations in the DMO 6 draft determination was based on quarterly retail performance reports data (based on data to December 2023).[85] This updated analysis is based on more recent voluntary data received from 10 retailers using data up to 31 March 2024.

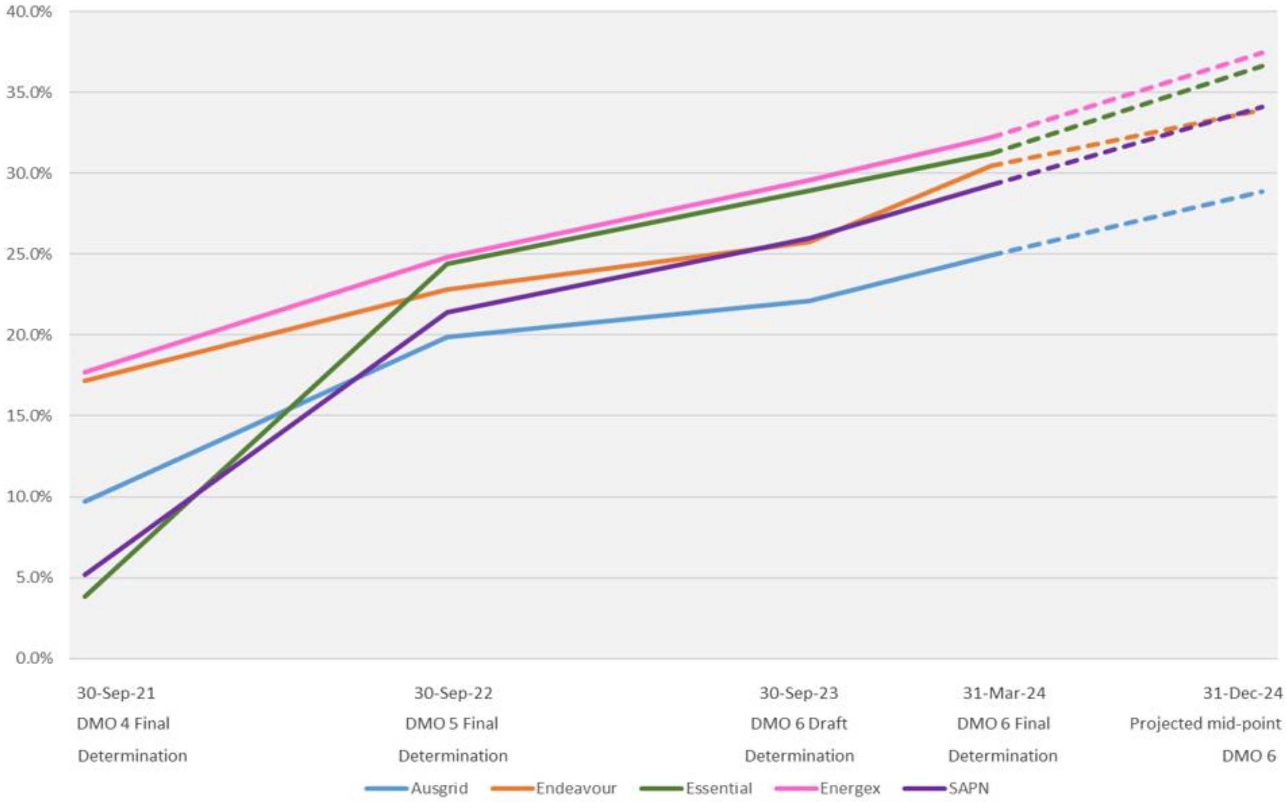
Figure 7.1 Percentage of residential customers with smart meters



Source: AER Smart meter data request data as of 31 March 2024

[85] AER, Draft determination, default market offer prices 2024–25, 19 March 2024, p. 43.

Figure 7.2 Percentage of small business customers with smart meters



Source: AER Smart meter data request data as of 31 March 2024

Historic versus projected

Across both the DMO 6 issues paper and the draft determination we have been exploring the question of whether the AER should project advanced meter installations instead of using historic installation data in future DMO decisions.

In the draft determination we proposed to continue the current historical approach until the legacy meter retirement plans are in place.

Up-front fees

Our issues paper asked whether we should factor up-front fees in our smart meter calculations. These are any up-front fees a retailer may charge as part of a market or standing offer (such as a meter connection fee or an additional meter read). We understood from prior DMO periods that some retailers opt for this one-off fee approach instead of recovering these costs through retail tariff prices, which are subject to the DMO price protection and reference price regulations.

Based on feedback received in the submissions to the DMO 6 issues paper and the responses to our information requests, we understood a limited number of retailers charged up-front fees. Because of this we were confident that the risk of over recovery (full recovery within DMO price as well as in up-front fees) would be minimal for the DMO 6 period.

Any retailer not charging up-front fees would be recovering less of its actual interval metering costs if up-front fees were not included in the cost of smart meters (such as in DMO 5).

For the draft determination, we proposed including up-front fees. We considered this reduced the incentive for more retailers to add on these fees and aligned with the AEMC recent reform recommending up-front fees be prohibited. Once prohibited, the issue of over or under-recovery from including fees in the calculation will no longer be a concern.

Costs of capital

In DMO 5, retailers recommended that the AER incorporate a working capital allowance to reflect expected increased costs faced and incentivise retailers to embrace a faster rollout of advanced meters. At the time of publishing the DMO 5 final determination we did not consider an adjustment for working capital was necessary based on the installation data available.

Whiles Figure 7.1Figure 7.2 suggest a reasonably straight trajectory for residential installations up to 31 March 2024 period, we acknowledge feedback from certain retailers throughout the DMO 6 consultation period that they have been increasing installations.

The draft determination proposed to include an estimate for a cost of capital. This additional cost would cover the shortfall between any actual installation numbers captured in our data and the projected installations still to occur during the DMO 6 year.

7.2 Stakeholder views

7.2.1 Bad and doubtful debt

Of the 3 stakeholder submissions that provided feedback on the bad and doubtful debt component of the draft determination, Alinta Energy and ENGIE supported the AER's use of state-based data published by the ACCC.[86] In its submission, Alinta Energy noted that state-based data improves the accuracy of the DMO price and reflects local market conditions for retailers operating in those areas.[87]

In contrast, the combined submission by PIAC, SACOSS and ACOSS sought more clarity on the calculation of bad and doubtful debt relating to the provisions that energy retailers make regarding this debt. They claimed that the higher the provision made against unrecoverable debt, the more an energy retailer may benefit if debt recovery levels remain generally stable.[88]

7.2.2 Smart metering costs

Historic versus projected

Alinta Energy, ENGIE, Origin Energy and Momentum Energy supported the AER's intention to continue using historical installation data until energy retailers have legacy meter retirement plans in place.[89]

In contrast, the AEC is the only stakeholder that favoured a forecasting approach over a reliance on historical data in determining smart meter costs. They suggested that this approach may disincentivise smart meter deployment due to the likelihood of estimated costs

86 Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2, ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

87 Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

88 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p. 7.

89 Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2, ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3, Momentum Energy, *Submission to DMO 6 draft determination*, 10 April 2024, p. 3, Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 9.

being inaccurate and the difference between actual capital costs not being included.[90] However, the AEC does welcome the AER's intention to employ a forecasting method once legacy meter retirement plans are in place.[91]

Up-front fees

In their combined submission, PIAC, SACOSS and ACOSS raised concerns with the AER's decision to include up-front smart meter fees and disagreed with the AER's confidence that energy retailers will not overcharge consumers. They sought further detail from the AER on how it came to this viewpoint.[92] The South Australian Department for Energy and Mining held a similar view that the inclusion of up-front smart meter fees could result in some energy retailers over-recovering costs and questioned why the AER changed its position on this.[93]

Origin Energy supported the AER's decision to maintain up-front installation fees in the DMO smart meter allowance calculation. It considered that this approach aligns with the future intent of the AEMC metering reforms and allows retailers not charging up-front fees to recover their costs.[94]

Methodology update

While not something featured in the draft determination, EnergyAustralia raised a concern relating to the validity of the AER's current approach for calculating the smart meter allowance in NSW.[95]

These changes refer to NSW DNSPs proposing to update their recovery method for legacy accumulation meter costs in 2024–25 onwards, namely[96]:

- Ausgrid – metering charge that will remove the capital and non-capital charges and instead have a single combined amount to all customers who currently pay a metering charge to Ausgrid.
- Endeavour Energy and Essential Energy – metering charge that will be moved from Alternative Control Services (ACS) to Standard Control Services (SCS) – therefore, applying to 100% of customers.

EnergyAustralia submitted that this will significantly impact how retailers are charged and proposed an alternative approach to calculating the smart meter allowance for NSW regions. This alternative was to deduct a portion of the ACS allowance based on the percentage of customers who do not pay for ACS.[97]

Cost of capital

In our consultation activities stakeholders questioned our proposal to include an estimate for a cost of capital. Despite understanding this additional allowance was set to cover the

---

90 AEC, *Submission to DMO 6 draft determination*, 13 April 2024, p. 6.

91 AEC, *Submission to DMO 6 draft determination*, 13 April 2024, p. 6.

92 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p. 7.

93 South Australian Department for Energy and Mining, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

94 Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 9.

95 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 8–10.

96 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 8.

97 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 8–9.

shortfall between actual and projected installations, some questioned the accuracy of the amount calculated by the AER, and proposed that inaccuracies in our estimate could inadvertently discourage the rollout efforts retailers make.

However, in the written submissions no stakeholders challenged our proposal and calculation. ENGIE's submission did seek further clarification in the final determination on the calculating of this cost of capital amount.[98]

7.2.3 Cost-stack methodology

In their submission Energy Locals noted that salaries and wages are a major part of a retailer's operating costs and that broad economic factors (such as inflation and CPI) have a direct impact on such costs. They acknowledged the AER's consideration of these broad economic factors for the competition allowance and argued that such factors should also be a key consideration for all elements in the cost-stack methodology.[99]

Energy Locals also raised an issue associated with extensive delays experienced for retailer reimbursement of customer concessions. They requested this cost be factored into our cost-stack methodology, because they claim it is the responsibility of retailers to fund the cashflow associated with customer concessions.[100] Energy Locals highlighted that this is an issue across multiple jurisdictions, and retailers are currently burdened with carrying the cost of this debt and fund the shortfall in cash.[101]

PIAC/SACOSS/ACOSS questioned whether the DMO objective to allow retailers to recover efficient costs to serve should be viewed as including reasonable costs to acquire and retain customers (CARC). PIAC/SACOSS/ACOSS view CARC as a 'retail expenditure' where retailers decide when and how to incur them and do so according to their own business needs. They submitted that CARC could (and arguably should) be allowed for as part of the overall retail margin rather than accounted for explicitly in the cost-stack methodology.[102]

7.3 Final determination

7.3.1 Bad and doubtful debt

Since DMO 5 stakeholders pushed for the AER to base our bad and doubtful debt calculations on more accurate and granular data available. As outlined in the draft determination, we have now updated our approach to use allowance figures for residential and small business based on the weighted average of the actual bad and doubtful debt data, available in the ACCC's Inquiry into the National Electricity Market Report.

As outlined in the draft determination, the increased granularity of the ACCC's disaggregated data also allows us to consider bad and doubtful debt costs on a state-by-state basis.

Based on the limited feedback received to the draft determination on this point, it appears that retailers are supportive of our current approach. We intend to continue using this this more accurate data set.

---

98 ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

99 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 10.

100 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 10.

101 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 10.

102 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p. 3.

We acknowledge consumer group concern on the lack of clarity in the method of calculation for bad and doubtful debt. As noted in more detail above, for the Inquiry into the National Electricity Market report, the ACCC considers the reported bad debt costs (including doubtful debts) that retailers determine. The allowance for bad debt costs is specifically determined in accordance with an expected credit loss impairment model prescribed in AASB 9 Financial Instruments.[103] We acknowledge that a number of macro-economic factors (such as unemployment, interest rates, wages and other economic data) may lead to material differences between the provisions made by a retailer and the actual costs they end up facing for unrecovered debt. Despite these possible differences we maintain our confidence that the data set being used represents the most accurate information available.

In Table 7.1 we have calculated a weighted average cost of bad and doubtful debt for residential and small business customers for DMO 6 compared with DMO 5 (both of which represent a state-based value).

Table 7.1 Estimated costs due to bad and doubtful debt

Distribution region	Customer type	DMO 5 bad and doubtful debt cost (per customer/annum)	DMO 6 bad and doubtful debt cost (per customer/annum)	Year-on-year difference
Ausgrid	Residential with and w/o CL	$19	$30	$11
	Small business w/o CL	$40	$65	$25
Endeavour Energy	Residential with and w/o CL	$19	$30	$11
	Small business w/o CL	$40	$65	$25
Essential Energy	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
SA Power Networks	Residential with and w/o CL	$29	$40	$11
	Small business w/o CL	$32	$52	$20

Note: This table compares year on year movements in state based bad and doubtful debt costs which were published by the ACCC in its December 2023 report. The bad and doubtful debt costs used in DMO 5 were NEM

103 Australian Accounting Standards Board, Financial Instruments AASD9 2014.

wide costs because state-based costs were not available at that time. The DMO 6 cost assessment model sets out both the DMO 6 and DMO 5 values for bad and doubtful debt and other cost items.
Source: ACCC, Inquiry into the National Electricity Market Report - December 2023.

7.3.2 Smart metering costs

Historic versus projected

We acknowledge the AEC's position that a historical approach for determining smart meter costs may disincentivise smart meter deployment due to possible inaccuracies. Despite this risk, we remain confident that using historic installation data is more accurate than any forecasting approach.

We also note the AEMC's 5-year schedule set for smart meter deployment will likely require a doubling of the current rate of installations from DMO 7 onwards and remain confident that retailers will increase their smart meter deployment.

In the meantime, we consider the historical approach to be more accurate than forecasting, at least until formal legacy meter retirement plans are in place for DMO 7. We will continue the current approach of using historic installation data in our calculations, as proposed in the draft determination.

Up-front fees

We acknowledge the government and consumer groups positions that the inclusion of up-front smart meter fees could result in over-recovering costs. The issue of over-recovery has been considered over the past 2 DMO decisions, including our efforts to refine the approach to provide stakeholders with greater detail on the extent to which retailers recover advanced meter costs from up-front fees.

We remain confident that the risk of over recovery due to charging up-front fees is minimal. From responses to our smart meter information requests, and consultation with retailers, we understand that few retailers currently choose to levy these charges to customers. In response to the South Australian Department for Energy and Mining who questioned why we changed our position on this issue,[104] we confirm that once assured of the minimal risk for customers, we prioritised our focus on ensuring that the majority of retailers solely relying on the DMO's metering allowance are not disadvantaged because of any under-recovery of costs.

In addition to this we note the AEMC recommends transitional rules that prohibit retailers from charging up-front costs (or exit fees) for meter replacements under the acceleration program, we envisage that this will not be the case for DMO 7.[105]

We intend to continue the approach from the draft determination of not subtracting up-front fees in our smart meter calculations. This will result in increases in the smart meter allowance of between $0.34 and $1.76 for residential customers and $1.31 and $3.10 for small business customers compared to an approach that does subtract up-front fees (depending on region).

[104] South Australian Department for Energy and Mining, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

[105] AEMC, Final report metering review, 30 August 2023.

Methodology update

We acknowledge EnergyAustralia's position that the AER's current approach proposed in the draft determination does not reflect the NSW distribution regions' approaches to recovering metering costs, and their alternative approach to calculating the smart meter allowances in response to network tariff metering changes in NSW.[106]

Retailers incur both accumulation metering costs (managed by the DNSP) and smart meter costs (managed by the retailer). The DMO price includes full recovery of accumulation metering costs in the network sub-component:

- in Ausgrid, Energex and SA Power Networks, this will be the ACS metering charge
- in Endeavour Energy and Essential Energy, this is included in the SCS network costs.

The DMO price also includes a 'smart meter allowance', which is designed to compensate retailers for the additional metering costs they incur above the ACS legacy metering charge already provided to them in the network cost component and ultimately the DMO price. How this allowance is calculated varies across the different regions.

As pointed out by EnergyAustralia, the proposed changes (outlined in 7.2.2) set for the recovery method for legacy accumulation meter costs in 2024–25 onwards in NSW will impact how retailers are charged. The changes in Ausgrid's network will mean all smart meter customers (except a small proportion relating to new connections) will incur the full ACS charge instead of just the capital subcomponent. In comparison, the changes in Endeavour Energy and Essential Energy's networks will mean that retailers will incur the same legacy metering costs (as part of SCS) regardless of whether a customer has a smart meter or accumulation meter installed.

We have updated the smart meter allowance methodology to reflect the changes in how legacy metering costs are recovered by distribution businesses. Appendix B sets out the calculation of the smart meter allowance in greater detail.

SA Power Networks and Energex remain on an existing regulatory period, so the older method remains valid in those jurisdictions. It is envisaged that these jurisdictions will change next year when their network determinations reset. Similarly, when that occurs, we expect that the DMO 7 would need to reflect the revised smart meter approach for South Australia and SE Queensland.

Cost of capital

As proposed from the draft determination, to cover the identified difference between the historical and forecast rates of installation we have added in a cost of capital allowance, which will cover the difference between our assumption of actuals and the projected rollout.[107] We intend to base this cost on historic installation data collected.

To further clarify our calculation, we confirm the calculation is based on a 10% weighted average cost of capital, which we consider reasonable.[108] Additionally, the projected

---

106 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 8–10.

107 AER, Default Market Offer prices, draft determination, 19 March 2024, p. 49.

108 For comparison, the independent expert report from HoustonKemp (for Brookfield's proposed takeover of Origin Energy) estimate the post company tax WACC for the retail arm of Origin Energy at 8.5% to 9%. This is found in the Origin Energy Scheme Booklet, 18 October 2023, p. 107 and p. 218.

installation number shortfall is based on the projected data from the 10 retailers who responded to our requests (making up retailers who sell to approximately 93% of customers in DMO regions).

Based on our most recent requests for smart meter installation data at 31 March 2024, we estimate the amount calculated for cost of capital (excl. GST) ranges from $0.63 (Energex and Endeavour Energy) to $0.97 (Essential Energy) for residential, and $0.33 (Ausgrid) to $0.65 (Essential Energy) for small business.

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

7.3.3 Cost-stack methodology

Responding to Energy Locals' claim that broad economic factors should be a key consideration for all elements in the cost-stack methodology, we firstly note that our retail costs calculation is not a historic account of retailer costs. We consider the most recent financial year retail cost information as the best basis from which to forecast retail costs for the DMO period. We convert the historic 2022–23 cost information into a forecast amount for the forward DMO period by applying inflation forecast to occur until the end of the DMO period. This is done to capture increases that might occur in the DMO period and to try to represent an accurate value of such costs a retailer will face.

Furthermore, labour costs account for less than half of the total subcomponents for cost to serve and half of the total subcomponents for CARC. This is a minority of the overall proportion. In relation to Energy Locals' request for concession costs to be considered in the retail cost-stack, we do not consider there to be sufficient evidence showing a real burden for retailers from this particular short-term debt. The cost of concessions is a guaranteed reimbursement from government that retailers can expect in an agreed time frame.

We have investigated this issue and recognise that no uniform process exists for concessions across the NEM jurisdictions. We understand retailers face different processes and varied time frames depending on the government agency managing the concession process. Some agencies deal solely with electricity, while some manage concessions across all utilities. Furthermore, different agencies have different verification protocols (i.e. postcode verification with market settlement and transfer solutions data).

We acknowledge that these jurisdictional differences could present a regulatory burden for retailers. However, based on our assessment of this process, we consider that the DMO determination is not an appropriate place to addressed address this cash flow issue. Rather, retailers may wish to raise their concerns with the agencies responsible for administering concessions programs.

In relation to PIAC/SACOSS/ACOSS's argument that CARC is a retail expenditure that should not be accounted for explicitly in the cost-stack methodology, we note that the regulations require us to have regard to acquisition costs. Therefore, we continue to deem it appropriate to explicitly include them in the cost-stack methodology. We note that the analysis of margins in our draft decision, as well as margins observed by ACCC in its December 2023 and prior 'cost stack' reports are net of average retailer CARC costs. It would be possible to estimate margins before CARC is considered, but this approach would result in margins higher than 6% and 11%.

This approach has been used since DMO 4. The approach has an established transparency, which we consider important.

7.4 Summary of determinations for retail costs

Table 7.2 and 7.3 set out the components for our cost build-up approach in DMO 6.

Table 7.2 Residential retail costs (excluding GST)

Distribution region	Retail and other costs sourced from ACCC	Smart meter costs	Bad and doubtful debt costs	Capital allowance (smart meters)	Forecast CPI adjustment	Total	Year-on-year difference
Ausgrid	$142.00	$37.95	$30.00	$0.66	$15.00	$225.61	17.7%
Endeavour Energy	$142.00	$55.61	$30.00	$0.63	$16.25	$244.49	24.2%
Essential Energy	$142.00	$56.19	$30.00	$0.97	$16.32	$245.48	27.4%
Energex	$142.00	$39.13	$24.00	$0.63	$14.65	$220.41	15.8%
SA Power Networks	$146.00	$42.94	$40.00	$0.71	$16.35	$246.00	25.0%

Source: AER Default market offer 2024–25 cost assessment model.

Table 7.3 Small business retail costs (excluding GST)

Distribution region	Retail and other costs sourced from ACCC	Smart meter costs	Bad and doubtful debt costs	Capital allowance (smart meters)	Forecast CPI adjustment	Total	Year-on-year difference
Ausgrid	$183.00	$28.58	$65.00	$0.33	$19.72	$296.63	24.2%
Endeavour Energy	$183.00	$39.76	$65.00	$0.49	$20.53	$308.78	29.7%
Essential Energy	$183.00	$38.88	$65.00	$0.65	$20.48	$308.01	37.4%
Energex	$183.00	$35.02	$42.00	$0.49	$18.55	$279.06	35.8%
SA Power Networks	$183.00	$34.61	$52.00	$0.49	$19.24	$289.34	31.3%

Source: AER Default market offer 2024–25 cost assessment model.

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 supplying electricity. The DMO price has also been set such that it meets and appropriately balances the policy objectives[109] 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. A retail allowance was included in DMOs 1-3 within the 'residual' component, which combined this with retail costs.

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.

Our DMO 6 draft determination proposed to split the retail allowance into separate efficient margin and competition allowance components.

8.1 Draft determination

8.1.1 Retail margin

In our draft determination, we decided setting retail margins as a percentage of the DMO price (before a competition allowance) was the most appropriate approach. We decided on efficient retail margins of 6% for residential customers and 11% for small business customers.

8.1.2 Competition allowance

We determined competition allowances of $66 for residential DMO prices and $291.50 for small business DMO prices. The competition allowances were determined based on the range of costs to serve per customer reported by retailers as part of the ACCC National Electricity Market Inquiry. The DMO retail cost component discussed in chapter 7 allows retailers with average costs to serve to achieve margins of 6% for residential customers and 11% for small business customers. The inclusion of an additional competition allowance would allow retailers with higher-than-average costs to serve to achieve these same margins when selling at the DMO price.

Our draft determination reflected our view that cost-of-living pressures, inflation and electricity affordability are relevant matters that the AER must have regard to in determining

109 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, June 2018; the Explanatory Statement accompanying the Regulations, 2019.

DMO prices under s 16(4)(d) of the Regulations. Our draft determination noted in DMO 6 that the external economic conditions are extremely tough for consumers. There are persistent price pressures in the economy demonstrated by headline CPI materially exceeding the RBA target band of 2–3% annual growth on a sustained basis since December quarter 2021. Inflation also contributes to growth in the network and retail operating cost elements of the DMO cost stack.

Our draft determination had regard to the impact of economic conditions on energy consumers, including increased inflation, cost-of-living pressures and electricity affordability. We considered it is appropriate for the 2024–25 DMO price give greater weighting to the DMO price protection objectives and not include the competition allowance in DMO 6.

8.2 Stakeholder views

8.2.1 Retail allowance approach to best balance DMO objectives

Origin Energy, Energy Locals, ENGIE and PIAC/SACOSS/ACOSS (in their joint submission) all supported the separation of the retail allowance into separate retail margin and competition allowance components.[110]

The AEC supported the AER developing a methodology for determining the retail margin and advocated for the AER to remain consistent in applying the methodology.[111]

Of all stakeholders whose submissions discussed the retail allowance component of the DMO 6, only Alinta Energy explicitly stated it did not support the AER's decision to separate the retail margin and the competition allowance as it considered the mechanism for re-introducing the competition allowance unclear.[112]

8.2.2 Retail margin

Origin Energy supported setting the residential retail margin at 6%,[113] and AGL and ENGIE supported the AER's decision to apply a percentage margin rather than a dollar amount.[114] ENGIE also pressed for the AER to provide regulatory certainty by maintaining the percentage margin over a period longer than the term of each DMO.[115]

PIAC/SACOSS/ACOSS considered that if the 6% retail margin was to be implemented, it should negate the need for any further energy retailer claims for additional cost allowance elsewhere.[116] They also disagreed that thin retail margins will result in energy retailers exiting the marketplace.[117]

---

110 Energy Locals, *Submission to DMO 6 draft determination*, 11 April 2024, p. 8.; ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.; Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 7; PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p. 5.

111 AEC, *Submission to DMO 6 draft determination*, 13 April 2024, p. 6.

112 Alinta Energy, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 2–3.

113 Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 8.

114 AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.; ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

115 ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

116 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p. 6.

117 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p. 6.

ECA did not consider prior retail allowances of 10% and 15% for residential and small business customers, respectively, to be justifiable or fair.[118] They considered a lower margin, such as 6% as proposed in the draft determination, is sufficient for competition – noting that competition remains in jurisdictions where a lower retail margin is used, notably Victoria, where the retail margin is currently set at 5.3%.[119]

The South Australian Department for Energy and Mining suggested that the AER assess future retail margins on a state-by-state basis (similar to the approach for retail costs). The department's submission noted that the analysis carried out in the DMO 6 draft determination demonstrated that inferred margins vary from state to state.[120]

AGL, Origin Energy and ENGIE supported separate margins for residential and small business customers,[121] whereas ECA opposed separate higher margins in the small business DMO prices.[122]

These sentiments were replicated through the DMO 6 stakeholder workshops, as facilitated by the AER, and through several meetings that were held between the AER and individual stakeholders on request.

8.2.3 Competition allowance

Approach to determining the competition allowance

ENGIE did not support the AER's decision to set this allowance on a dollar per customer basis and considered setting this allowance on a percentage basis would be better to ensure that it would increase or decrease in line with other cost-stack components.[123] Origin Energy questioned how the $66 per residential customer was calculated because no detail was provided in the DMO 6 draft determination.[124]

EnergyAustralia argued that the proposed competition allowance may not adequately account for some retailers' higher costs to acquire and retain customers, and that excluding these costs risks incentivising short-term cost cutting measures. It also considered that this could lead to a decline in service quality or less diverse range of offerings.[125]

Decision to exclude the competition allowance

Origin Energy, Energy Locals, ENGIE and the AEC did not support the decision to exclude the competition allowance based on the AER's assessment of current economic conditions affecting both the market and customers. [126] Nor did EnergyAustralia or Momentum Energy,

118 ECA, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

119 ECA, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

120 South Australian Department for Energy and Mining, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 2–3; AER, *Default market offer prices 2024–25: draft determination*, 19 March 2024, pp. 60–64.

121 AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3; ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3; Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p.8.

122 ECA, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

123 ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 6.

124 Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 1.

125 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, p. 5.

126 Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 1; Energy Locals, *Submission to DMO 6 draft determination*, 11 April 2024, p. 8; AEC, *Submission to DMO 6 draft determination*, 13 April 2024, p. 6.

who were of the opinion that the omission of the competition allowance is a shift in policy by the AER and a divergence from the original objectives of the DMO.[127] 1st Energy sought greater clarity on the AER's rationale for this decision.[128]

1st Energy, Momentum Energy and EnergyAustralia were of the view that omitting the competition allowance from DMO 6 signals that competition and investment by energy retailers is not supported by the AER. These submissions considered this decision would likely result in contraction of the energy market in line with the erosion of retail margins by influences such as understated environmental costs and negative solar exports, as well as removal of lower priced and innovative market offers that have benefited customers in the past.[129]

The Australian Energy Council (AEC), AGL and Origin Energy submitted that the risk of increasing electricity prices is primarily driven by the forecast increase in the network costs component of the DMO as a consequence of the transition to renewables and the costs associated with this transition. They noted this is particularly shown by the network costs component being the largest cost contributor of the DMO 6.[130] This sentiment was supported by several other retailers during retailer discussions facilitated by the AER.

AGL, Energy Australia and Origin Energy all submitted that the AER's retail margin 'squeeze' posed a risk to energy retailers and argued this was a clear attempt to offset the aforementioned increases in network costs.[131] The AEC was of the opinion that squeezing retail margins to offset burgeoning network costs can only occur if there is something left to squeeze.[132]

Most energy retailers discussing the competition allowance component, including AGL, EnergyAustralia, Origin Energy and 1st Energy, argued that the AER should provide explicit details on the mechanism that will trigger the re-introduction of the competition allowance.[133] Others, including ENGIE and Energy Locals, suggest that once removed, it will be difficult for the AER to argue for the competition allowance to be re-introduced.[134]

The concerns in retailers' submissions were also echoed in retailer workshops and one-on-one meetings.

---

127 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, p. 4; Momentum Energy, *Submission to DMO 6 draft determination*, 10 April 2024, p. 1.

128 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 8.

129 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.; Momentum Energy, *Submission to DMO 6 draft determination*, 10 April 2024, p. 1; EnergyAustralia*, Submission to DMO 6 draft determination*, 9 April 2024, p. 4.

130 AEC, Submission to DMO 6 draft determination, 13 April 2024, p. 2; AGL, Submission to DMO 6 draft determination, 9 April 2024, p. 1; Origin Energy, Submission to DMO 6 draft determination, 12 April 2024, p. 9.

131 AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 1; Energy Australia, *Submission to DMO 6 draft determination*, 9 April 2024; p. 4, Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, p. 9.

132 AEC, *Submission to DMO 6 draft determination*, 13 April 2024, p. 2.

133 AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 4; EnergyAustralia*, Submission to DMO 6 draft determination*, 9 April 2024, p. 7; Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, pp. 8–9; 1st Energy, *Submission to DMO 6 draft determination*, 9 April 2024, p. 8.

134 Energy Locals, *Submission to DMO 6 draft determination*, 11 April 2024, pp. 8–9; ENGIE, *Submission to DMO 6 draft determination*, 9 April 2024, p. 4.

The ACCC is concerned that the approach suggested by the AER – to consider whether to re-introduce the competition allowance on a case-by-case basis – does not provide sufficient certainty to energy retailers about future DMO outcomes and may restrict new market entrants.[135] The ACCC also noted that the DMO should be set at a price level that allows efficient smaller standalone retailers to compete.[136]

Several energy retailers were also of the opinion that it is not the DMO's role to respond to specific economic conditions and compromise one party in the energy supply chain while favouring others. Origin Energy suggested there are more prudent and sustainable approaches in balancing the DMO objectives – particularly in a high-cost environment – including how any burden can be shared across the sector, as opposed to disproportionately on retailers.[137] EnergyAustralia noted that the AER's draft decision to exclude a cost provision for competition considered the impacts of inflation on network and retail costs. Their concern with this approach is that retailers bear the risk of rising network costs, which is likely to continue with the energy transition.[138] Energy Locals understands and appreciates the rising cost-of-living pressures but is also of the opinion that DMO 6 places the burden for addressing these cost-of-living pressures too squarely on energy retailers.[139] AGL adds that the best regulatory measures to address affordability, and minimise costs to consumers, is to address the regulatory and industry barriers that may prevent customers from attaining the best available market offer.[140]

One-on-one meetings held between the AER and various energy consumer groups raised cost-of-living pressures as a concern for business consumers as well as households. These challenges can lead to decreased customer traffic and, in some cases, business closures due to high energy bills. The situation is being exacerbated for businesses due to rising costs across various aspects of the supply chain, including insurance, energy and wages. Some businesses also experience difficulties in passing all increased expenses on to customers.

In their combined submission, PIAC/SACOSS/ACOSS challenged the proposition that a competition allowance is, at all, necessary, and supported the AER's decision to not include it in the DMO 6 prices. They considered that it is not an effective method of inducing innovation or competition into the energy market to the benefit of customers and believed it to be an increasingly unjustifiable and unfit method of protecting customers, especially in the current financial environment.[141] Additionally, they were concerned about the impact on customers when the competition allowance is re-introduced.[142] ECA supported the AER's decision to omit the competition allowance from DMO 6 and also suggested, as evidenced by the presence of competition in other jurisdictions that do not include a competition allowance equivalent, most notably Victoria, there will be no need to include it in the future.[143] The South Australian Department for Energy and Mining supported the AER's decision not to include the competition allowance in DMO 6 and indicated it would be disappointed if the

---

135 ACCC, *Submission to DMO 6 draft determination*, 9 April 2024, p. 2.

136 ACCC, *Submission to DMO 6 draft determination*, 9 April 2024, p. 1.

137 Origin Energy, *Submission to DMO 6 draft determination*, 12 April 2024, pp. 1–2.

138 EnergyAustralia, *Submission to DMO 6 draft determination*, 9 April 2024, p. 4.

139 Energy Locals, *Submission to DMO 6 draft determination*, 11 April 2024, p. 12.

140 AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

141 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p.5–6.

142 PIAC/SACOSS/ACOSS, *Submission to DMO 6 draft determination*, 11 April 2024, p. 6.

143 ECA, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 1–2.

future inclusion of the competition allowance erodes any benefits of any future wholesale and network cost reductions.[144]

8.3 Final determination

8.3.1 Retail allowance approach to best balance DMO objectives

Our final determination maintains the draft determination approach of splitting the retail allowance into separate efficient margin and competition allowance components.

Separating the retail allowance into separate components is appropriate and has many advantages:

- It provides greater transparency on the individual components within the DMO price, particularly the direction in the Regulations that the DMO allows retailers to achieve a reasonable profit and the component of the DMO reflecting the competition objectives.
- It allows the efficient margin component to function as a percentage of costs and the revenue at risk. This approach to margin is consistent with other regulatory decisions, including by ESC, Office of the Tasmanian Economic Regulator and Independent Competition and Regulatory Commission.
- It allows the competition allowance to reflect differing economies of scale achieved by smaller and newer entrant retailers by considering the ranges in retailers' costs to serve customers. We consider this a refinement to our approach, which previously followed movements in other DMO cost components as part of the retail allowance percentage.
- By separately determining efficient margin and competition allowance components, the AER has more flexibility to balance the DMO objectives and other matters the AER considers relevant to its determination.

8.3.2 Retail margin

Our final determination maintains the 6% and 11% margins proposed in the draft determination for residential and small business customers, respectively.

These margins are lower for most customers compared to the DMO 5 determination and are situated within the ranges of margins inferred in analysis in the draft determination. This analysis has had regard to the prices electricity retailers charge,[145] and the costs that retailers incur when supplying electricity, including wholesale costs,[146] distribution and transmission costs,[147] the costs of complying with Commonwealth and jurisdictional laws,[148] cost of acquiring small customers,[149] and the costs to serve.[150] This analysis included:

- retailer margins inferred from customer weighted average prices retailers charge market offer customers

---

144 South Australian Department for Energy and Mining, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

145 Regulations, s16(4)(a).

146 Regulations, s16(4)(c)(i).

147 Regulations, s16(4)(c)(ii).

148 Regulations, s16(4)(c)(iii).

149 Regulations, s16(4)(c)(iv).

150 Regulations, s16(4)(c)(v).

- retailer margins inferred from offers to new customers
- other regulatory determinations of efficient margins
- ACCC analysis of actual retailer margins in its December 2023 report.

We have not received any updated information or evidence from other stakeholders suggesting other values are more appropriate.

We disagree with ECA that margins should be uniform across residential and small business customers. We consider these customer groups present distinct costs and risks to retailers that merit separate margins. Maintaining these separate margins in residential and small business DMO prices better meets the requirement in the Regulations that retailers can make a reasonable profit for each separate customer type.

If we instead developed a single weighted average margin across both residential and small business customer types, this could underestimate small business margins and overestimate residential margins. This outcome would not as closely align with the Regulations, which contemplates distinct types of small customers. Such an approach could dissuade retailers intending to focus or specialise on retailing to the small business segment and could result in fewer choices for small business customers.

We acknowledge the South Australian Department for Energy and Mining submission that noted that the analysis of inferred margins varies from state to state. However, we remain of the view that it is appropriate for margins to be consistent for a customer type across all regions, and have maintained the customer weighted average margins of 6% and 11% for residential and small business customers. As noted in our draft determination,[151] this approach addresses concerns of interregional inequity while recognising the different risks and observed margins achieved for residential and small business segments.

On the basis of the information and analysis we have carried out to date, we propose to maintain these margins in future DMO prices, but we will continue to carry out inferred margin analysis similar to the DMO 6 draft determination to assess whether these settings remain appropriate.

8.3.3 Competition allowance

Approach to determining the competition allowance

We have decided to maintain the same approach for quantifying the competition allowance as proposed in the draft determination. This approach has regard to the range of per-customer costs to serve among the retailers that report to the ACCC and results in competition allowances of $66 and $291.50 (inc. GST) for residential and small business DMO prices respectively.

On the basis of the information and analysis we have carried out to date, we do not consider it appropriate that the competition allowance consider costs to acquire and retain customers, as suggested by EnergyAustralia. Average costs to acquire and retain customers are already explicitly included in the DMO price because these costs fall within the ‘retail and other costs’ component included in the DMO price.

---

151 AER, *Default market offer prices 2024–25: draft determination*, 19 March 2024, p. 62.

Our method for determining the competition allowance values uses commercially sensitive information, including individual retailer per-customer costs to serve, as well as other measures of efficiency and profitability. Providing further detail as requested by Origin Energy in its submission might risk the confidentiality of the information used.

Decision to exclude the competition allowance in DMO 6

We have decided to exclude the competition allowance. This decision has been made with regard to the economic conditions, cost-of-living pressures and energy affordability issues experienced by consumers. These are matters that we consider relevant under s 16(4)(d) of the Regulations and had regard to in making our determination.

A number of retailers have contended that this decision marks a departure from the DMO objectives and does not incentivise retailers to compete, innovate and invest in the electricity market. Some stakeholder feedback suggested that the AER is managing increased costs as a result of higher network charges by reducing the retailer margin.

The AER has not chosen to disapply the competition allowance in DMO 6 to offset increases in network costs. Rather, we consider that excluding the competition allowance for DMO 6 achieves the best balance of the DMO objectives and takes into account submissions received. Our decision, which includes efficient margins in the DMO price, also meets our regulatory requirement that the DMO price allows retailers to achieve a reasonable profit.

We consider that the DMO prices without a competition allowance still allows retailers to compete. The DMO prices allow retailers with average costs to serve to still make a margin of 6% for residential customers and 11% for small business customers. Retailers that have higher costs may not receive the full margins. However, the retail operating costs provided for in DMO 6, and the margins, are higher than those in the Victorian Default Offer.

As noted in ECA's submission, competition has persisted in jurisdictions that have set retail margins in regulatory determinations lower than the 6% and 11% margins used in our DMO 6 determination – most notably Victoria. This suggests that retailers will be able to continue to compete in DMO regions without the inclusion of a competition allowance.

The analysis set out in the draft determination found a large range in inferred margins between 2.8% and 6.9% for residential customers and 6.8% and 13.6% for small business customers. The values of 6% and 11% are within these ranges, but exceed the midpoint by approximately 1 percentage point. We consider this reflects some conservatism and is appropriate, particularly in the context of the decision to exclude a competition allowance.

We also note ACIL Allen's additional retail margin analysis examining market offer prices[152] among small, medium and large retailers. This has found that smaller retailers offer the lowest prices for 12 of the 15 DMO market segments and the second lowest price in the remaining 3 DMO market segments. This suggests to us that smaller retailers competing for new customers are not price constrained by the DMO and would continue to not be price constrained by a DMO price that does not include a competition allowance.

We do not consider that the decision to exclude the competition allowance to address cost-of-living pressures and difficult economic circumstances disproportionately burdens retailers instead of networks, generators and other participants. The competition allowance

---

152 ACIL Allen, *Default Market Offer 2024–25 Methodologies for estimating the retail allowance and estimated values*, May 2024, Appendix B.

represents an additional amount in DMO prices to further incentivise competition and consumer engagement. Unlike other elements of the DMO cost-stack, it is not an allowance reimbursing retailers for a cost of supplying electricity. Its exclusion from the DMO price does not impose or burden retailers with an unrecovered cost in supplying electricity.

We acknowledge retailers' and the ACCC's call for regulatory certainty on the framework for the AER determining whether to include or exclude the competition allowance in future determinations. We understand it is important to provide clear signals to the market to facilitate market participates to continue to compete, invest and innovate.

In the absence of any changes to the DMO Regulations, the AER's framework for determining whether to include or exclude the competition allowance will be based on economic conditions.

The primary factor we will use is cost of living and price pressures as measured by 12-month movements in the CPI, reported on quarterly by the Australian Bureau of Statistics. Where CPI is materially above the RBA's target band for a sustained period, we will not apply the competition allowance to prioritise consumer protection. In making this decision we will also have regard to the state of retail competition.

We consider that this approach is transparent, objective and provides some predictability about how we will respond to economic conditions. It relies on publicly available Australian Bureau of Statistics inflation data provided on a quarterly basis. This allows the AER and stakeholders to regularly assess economic conditions and whether the competition allowance would be included or excluded for upcoming DMO determinations, including at issues paper and draft determination stages.

8.4 Summary

Tables 8.1 to 8.3 set out the retail margins in DMO prices in percentage and dollar terms.

Table 8.1 Retail margins in DMO prices for residential without CL

Distribution region	Retail margin	Retail margin (inc. GST)
Ausgrid	6%	$108.61
Endeavour Energy	6%	$132.56
Essential Energy	6%	$149.92
Energex	6%	$123.11
SA Power Networks	6%	$132.97

Source: AER Default market offer 2024–25 cost assessment model, CL: controlled load.

Table 8.2 Retail margins in DMO prices for residential with CL

Distribution region	Retail margin	Retail margin (inc. GST)
Ausgrid	6%	$149.72
Endeavour Energy	6%	$167.22
Essential Energy	6%	$175.05
Energex	6%	$144.00
SA Power Networks	6%	$164.74

Source: AER Default market offer 2024–25 cost assessment model, CL: controlled load.

Table 8.3 Retail margins in DMO prices for small business

Distribution region	Retail margin	Retail margin (inc. GST)
Ausgrid	11%	$505.69
Endeavour Energy	11%	$484.77
Essential Energy	11%	$629.02
Energex	11%	$467.06
SA Power Networks	11%	$587.10

Source: AER Default market offer 2024–25 cost assessment model, CL: controlled load.

9 Annual usage amounts, and timing and pattern of supply

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

9.1 Draft determination

9.1.1 Annual usage amounts

After we had considered stakeholder submissions to the issues paper and the available information at that time on annual usage, we deemed the amounts were still broadly representative of residential and small business customer usage. Our draft determination position was to retain the current annual usage benchmarks for residential and small business customers, including the current controlled load amounts, for DMO 6.

9.1.2 Timing and pattern of supply

The DMO 6 draft determination maintained our approach for timing and pattern of supply from DMO 5 and updated the usage profiles using new interval meter data obtained from AEMO.

9.2 Stakeholder views

9.2.1 Annual usage amounts

AGL noted that due to the differing types of energy retailers present in the current market and the various customer types and usage patterns, it is impossible for a single DMO price for residential (and another single price for small business customers) to accurately reflect the cost of supply under each of the available customer arrangements.[153] Similarly, ECA noted the changing energy market, the emergence of new energy products and services and changing usage behaviour has complicated the determination of the annual usage amount.[154]

9.2.2 Timing and pattern of supply

Energy Locals suggested that the AER introduce usage variations for weekdays versus weekends and seasonal considerations due to the evolving usage patterns of customers. They noted that factors such as the adoption of controlled load appliances, solar panels, batteries and electric vehicles have all contributed to this shift.[155]

Energy Locals and ECA were concerned that advertised discounts – calculated by comparing the annual price of a TOU offer based on the DMO usage pattern to the reference

153 AGL, *Submission to DMO 6 draft determination*, 9 April 2024, p. 3.

154 ECA, *Submission to DMO 6 draft determination*, 9 April 2024, p. 6.

155 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 10.

price – could be inaccurate for a number of customers. This may lead to higher than anticipated bills if more energy is used in peak times than in the AER's time of use pattern.[156]

ECA also expressed concern that some standing offer customers could be on demand tariffs that are not protected by the DMO and noted that more customers are on underlying cost reflective network tariffs under tariff assignment policies.[157] ECA also considered that if these tariffs were covered by the DMO, developing consumption patterns and reference prices for these tariffs would be exceedingly difficult.

Energy Locals cited the AER's quarterly retail performance data that found solar adoption has increased by 4% in the last year. As a result, customers are shifting to time of use network tariffs and then to cost-reflective retail tariffs to benefit from their solar exports. Consequently, Energy Locals believed that customers will be increasingly required to adjust their energy consumption patterns to maximise their investment in solar energy.[158]

Energy Locals encouraged the AER to consider the impact electric vehicles will have on future household energy consumption patterns to pricing assumptions.[159]

Additionally, Energy Locals was of the opinion that not all customers will enter their National Meter Identifier when using comparison sites such as Energy Made Easy, which can have significant implications for the accuracy of the energy cost comparisons provided by such platforms.[160]

9.3 Final determination

9.3.1 Annual usage amounts

The DMO 6 final determination position on annual usage is to retain the current annual usage benchmarks for residential and small business customers, including the current controlled load amounts.

We acknowledge stakeholders' points that the energy transition, including uptake of solar, smart appliances and electric vehicles, introduces greater variation in how electricity is used and annual consumptions. Nevertheless, s6(2) of the Regulations require us to determine a single annual usage amount that is broadly representative for each customer type, which are:

- residential without controlled load
- residential with controlled load
- small business without controlled load.

For the residential customer types, this usage amount must encompass households of various family sizes, with and without solar, smart appliances, electric vehicles and access to alternative fuels, such as a gas connection.

156 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 10; ECA, *Submission to the DMO 6 draft determination*, 9 April 2024, p. 6.

157 ECA, *Submission to the DMO 6 draft determination*, 9 April 2024, p. 6.

158 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 10.

159 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, p. 10.

160 Energy Locals, *Submission to DMO 6 draft determination*, 9 April 2024, pp. 10–11.

Having regard to the most recent available information on annual usage in our draft determination,[161] we consider the annual usage amounts are still broadly representative of residential and small business customer usage. Using ACCC analysis of electricity bills, we found our assumed annual usage amounts sit within the interquartile range of consumption.[162]

Having regard to the most recent available information, we consider altering our approach would add complexity without providing major benefits to stakeholders. For example, increasing the assumed annual usage amounts from DMO 5 to DMO 6 would in turn increase the DMO price associated with that assumed annual usage. This would make it more difficult to compare annual changes in the DMO price due to changes in DMO cost components. Customers engaging in the market may also find it more difficult to compare prices, as the DMO reference price would increase and could create a perception that new market offers provide worse value for money than prior market offers calculated under a lower usage amount. We believe the current approach results in appropriate usage assumptions and provides consistency and transparency by adhering to the established methodology.

9.3.2 Timing and pattern of supply

The DMO 6 final determination retains our approach to timing and pattern of supply from DMO 5 and uses updated usage profiles sourced from new AEMO interval meter data.

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, for each residential customer type in each region we will:

- 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 to describe the pattern of usage
- update the 24-hour usage profile using the AEMO interval meter data for the 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). We propose to continue to update the profiles with new data each year.

We acknowledge Energy Locals' and ECA's concerns about the limitations of a single usage pattern representing all residential customers in a region. These submissions note the challenges for customers on TOU offers that consume higher than average proportions of energy within peak periods to select the most suitable offer based on the reference price and underlying usage assumptions.

---

161 AER, *Default market offer prices 2024–25: Draft determination*, 19 March 2024, pp. 71–75, Appendix E.

162 AER, *Default market offer prices 2024–25: Draft determination*, 19 March 2024, pp. 71–72.

However, we do not consider that any additional benefit from providing further detail to the pattern of usage, such as separate season and/or weekday/weekend consumption shapes would outweigh the additional complexity, burden and costs imposed on retailers in developing compliant time of use standing offers and accurately calculating market offer discounts relative to the reference price.

Further disaggregated consumption patterns would continue to be derived from AEMO's Market Settlement and Transfer Solutions interval consumption data. In order to be broadly representative of all residential customers, this data would be aggregated across households with and without solar, EVs, smart appliances, etc. to produce average weekday/weekend and seasonal patterns. Individual household patterns, including the proportion of usage falling into peak periods, and the suitability of any particular time of use offer, would still depend on individual household characteristics and likely differ from these additional consumption profiles.

We note ECA's concerns about the possibility of standing offer customers to be on demand tariffs that are not covered by the DMO and its pricing protections. We agree that determining DMO prices and broadly representative patterns of consumption for demand tariffs would present many challenges and could be of limited relevance to customers. We consider that policymakers are best placed to assess the extent of this issue and whether changes to the regulatory framework are appropriate.

We continue to recommend customers with smart meters take advantage of their features and enter the National Meter Identifier (NMI) on comparison websites such as Energy Made Easy (EME) when shopping around. This will identify the best offer given that customer's unique usage amount over the past 12 months and other factors in developing a more tailored estimate of annual bills than the usage amounts and pattern in the DMO determination.

We are encouraged to see that a growing number of customers are using this feature on the EME website, with a sustained increase from around 20,000 comparisons in January 2023 to a monthly average of around 55,000 NMI-based comparisons across the 2023–24 financial year to April 2024.

10 Appendices

Appendix A – Listening report

Appendix B – Smart meter costs

Appendix C – DMO Legislative Instrument 2024–25

Appendix D – DMO 5 to DMO 6 price movement

Appendix E – State-based comparison

Appendix F – Summary of cost stack price movements

A. Listening report

AUSTRALIAN ENERGY REGULATOR

23 MAY 2024

DMO 6 Listening Report

Our process – moving from draft to final determination

Our approach to engagement for DMO 6 involved engaging with a broad range of stakeholders through targeted consultation activities.

This involved inviting public written submissions, the opportunity for one-on-one discussions and for the second year hosting in-person workshops with retailers. Through these discussions and workshops, we have actively broadened our efforts to engage with stakeholders in an open discussion format. The consultation approach for DMO 6 has:

- created the opportunity for stakeholders to have open discussions with the AER and ask questions or seek guidance in advance of written submissions
- allowed the AER to directly hear key stakeholder views in advance of receiving written submissions
- provided an opportunity for stakeholders who choose not to provide a written submission to have input into our DMO methodology considerations
- ensured that our rationale and decision-making process is transparent.

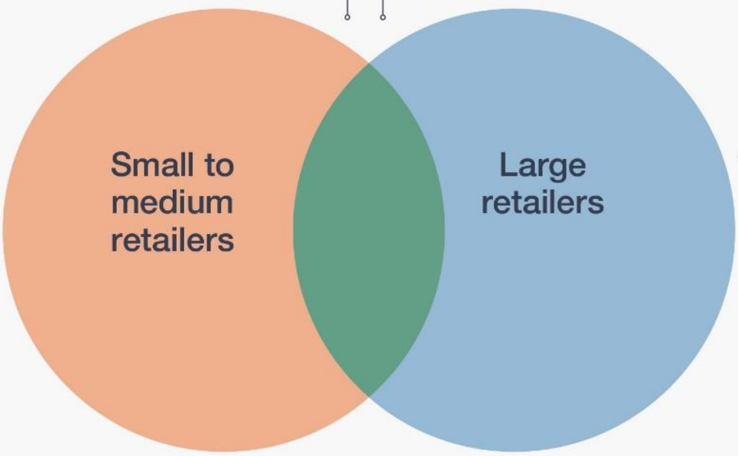
The specific topics highlighted in this Listening Report represent the verbal stakeholder feedback received, not the written submissions which have been summarised in the final determination.

Engagement timeline since draft determination

19 March	Draft determination released for consultation
25–26 March	Two in-person retailer workshops
25 March – 9 April	One-on-one meetings with retailers and consumer groups
9 April	Written submissions received
23 May	Final determination published

Wholesale

Methodology and blended load profiles



Small to medium retailers

- There's a cost exposure for retailers when exporting to negative spot prices.
- Large retailers have more capital to employ load-shifting measures and have a flater load profile; it's different for newer entrants.

Agreement

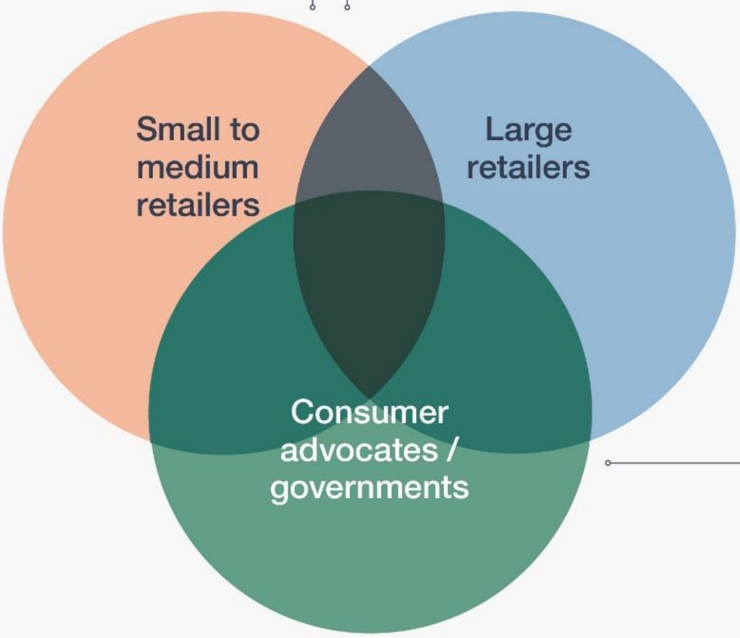
- Agreed with decision to include interval meter data but recommended solar exports are included.
- Load-shifting measures don't entirely counter the daytime carve-out.

Large retailers

- The methodology should be a broad reflection of ways retailers manage risk.
- Load-shifting measures are nascent and shouldn't be held as standard practice for the purposes of the DMO.
- The DMO sets a level of cost for a representative retailer. The aim of incentive regulations is to reward.

Retail

Competition allowance



Small to medium retailers

- Removing the competition allowance could potentially benefit larger retailers.

Retailer agreement

- Raised concerns about future regulatory decisions regarding the conditions for the return of the allowance and suggested that removing it is hindering competition.

All stakeholder agreement

- Acknowledges cost-of-living concerns in the context of electricity prices.

Large retailers

- Competition allowance is one of the smallest components of a customer bill, therefore any change made to this will have minimal impact. Network costs however are a greater component and burden for a consumer bill.

Consumer advocates/ governments

- Advocates for and supports the exclusion of the competition allowance.

Load profiles - NSLP

- Retailers considered the adjusted Net System Load Profile (NSLP) would better reflect the load shape a retailer hedges against in practice and questioned why the non-adjusted NSLP would be used for the midpoint considering the known issues with the data.
- Retailers noted that all retailers adopt different hedging strategies, and that the NSLP is a proxy and just one input into a retailer's approach to hedging.

Smart meters

- Stakeholders supported the AER's decision to include a capital allowance.
- They sought clarity on how the capital allowance has been calculated. Questioned whether the allowance reflects a financing cost and/or time value of money.
- Retailers may roll out beyond forecast installations. They feared the capital allowance would not suffice. Retailers' rollout efforts could be discouraged by any loss.

Thank you for your feedback

19 stakeholders spoken to through workshops and one-on-one meetings to gather feedback

16 written submissions received for the draft determination

22 written submissions received for the issues paper

7 one-on-one meetings conducted with stakeholders between draft and final including retailers and consumer representatives and government

13 retailers attended the draft determination workshops, accounting for over 90% of residential and small business customers across NSW, Queensland and South Australia

Our continued engagement

We will continue our stakeholder engagement activities as part of our annual DMO process, engaging with a wide range of stakeholders. Our final determination details how we have considered the views of our stakeholders in detail, including written submission feedback, and our reasoning behind each aspect of the determination.

We would like to thank participants for their involvement in this process and look forward to engaging further as part of DMO 7.

Who did we hear from?

Written feedback

We invited stakeholders to publicly contribute to our consultation process, and received 16 written submissions from the following stakeholders:

- Australian Competition and Consumer Commission
- AGL
- Alinta Energy
- Australian Energy Council
- Energy Consumers Australia
- ENGIE
- Energy Locals
- EnergyAustralia
- Momentum Energy
- Nick Roucek
- Origin Energy
- Queensland Minister for Energy and Clean Economy Jobs
- South Australian Department for Energy and Mining
- Public Interest Advocacy Centre/South Australian Council of Social Service/ Australian Council of Social Service
- 1st Energy

Verbal feedback

1 large retailer workshop including 7 participants	**1** small-to-medium retailer workshop with 6 participants	**7** one-on-one meetings

One-on-one meetings

We held one-on-one discussions with consumer representative groups, industry representatives, government bodies and retailers. These discussions provided insightful viewpoints that helped develop understandings of key stakeholder concerns. As these were verbal discussions, responses have not been attributed to each stakeholder by name.

Retailer workshops

We hosted two face-to-face workshops with large and small-to-medium size retailers to discuss key topics featured in the draft determination. This gave retailers the opportunity to discuss key topics featured in the paper and ask any questions to the AER staff.

Australian Government | AUSTRALIAN ENERGY REGULATOR

B. Smart meter costs

We requested retailers selling to approximately 93% of customers in DMO regions to provide the number of customers on smart meters and accumulation meters for each DMO region and customer type as at 31 March 2024, and projected installations for the midpoint of DMO 6 (31 December 2024). We also asked retailers to provide the average costs they incur per smart 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.

We have updated the calculation of smart meter allowances in Ausgrid, Endeavour Energy and Essential Energy to reflect changes to how metering costs are recovered in these regions. These approaches are set out below.

Ausgrid

In Ausgrid, the smart meter allowance will be the total smart meter costs divided by the number of all customers (both those with smart meters and legacy meters) (‘smart meter cost per customer’) minus the ACS metering charge multiplied by the proportion A% of customers that do not incur an ACS metering charge for their retailer (i.e. new connections).

$$Smart\ Meter\ Allowance = Smart\ Meter\ Cost\ per\ customer - (ACS_{metering\ total} \times A\%)$$

Endeavour Energy and Essential Energy

In Endeavour Energy and Essential Energy, the smart meter allowance is the smart meter cost per customer.

$$Smart\ Meter\ Allowance = Smart\ Meter\ Cost\ per\ customer$$

This is because retailers will incur accumulation metering charges (within the SCS) among all their DMO applicable customers regardless of whether they have a smart meter or not.

Energex and SA Power Networks

We first calculate a per-smart meter ‘shortfall’ not accounted for elsewhere in the DMO price. This is a different approach to Ausgrid and Endeavour Energy/Essential Energy, as we first work out the shortfall per smart meter, before converting an average cost across all customers as a second step.

- We calculate the average cost per-smart meter (all smart meter costs incurred divided by only smart meter customers), then subtract the entire ACS metering charge (because this is already included in the Network cost component), then add back the ACS metering capital sub-component multiplied by the proportion B% of smart meter customers for whom the retailer must continue to pay the ACS metering capital sub-component. This is because retailers selling to smart meter customers do not have to pay the opex component of the ACS metering charge, but most customers with smart meters (installed at request of the customer, ‘rolled out’ by the retailer, or replacing a faulty legacy meter) still incur the ACS metering capital sub-component.
- This gives the average ‘shortfall’ per smart meter that retailers need to pay that is not accounted for elsewhere in the DMO price.

$$Smart\ Meter\ shortfall = cost\ per\ smart\ meter - \ ACS_{metering\ total} + (ACS_{capital} \times B\%)$$

- We then socialise this shortfall across all customers by multiplying this shortfall by the proportion of all customers with smart meters “S%” to calculate the required allowance in the DMO price.

$$Smart\ Meter\ Allowance = Smart\ Meter\ shortfall\ \times S\%$$

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

Item	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	60,793,551	51,963,952	41,310,271	64,297,990	40,096,277	**258,462,040**
Total advanced meter customers	508,204	463,348	334,459	567,115	359,247	**2,232,373**
Average cost incurred per advanced meter ($) (ex GST)	119.62	112.15	123.51	113.38	111.61	**115.78**
ACS metering allowance included in network component ($) (ex GST)	26.89	N/A		44.23	26.91	**N/A**
Capital metering charge within ACS metering allowance ($)	N/A			30.11	10.77	**N/A**
Proportion of customers that do not incur an ACS charge (new connections with smart meters) (%)	9.5%	N/A				
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-2.55	N/A				
Advanced meter installations where retailer has incurred an ACS capital metering charge (Energex and SA Power Networks) for replacing an accumulation meter (%)	N/A			80.3%	85.1%	**N/A**
Average legacy capital metering charges incurred per advanced meter ($)	N/A			24.16	9.17	**N/A**
Average per advanced meter costs net of ACS metering allowance, including legacy meter capital charges (if applicable) ($)	N/A			93.31	93.87	**N/A**
Total customers	1,500,856	934,406	735,161	1,352,308	785,367	**5,308,098**
Customers with advanced meters (%)	33.86%	49.59%	45.49%	41.94%	45.74%	**42.06%**
Advanced meter cost per customer ($)	37.95	55.61	56.19	39.13	42.94	**N/A**
Additional capital allowance adjustment (see Table B.3) ($)	0.66	0.63	0.97	0.63	0.71	**N/A**

Source: Retailer data request as at 31 March 2024.

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

Item	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	4,465,302	2,633,203	2,912,529	4,282,209	3,228,746	**17,521,989**
Total advanced meter customers	33,549	20,175	23,417	33,279	23,766	**134,186**
Average cost incurred per advanced meter ($) (ex GST)	133.10	130.52	124.38	128.68	135.86	**130.58**
ACS metering allowance included in network component ($) (ex GST)	37.26	N/A		44.23	26.91	**N/A**
Capital metering charge within ACS metering allowance ($)	N/A			30.11	10.77	**N/A**
Proportion of customers that do not incur an ACS charge (new connections with smart meters) (%)	12.3%	N/A				
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-4.58	N/A				
Advanced meter installations where retailer has incurred an ACS capital metering charge (Energex and SA Power Networks) for replacing an accumulation meter (%)	N/A			80.3%	85.1%	**N/A**
Average legacy capital metering charges incurred per advanced meter ($)	N/A			24.16	9.17	**N/A**
Average per advanced meter costs net of ACS metering allowance, including legacy meter capital charges (if applicable) ($)	N/A			108.61	118.12	**N/A**
Total customers	134,652	66,223	74,920	103,209	81,112	**460,116**
Customers with advanced meters (%)	24.92%	30.47%	31.26%	32.24%	29.30%	**29.16%**
Advanced meter cost per customer ($)	28.58	39.76	38.88	35.02	34.61	**N/A**
Additional capital allowance adjustment (see Table B.4) ($)	0.33	0.49	0.65	0.49	0.49	**N/A**

Source: Retailer data request as at 31 March 2024.

Table B.3 Calculation of residential capital allowance adjustment

Item	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 6, based on actual installs at 31 March 2024 ($)	37.95	55.61	56.19	39.13	42.94
Smart meter allowance based on retailer projected installations at 31 December 2024 ($)	44.59	61.92	65.86	45.45	50.01
Projected shortfall in Smart Meter Allowance at 31 December 2024 ($)	6.63	6.30	9.67	6.32	7.07
Weighted average cost of capital applied to shortfall (%)	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (excl. GST) ($)	0.66	0.63	0.97	0.63	0.71

Source: Retailer data request as at 31 March 2024.

Table B.4 Calculation of small business capital allowance adjustment

Item	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 6, based on actual installs at 31 March 2024 ($)	28.58	39.76	38.88	35.02	34.61
Smart meter allowance based on retailer projected installations at 31 December 2024 ($)	31.85	44.68	45.42	39.87	39.51
Projected shortfall in Smart Meter Allowance at 31 December 2024 ($)	3.27	4.92	6.55	4.85	4.90
Weighted average cost of capital applied to shortfall (%)	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (excl. GST) ($)	0.33	0.49	0.65	0.49	0.49

Source: Retailer data request as at 31 March 2024.

C. Legislative instrument

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 23 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 (based on 365 days p.a. in 2024–25)				
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)	**0.2348**	**0.2274**	**0.2161**	**0.1917**	**0.1738**	**0.1578**	**0.1465**	**0.1394**	**0.1364**	**0.1365**	**0.1418**	**0.1506**	**0.1678**	**0.1900**	**0.2037**	**0.2190**	**0.2230**	**0.2228**	**0.2220**	**0.2196**	**0.2168**	**0.2145**	**0.2123**	**0.2120**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2129**	**0.2128**	**0.2116**	**0.2103**	**0.2096**	**0.2102**	**0.2132**	**0.2212**	**0.2330**	**0.2492**	**0.2699**	**0.2956**	**0.3102**	**0.3135**	**0.3077**	**0.3000**	**0.2941**	**0.2874**	**0.2761**	**0.2650**	**0.2596**	**0.2561**	**0.2490**	**0.2403**

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)	**0.2890**	**0.2798**	**0.2659**	**0.2359**	**0.2139**	**0.1942**	**0.1803**	**0.1716**	**0.1679**	**0.1680**	**0.1745**	**0.1853**	**0.2065**	**0.2339**	**0.2508**	**0.2695**	**0.2744**	**0.2743**	**0.2732**	**0.2703**	**0.2669**	**0.2640**	**0.2613**	**0.2610**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2620**	**0.2619**	**0.2604**	**0.2589**	**0.2580**	**0.2588**	**0.2624**	**0.2722**	**0.2867**	**0.3067**	**0.3322**	**0.3638**	**0.3818**	**0.3858**	**0.3787**	**0.3692**	**0.3620**	**0.3538**	**0.3399**	**0.3262**	**0.3195**	**0.3152**	**0.3065**	**0.2958**

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)	**0.3076**	**0.3003**	**0.2731**	**0.2333**	**0.2048**	**0.1843**	**0.1715**	**0.1640**	**0.1624**	**0.1650**	**0.1744**	**0.1870**	**0.2088**	**0.2360**	**0.2477**	**0.2654**	**0.2703**	**0.2685**	**0.2696**	**0.2695**	**0.2682**	**0.2672**	**0.2662**	**0.2679**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2690**	**0.2687**	**0.2670**	**0.2679**	**0.2710**	**0.2751**	**0.2827**	**0.2978**	**0.3155**	**0.3376**	**0.3573**	**0.3854**	**0.3979**	**0.3971**	**0.3872**	**0.3769**	**0.3655**	**0.3529**	**0.3361**	**0.3144**	**0.3138**	**0.3205**	**0.3189**	**0.3148**

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)	**0.3265**	**0.3187**	**0.2898**	**0.2476**	**0.2174**	**0.1956**	**0.1820**	**0.1740**	**0.1724**	**0.1751**	**0.1851**	**0.1985**	**0.2216**	**0.2505**	**0.2629**	**0.2817**	**0.2869**	**0.2849**	**0.2861**	**0.2860**	**0.2846**	**0.2836**	**0.2825**	**0.2843**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2855**	**0.2852**	**0.2833**	**0.2844**	**0.2876**	**0.2920**	**0.3000**	**0.3161**	**0.3348**	**0.3583**	**0.3792**	**0.4090**	**0.4222**	**0.4214**	**0.4109**	**0.4000**	**0.3879**	**0.3745**	**0.3567**	**0.3337**	**0.3330**	**0.3402**	**0.3384**	**0.3341**

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)	**0.1962**	**0.1809**	**0.1710**	**0.1614**	**0.1540**	**0.1491**	**0.1466**	**0.1456**	**0.1481**	**0.1538**	**0.1652**	**0.1808**	**0.2053**	**0.2340**	**0.2573**	**0.2674**	**0.2700**	**0.2681**	**0.2684**	**0.2679**	**0.2661**	**0.2698**	**0.2721**	**0.2759**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2775**	**0.2797**	**0.2802**	**0.2794**	**0.2820**	**0.2834**	**0.2890**	**0.2992**	**0.3111**	**0.3284**	**0.3483**	**0.3734**	**0.3896**	**0.3954**	**0.3839**	**0.3717**	**0.3640**	**0.3444**	**0.3221**	**0.3042**	**0.2884**	**0.2687**	**0.2449**	**0.2187**

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)	**0.1876**	**0.1730**	**0.1636**	**0.1544**	**0.1473**	**0.1426**	**0.1402**	**0.1393**	**0.1416**	**0.1471**	**0.1581**	**0.1730**	**0.1964**	**0.2238**	**0.2461**	**0.2558**	**0.2583**	**0.2565**	**0.2568**	**0.2562**	**0.2545**	**0.2580**	**0.2603**	**0.2639**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2655**	**0.2675**	**0.2680**	**0.2673**	**0.2697**	**0.2711**	**0.2764**	**0.2862**	**0.2976**	**0.3142**	**0.3331**	**0.3571**	**0.3727**	**0.3782**	**0.3672**	**0.3555**	**0.3482**	**0.3295**	**0.3081**	**0.2910**	**0.2758**	**0.2571**	**0.2343**	**0.2092**

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)	**0.2794**	**0.2784**	**0.2681**	**0.2547**	**0.2343**	**0.2102**	**0.1914**	**0.1794**	**0.1740**	**0.1735**	**0.1815**	**0.1948**	**0.2173**	**0.2389**	**0.2485**	**0.2604**	**0.2607**	**0.2536**	**0.2533**	**0.2510**	**0.2486**	**0.2471**	**0.2445**	**0.2418**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2431**	**0.2428**	**0.2406**	**0.2372**	**0.2366**	**0.2375**	**0.2425**	**0.2523**	**0.2646**	**0.2810**	**0.3080**	**0.3422**	**0.3632**	**0.3651**	**0.3541**	**0.3419**	**0.3329**	**0.3217**	**0.3134**	**0.3080**	**0.3119**	**0.3006**	**0.2903**	**0.2861**

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)	**0.2794**	**0.2784**	**0.2681**	**0.2547**	**0.2343**	**0.2102**	**0.1914**	**0.1794**	**0.1740**	**0.1735**	**0.1815**	**0.1948**	**0.2173**	**0.2389**	**0.2485**	**0.2604**	**0.2607**	**0.2536**	**0.2533**	**0.2510**	**0.2486**	**0.2471**	**0.2445**	**0.2418**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2431**	**0.2428**	**0.2406**	**0.2372**	**0.2366**	**0.2375**	**0.2425**	**0.2523**	**0.2646**	**0.2810**	**0.3080**	**0.3422**	**0.3632**	**0.3651**	**0.3541**	**0.3419**	**0.3329**	**0.3217**	**0.3134**	**0.3080**	**0.3119**	**0.3006**	**0.2903**	**0.2861**

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)	**0.2424**	**0.2896**	**0.3014**	**0.2668**	**0.2246**	**0.1934**	**0.1706**	**0.1533**	**0.1427**	**0.1387**	**0.1414**	**0.1495**	**0.1675**	**0.1768**	**0.1999**	**0.2007**	**0.1973**	**0.1932**	**0.1930**	**0.2041**	**0.2167**	**0.2330**	**0.2401**	**0.2384**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2331**	**0.2259**	**0.2195**	**0.2167**	**0.2188**	**0.2192**	**0.2246**	**0.2259**	**0.2406**	**0.2553**	**0.2837**	**0.3127**	**0.3282**	**0.3282**	**0.3184**	**0.3079**	**0.2971**	**0.2854**	**0.2698**	**0.2496**	**0.2260**	**0.2020**	**0.1853**	**0.2100**

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)	**0.2545**	**0.3040**	**0.3165**	**0.2801**	**0.2358**	**0.2031**	**0.1791**	**0.1610**	**0.1498**	**0.1456**	**0.1485**	**0.1570**	**0.1758**	**0.1856**	**0.2099**	**0.2107**	**0.2072**	**0.2028**	**0.2027**	**0.2143**	**0.2275**	**0.2446**	**0.2521**	**0.2503**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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)	**0.2447**	**0.2372**	**0.2305**	**0.2275**	**0.2297**	**0.2301**	**0.2358**	**0.2372**	**0.2526**	**0.2681**	**0.2978**	**0.3284**	**0.3447**	**0.3447**	**0.3344**	**0.3232**	**0.3120**	**0.2997**	**0.2833**	**0.2620**	**0.2373**	**0.2121**	**0.1946**	**0.2205**

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**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.2466**	**0.2466**	**0.2466**	**0.2466**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 13.30	13:30 - 14:00	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 - 19:00	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**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**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)[163]

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

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

7. Per-customer annual price determination

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

Per-customer annual price determination (all prices GST-inclusive)			
Distribution region	**Annual Residential Price without Controlled Load**	**Annual Residential Price with Controlled Load**	**Small Business Annual Price**
Ausgrid	$1,810	$2,495	$4,597
Endeavour Energy	$2,209	$2,787	$4,407
Energex	$2,052	$2,400	$4,246
Essential Energy	$2,499	$2,918	$5,718
SA Power Networks	$2,216	$2,746	$5,337

DATED THIS 23 DAY OF
MAY 2024

Australian Energy Regulator

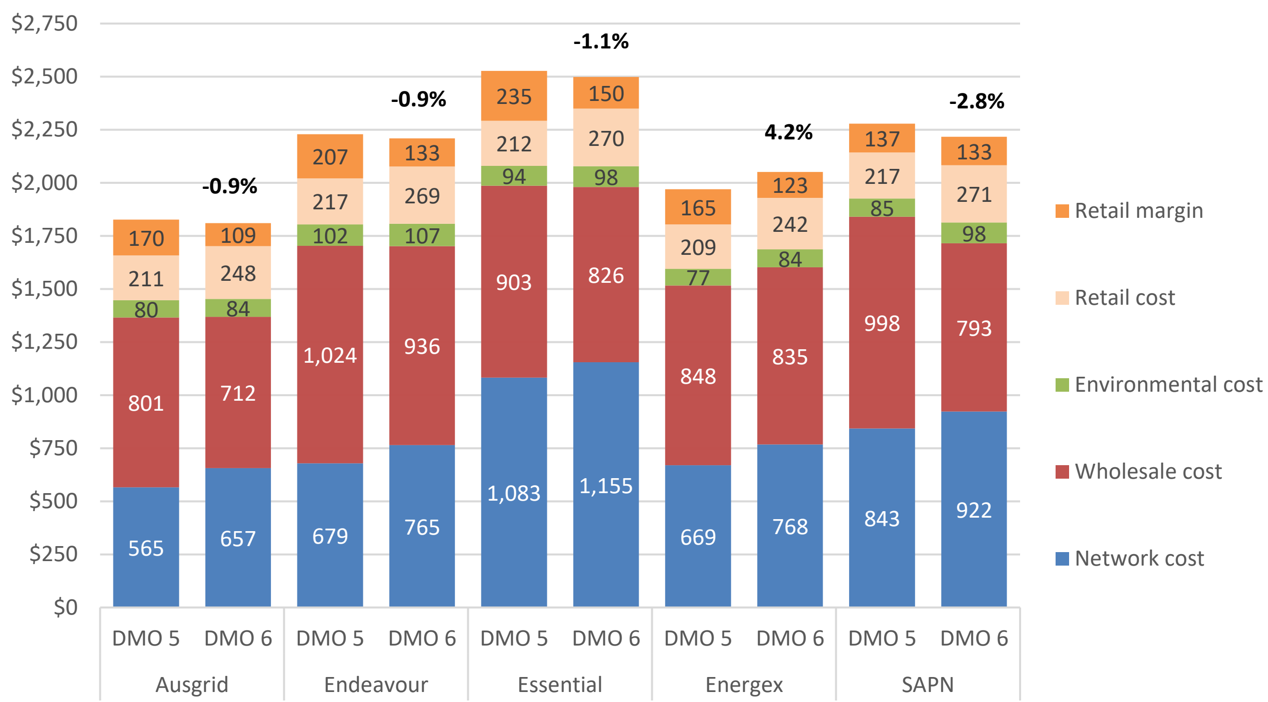
D. DMO 5 to DMO 6 price movements

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 distribution region.

We note that:

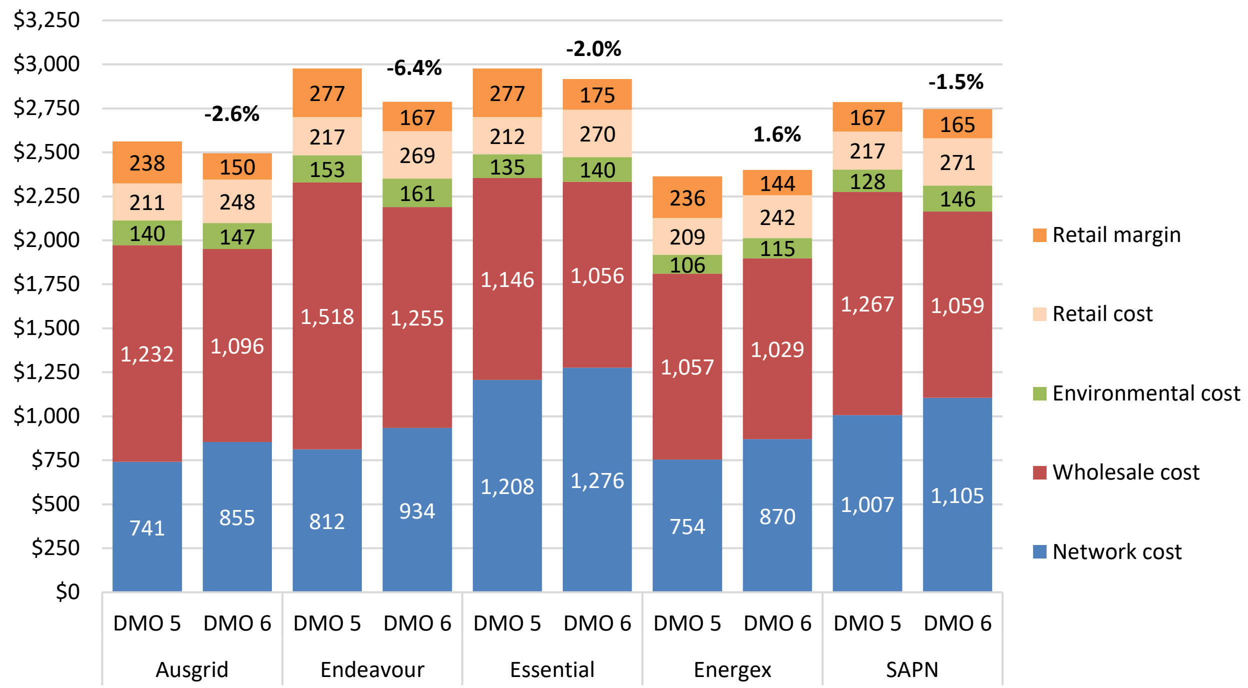
- Network, retail and environment cost components in DMO 6 are calculated using predominately the same methodology as DMO 5, so the changes directly reflect year-on-year movement. Network costs include NSW Roadmap costs in NSW and environmental costs include known applicable environmental schemes.
- 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, as well as, in Energex and SA Power Networks, adopting the midpoint of the 2 WECs resulting from the different NSLPs.

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



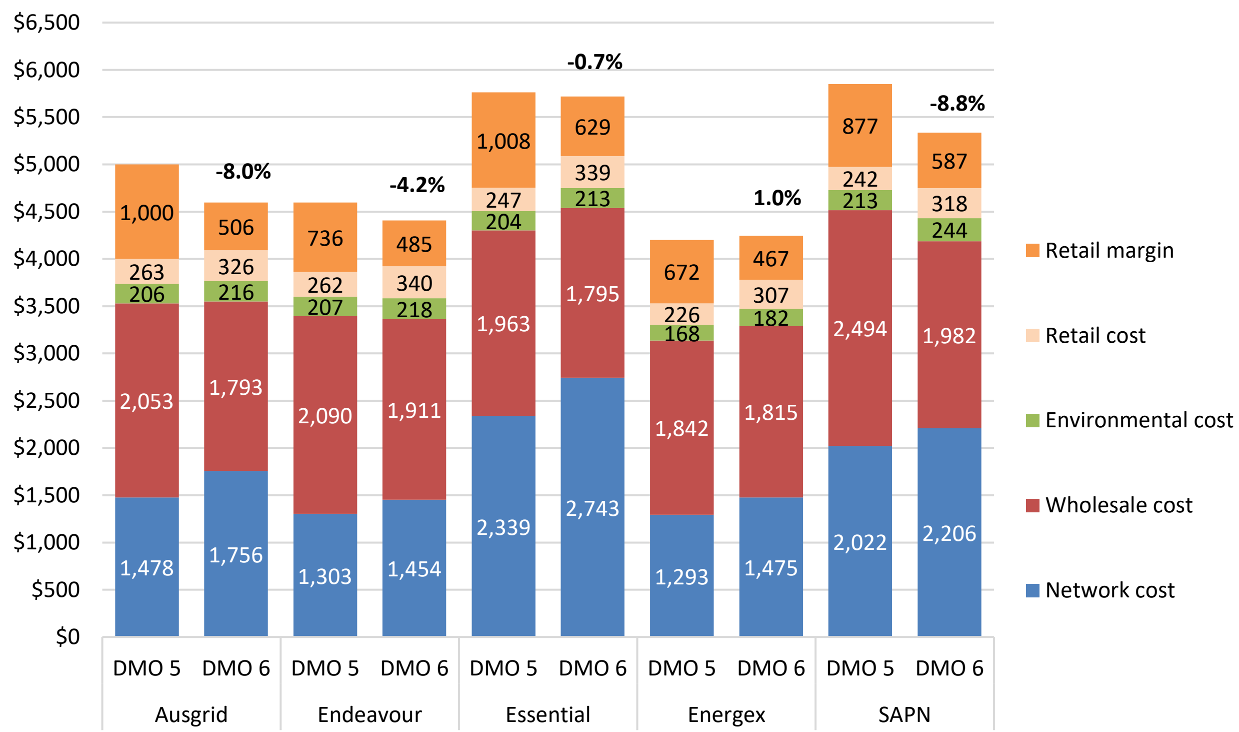
Source: AER Default market offer 2024–25 cost assessment model.

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



Source: AER Default market offer 2024–25 cost assessment model.

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



Source: AER Default market offer 2024–25 cost assessment model.

E. State-based summaries of cost changes

This appendix explains in further detail the DMO cost stack changes from DMO 5 to DMO 6 for each state.

NSW summary

NSW **residential customers without controlled load** will see price decreases of $17 or 0.9% (Ausgrid), $19 or 0.9% (Endeavour Energy) and $28 or 1.1% (Essential Energy). This is around 5% below forecast inflation. **Residential customers with controlled load** will see price decreases of $67 or 2.6% (Ausgrid), $190 or 6.4% (Endeavour Energy) and $59 or 2% (Essential Energy). These are decreases of between 6% and 10% below forecast inflation. **Small business customers** will see decreases of $402 or 8% (Ausgrid), $191 or 4.2% (Endeavour Energy) and $43 or 0.7% (Essential Energy). These are decreases of between 4% and 12% below forecast inflation.

As outlined more specifically in the tables below, since the DMO 5 final determination we have observed the following:

- Across each region of NSW there have been decreases in wholesale costs for all customer types.
  - This has been driven by movements in contract prices, as well as the shape of load profiles used. Specific contract price movements for 2024–25 on an annualised and trade weighted basis were a decrease in base futures contract prices of $11.65/MWh and a decrease in cap contract prices of $1.28/MWh. Our inclusion of interval meter data also caused the resulting load shapes to change from DMO 5.
- Across each region of NSW network costs have risen. This rise is seen in all customer types.
  - In 2024 the 3 NSW distribution networks had their revenue determinations made for the 2024–29 regulatory period. Revenue determinations involve an extensive regulatory process in which we confirm how much an electricity distribution business can recover from consumers over a 5-year period. Every year, electricity distribution businesses are required to submit a pricing proposal that contains the network tariffs they propose to charge their customers to recover their revenues, transmission network charges and the costs of jurisdictional schemes.
  - The AER undertakes a compliance check of the proposals against the National Energy Rules and each distributor's 5-year regulatory revenue determination.
  - This year the increases in network costs are due to a combination of updated fixed and variable tariffs as well as updated legacy metering costs. Increases are driven by increasing transmission costs, inflation costs and includes a significant increase (from $138.14 million to $341.25 million) in the recovery of NSW Roadmap costs for 2024–25 across all 3 NSW networks. In Ausgrid there has been an

increase in incentive scheme payments, while in Endeavour Energy and Essential Energy networks increases have been partially offset by adjustments to return over-recovered allowed distribution revenues from previous years.

- Environmental costs have risen across each region of NSW and all customer types. These increases are mainly driven by increases in both federal and state renewable energy target schemes.
- Retail costs have risen for all customers in each region of NSW. For residential customers this was primarily due to rising smart meter costs stemming from the growth in installations, and increases in bad and doubtful debt costs. For small business customers, there was also a general uplift in operating costs.
- DMO retail allowance/margin has reduced in DMO 6 due to a change in methodology and a consistently lower allowance and margin being applied. The retail margin moved down to 6% from 9.3% for residential customers, and for small business down to 11% from 20% in Ausgrid, down to 11% from 16% in Endeavour Energy, and down to 11% from 17.5% in Essential Energy). This also meant the overall dollar margin decreased by as much as 36.2% for **residential customers without controlled load,** 39.6% for **residential customers with controlled load** and 49.4% for **small business customers**, depending on the region.

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Residential without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)													
Ausgrid	Network cost	565.43		636.98		656.75		71.55	12.7%	19.77	3.1%	91.33	16.2%
	Wholesale cost	800.57		714.41		712.34		-86.15	-10.8%	-2.07	-0.3%	-88.22	-11.0%
	Environmental cost	80.36		83.12		84.26		2.76	3.4%	1.14	1.4%	3.89	4.8%
	Retail cost	210.91		232.51		248.17		21.61	10.2%	15.66	6.7%	37.26	17.7%
	Retail margin	169.93	*9.3%*	106.41	*6.0%*	108.61	*6.0%*	-63.52	-37.4%	2.20	2.1%	-61.32	-36.1%
	Total	**1,827**		**1,773**		**1,810**		**-54**	**-2.9%**	**37**	2.1%	**-17**	**-0.9%**
Endeavour Energy	Network cost	678.73		745.72		764.81		66.99	9.9%	19.09	2.6%	86.08	12.7%
	Wholesale cost	1,024.11		958.77		936.27		-65.34	-6.4%	-22.51	-2.3%	-87.85	-8.6%
	Environmental cost	101.60		105.37		106.78		3.77	3.7%	1.40	1.3%	5.18	5.1%
	Retail cost	216.54		243.99		268.94		27.45	12.7%	24.95	10.2%	52.40	24.2%
	Retail margin	207.22	*9.3%*	131.10	*6.0%*	132.56	*6.0%*	-76.13	-36.7%	1.46	1.1%	-74.66	-36.0%
	Total	**2,228**		**2,185**		**2,209**		**-43**	-1.9%	**24**	1.1%	**-19**	**-0.9%**
Essential Energy	Network cost	1,082.80		1,220.05		1,155.09		137.25	12.7%	-64.96	-5.3%	72.29	6.7%
	Wholesale cost	903.23		837.33		825.71		-65.90	-7.3%	-11.62	-1.4%	-77.51	-8.6%

	Environmental cost	93.77		96.49		97.86		2.72	2.9%	1.37	1.4%	4.09	4.4%
	Retail cost	211.99		241.80		270.03		29.82	14.1%	28.23	11.7%	58.04	27.4%
	Retail margin	234.99	*9.3%*	152.92	*6.0%*	149.92	*6.0%*	-82.07	-34.9%	-3.00	-2.0%	-85.07	-36.2%
	Total	**2,527**		**2,549**		**2,499**		**22**	0.9%	**-50**	-2.0%	**-28**	**-1.1%**

Residential with CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Ausgrid	Network cost	740.73		834.24		854.76		93.51	12.6%	20.51	2.5%	114.02	15.4%
	Wholesale cost	1,232.03		1,115.55		1,095.58		-116.48	-9.5%	-19.97	-1.8%	-136.45	-11.1%
	Environmental cost	140.18		145.07		147.15		4.89	3.5%	2.08	1.4%	6.97	5.0%
	Retail cost	210.91		232.51		248.17		21.61	10.2%	15.66	6.7%	37.26	17.7%
	Retail margin	238.28	*9.3%*	148.56	*6.0%*	149.72	*6.0%*	-89.72	-37.7%	1.17	0.8%	-88.55	-37.2%
	Total	**2,562**		**2,476**		**2,495**		**-86**	-3.4%	**19**	0.8%	**-67**	**-2.6%**
Endeavour Energy	Network cost	811.77		914.53		934.14		102.76	12.7%	19.61	2.1%	122.37	15.1%
	Wholesale cost	1,518.32		1,282.63		1,255.44		-235.68	-15.5%	-27.19	-2.1%	-262.87	-17.3%
	Environmental cost	153.45		159.14		161.25		5.69	3.7%	2.12	1.3%	7.80	5.1%
	Retail cost	216.54		243.99		268.94		27.45	12.7%	24.95	10.2%	52.40	24.2%
	Retail margin	276.86	*9.3%*	165.98	*6.0%*	167.22	*6.0%*	-110.88	-40.0%	1.24	0.7%	-109.64	-39.6%
	Total	**2,977**		**2,766**		**2,787**		**-211**	-7.1%	**21**	0.7%	**-190**	**-6.4%**
Essential Energy	Network cost	1,207.88		1,338.42		1,276.37		130.54	10.8%	-62.05	-4.6%	68.49	5.7%
	Wholesale cost	1,146.06		1,067.25		1,055.66		-78.81	-6.9%	-11.59	-1.1%	-90.40	-7.9%
	Environmental cost	134.53		138.45		140.41		3.92	2.9%	1.96	1.4%	5.88	4.4%
	Retail cost	211.99		241.80		270.03		29.82	14.1%	28.23	11.7%	58.04	27.4%
	Retail margin	276.89	*9.3%*	177.82	*6.0%*	175.05	*6.0%*	-99.07	-35.8%	-2.77	-1.6%	-101.84	-36.8%
	Total	**2,977**		**2,964**		**2,918**		**-14**	-0.5%	**-46**	-1.6%	**-59**	**-2.0%**

Small business without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Ausgrid	Network cost	1,477.61		1,652.11		1,756.19		174.50	11.8%	104.08	6.3%	278.58	18.9%
	Wholesale cost	2,052.52		1,831.83		1,792.93		-220.69	-10.8%	-38.90	-2.1%	-259.58	-12.6%
	Environmental cost	206.03		213.18		216.04		7.15	3.5%	2.86	1.3%	10.01	4.9%
	Retail cost	262.69		318.51		326.29		55.83	21.3%	7.78	2.4%	63.60	24.2%
	Retail margin	999.71	*20.0%*	496.31	*11.0%*	505.69	*11.0%*	-503.40	-50.4%	9.37	1.9%	-494.03	-49.4%
	Total	**4,999**		**4,512**		**4,597**		**-487**	-9.7%	**85**	1.9%	**-402**	**-8.0%**
Endeavour Energy	Network cost	1,302.75		1,420.05		1,453.95		117.30	9.0%	33.90	2.4%	151.20	11.6%
	Wholesale cost	2,090.13		1,956.68		1,910.74		-133.45	-6.4%	-45.94	-2.3%	-179.38	-8.6%
	Environmental cost	207.36		215.05		217.91		7.69	3.7%	2.86	1.3%	10.55	5.1%
	Retail cost	261.94		318.89		339.66		56.95	21.7%	20.77	6.5%	77.72	29.7%
	Retail margin	735.65	*16.0%*	483.34	*11.0%*	484.77	*11.0%*	-252.31	-34.3%	1.43	0.3%	-250.88	-34.1%
	Total	**4,598**		**4,394**		**4,407**		**-204**	-4.4%	**13**	0.3%	**-191**	**-4.2%**
Essential Energy	Network cost	2,339.26		2,813.83		2,742.78		474.57	20.3%	-71.05	-2.5%	403.53	17.3%
	Wholesale cost	1,963.29		1,820.28		1,795.02		-143.01	-7.3%	-25.26	-1.4%	-168.26	-8.6%
	Environmental cost	203.83		209.77		212.74		5.94	2.9%	2.97	1.4%	8.91	4.4%
	Retail cost	246.52		319.84		338.81		73.32	29.7%	18.97	5.9%	92.29	37.4%
	Retail margin	1,008.19	*17.5%*	638.21	*11.0%*	629.02	*11.0%*	-369.98	-36.7%	-9.19	-1.4%	-379.17	-37.6%
	Total	**5,761**		**5,802**		**5,718**		**41**	0.7%	**-84**	-1.4%	**-43**	**-0.7%**

Source: AER Default market offer 2024–25 cost assessment model.

SE Queensland summary

SE Queensland **customers without controlled load** face an overall price increase of $83 or 4.2% (in line with forecast inflation). **Customers with controlled load** will face an increase of $37 or 1.6% (which is a decrease of 2% below forecast inflation). **Small business customers** can expect an increase of $44 or 1% (a 3% decrease below forecast inflation).

As outlined more specifically in the tables below, since the DMO 5 final determination we have observed the following in SE Queensland:

- A minor decrease in wholesale costs across all customer types. This has been driven by movements in contract prices and the shape of the load profiles used for the wholesale modelling:
  - Specific contract price movements for 2024–25 on an annualised and trade weighted basis were a decrease in base futures contract prices of $2.71/MWh and an increase in cap contract prices of $0.11/MWh. Compared with other times across the year, the Queensland region increasingly relies on cap contracts during the peak demand period of summer. Wholesale costs in SE Queensland did not decrease as much as other regions due to increased trading prices of these summer cap contracts.
- Network costs have increased across all customer types. This is due to network tariff increases which are driven by higher inflation, increases in incentive scheme payments, and increases in transmission costs. The network costs were also impacted by recovery of previous under-recoveries in jurisdictional scheme costs; offset by the return of previous over-recoveries of allowed distribution revenues.
- Environmental costs have increased across all customers. This is mainly driven by increases in both federal and state renewable energy target schemes.
- Retail costs have increased across all customers by between 15.8% and 35.8%. This has been primarily due to increases in operating costs, smart meter costs and increases in bad and doubtful debt costs.
- Retail allowance decreases have been due to changes in the AER's methodology, and a consistently lower allowance and margin being applied (8.4% to 6% for residential customers, 10% to 6% for residential customers with controlled load and 16% to 11% for small business customers). This also meant the overall dollar margin decreased by between 25.6% and 39.1% depending on the customer type.

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Residential without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)													
Energex	Network cost	669.42		746.55		767.81		77.13	11.5%	21.26	2.8%	98.39	14.7%
	Wholesale cost	847.56		838.95		834.77		-8.61	-1.0%	-4.18	-0.5%	-12.79	-1.5%
	Environmental cost	77.43		80.35		83.64		2.92	3.8%	3.29	4.1%	6.21	8.0%
	Retail cost	209.30		234.46		242.45		25.16	12.0%	8.00	3.4%	33.16	15.8%
	Retail margin	165.41	*8.4%*	121.30	*6.0%*	123.11	*6.0%*	-44.11	-26.7%	1.81	1.5%	-42.30	-25.6%
	Total	**1,969**		**2,022**		**2,052**		**52**	2.7%	**30**	1.5%	**83**	**4.2%**
Residential with CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)													
Energex	Network cost	754.36		843.60		870.29		89.24	11.8%	26.69	3.2%	115.93	15.4%
	Wholesale cost	1,057.28		1,032.85		1,028.71		-24.43	-2.3%	-4.14	-0.4%	-28.58	-2.7%
	Environmental cost	106.04		110.05		114.55		4.01	3.8%	4.50	4.1%	8.51	8.0%
	Retail cost	209.30		234.46		242.45		25.16	12.0%	8.00	3.4%	33.16	15.8%
	Retail margin	236.33	*10.0%*	141.76	*6.0%*	144.00	*6.0%*	-94.57	-40.0%	2.24	1.6%	-92.33	-39.1%
	Total	**2,363**		**2,363**		**2,400**		**-1**	-0.0%	**37**	1.6%	**37**	**1.6%**
Small business without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)													
Energex	Network cost	1,293.07		1,431.02		1,475.39		137.95	10.7%	44.37	3.1%	182.32	14.1%
	Wholesale cost	1,842.29		1,823.80		1,814.71		-18.49	-1.0%	-9.09	-0.5%	-27.58	-1.5%
	Environmental cost	168.31		174.68		181.83		6.37	3.8%	7.15	4.1%	13.52	8.0%
	Retail cost	226.03		300.22		306.97		74.18	32.8%	6.75	2.2%	80.94	35.8%
	Retail margin	672.33	*16.0%*	460.98	*11.0%*	467.06	*11.0%*	-211.35	-31.4%	6.08	1.3%	-205.27	-30.5%
	Total	**4,202**		**4,191**		**4,246**		**-11**	-0.3%	**55**	1.3%	**44**	**1.0%**

Source: AER Default market offer 2024–25 cost assessment model.

South Australia summary

South Australian **residential customers without controlled load** will experience a price fall of $63 or 2.8% (7% below forecast inflation). Residential **customers with controlled load** face decreases $41 or 1.5% (a 5% decrease below forecast inflation). **Small business customers** will see a decrease of $512 or 8.8% (13% below forecast inflation).

As outlined more specifically in the tables below, since the DMO 5 final determination we have observed the following in South Australia:

- Wholesale cost decreases across all customer types. This has been driven by movements in contract prices and the shape of the load profiles used for wholesale modelling:
  - Specific contract price movements for 2024–25 on an annualised and trade weighted basis were a decrease in base futures contract prices of $2.27/MWh and a decrease in cap contract prices of $0.74/MWh. The lower wholesale costs were primarily driven by a large decrease in cap contract prices during the peak demand period of summer in South Australia.
  - The load profile used to model wholesale costs in South Australia has flattened and changed the most since DMO 5 (compared to the other regions).
- Network costs have increased across all customer types. Increases are primarily driven by recovery of previous under-recoveries of allowed distribution revenue, inflation and a cost pass-through for the River Murray flood event. These increases are partially offset by decreases in incentive scheme payments and jurisdictional scheme costs, as well as the AER’s decision to return previously over-recovered distribution revenue to customers.
- Environmental cost increases across all customers. These increases have been the largest observed across all jurisdictions in the last 12-month period (14.3% increase). This is mainly driven by increases in both federal and state renewable energy target schemes, and the South Australian Retailer Energy Productivity Scheme, which increased by 43%.
- Retail cost increases across all customers. The year-on-year increase of 25% to 31% is primarily due to operating costs, increases in bad and doubtful debt costs and increase in smart meter costs.
- DMO allowance decreases were due to a change in methodology, a consistently lower allowance being applied to both customer types, and a consistently lower margin being applied to small business (down to 11% from 15%). There was no change in the margin for residential customers as the DMO allowance in South Australia was already at 6%. This also meant the overall dollar margin decreased by between 1.5% and 33.1% depending on the customer type, as this is a proportion of other costs which have declined.

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Residential without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)													
SA Power Networks	**Network cost**	**842.78**		**924.98**		**922.34**		**82.21**	**9.8%**	**-2.64**	**-0.3%**	**79.57**	**9.4%**
	Wholesale cost	997.71		809.47		792.68		-188.24	-18.9%	-16.79	-2.1%	-205.03	-20.6%
	Environmental cost	85.29		94.29		97.50		9.01	10.6%	3.21	3.4%	12.22	14.3%
	Retail cost	216.56		260.28		270.61		43.72	20.2%	10.33	4.0%	54.04	25.0%
	Retail margin	136.74	*6.0%*	133.34	*6.0%*	132.97	*6.0%*	-3.40	-2.5%	-0.38	-0.3%	-3.78	-2.8%
	Total	**2,279**		**2,222**		**2,216**		**-57**	-2.5%	**-6**	-0.3%	**-63**	**-2.8%**
Residential with CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)													
SA Power Networks	Network cost	**1,007.22**		**1,111.65**		**1,105.12**		**104.43**	**10.4%**	**-6.53**	**-0.6%**	**97.90**	**9.7%**
	Wholesale cost	1,267.34		1,093.58		1,058.95		-173.76	-13.7%	-34.63	-3.2%	-208.39	-16.4%
	Environmental cost	127.92		141.44		146.26		13.52	10.6%	4.82	3.4%	18.34	14.3%
	Retail cost	216.56		260.28		270.61		43.72	20.2%	10.33	4.0%	54.04	25.0%
	Retail margin	167.17	*6.0%*	166.40	*6.0%*	164.74	*6.0%*	-0.77	-0.5%	-1.66	-1.0%	-2.43	-1.5%
	Total	**2,787**		**2,773**	**6.0%**	**2,746**		**-13**	-0.5%	**-28**	-1.0%	**-41**	**-1.5%**
Small business without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)													
SA Power Networks	Network cost	2,021.89		2,208.65		2,206.45		186.76	9.2%	-2.20	-0.1%	184.56	9.1%
	Wholesale cost	2,494.15		2,023.67		1,981.69		-470.48	-18.9%	-41.98	-2.1%	-512.45	-20.5%
	Environmental cost	213.20		235.73		243.76		22.53	10.6%	8.03	3.4%	30.56	14.3%
	Retail cost	242.41		309.35		318.27		66.94	27.6%	8.92	2.9%	75.86	31.3%
	Retail margin	877.35	*15.0%*	590.47	*11.0%*	587.10	*11.0%*	-286.88	-32.7%	-3.37	-0.6%	-290.25	-33.1%
	Total	**5,849**		**5,368**		**5,337**		**-481**	-8.2%	**-31**	-0.6%	**-512**	**-8.8%**

Source: AER Default market offer 2024–25 cost assessment model.

F. Summary of cost stack component price movements

Table 1: Residential without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Ausgrid	Network cost	565.43		636.98		656.75		71.55	12.7%	19.77	3.1%	91.33	16.2%
	Wholesale cost	800.57		714.41		712.34		-86.15	-10.8%	-2.07	-0.3%	-88.22	-11.0%
	Environmental cost	80.36		83.12		84.26		2.76	3.4%	1.14	1.4%	3.89	4.8%
	Retail cost	210.91		232.51		248.17		21.61	10.2%	15.66	6.7%	37.26	17.7%
	Retail margin	169.93	*9.3%*	106.41	*6.0%*	108.61	*6.0%*	-63.52	-37.4%	2.20	2.1%	-61.32	-36.1%
	Total	**1,827**		**1,773**		**1,810**		**-54**	**-2.9%**	**37**	2.1%	**-17**	**-0.9%**
Endeavour Energy	Network cost	678.73		745.72		764.81		66.99	9.9%	19.09	2.6%	86.08	12.7%
	Wholesale cost	1,024.11		958.77		936.27		-65.34	-6.4%	-22.51	-2.3%	-87.85	-8.6%
	Environmental cost	101.60		105.37		106.78		3.77	3.7%	1.40	1.3%	5.18	5.1%
	Retail cost	216.54		243.99		268.94		27.45	12.7%	24.95	10.2%	52.40	24.2%
	Retail margin	207.22	*9.3%*	131.10	*6.0%*	132.56	*6.0%*	-76.13	-36.7%	1.46	1.1%	-74.66	-36.0%
	Total	**2,228**		**2,185**		**2,209**		**-43**	-1.9%	**24**	1.1%	**-19**	**-0.9%**
Essential Energy	Network cost	1,082.80		1,220.05		1,155.09		137.25	12.7%	-64.96	-5.3%	72.29	6.7%
	Wholesale cost	903.23		837.33		825.71		-65.90	-7.3%	-11.62	-1.4%	-77.51	-8.6%
	Environmental cost	93.77		96.49		97.86		2.72	2.9%	1.37	1.4%	4.09	4.4%
	Retail cost	211.99		241.80		270.03		29.82	14.1%	28.23	11.7%	58.04	27.4%
	Retail margin	234.99	*9.3%*	152.92	*6.0%*	149.92	*6.0%*	-82.07	-34.9%	-3.00	-2.0%	-85.07	-36.2%
	Total	**2,527**		**2,549**		**2,499**		**22**	0.9%	**-50**	-2.0%	**-28**	**-1.1%**
Energex	Network cost	669.42		746.55		767.81		77.13	11.5%	21.26	2.8%	98.39	14.7%
	Wholesale cost	847.56		838.95		834.77		-8.61	-1.0%	-4.18	-0.5%	-12.79	-1.5%
	Environmental cost	77.43		80.35		83.64		2.92	3.8%	3.29	4.1%	6.21	8.0%
	Retail cost	209.30		234.46		242.45		25.16	12.0%	8.00	3.4%	33.16	15.8%
	Retail margin	165.41	*8.4%*	121.30	*6.0%*	123.11	*6.0%*	-44.11	-26.7%	1.81	1.5%	-42.30	-25.6%
	Total	**1,969**		**2,022**		**2,052**		**52**	2.7%	**30**	1.5%	**83**	**4.2%**
SA Power Networks	Network cost	842.78		924.98		922.34		82.21	9.8%	-2.64	-0.3%	79.57	9.4%
	Wholesale cost	997.71		809.47		792.68		-188.24	-18.9%	-16.79	-2.1%	-205.03	-20.6%
	Environmental cost	85.29		94.29		97.50		9.01	10.6%	3.21	3.4%	12.22	14.3%
	Retail cost	216.56		260.28		270.61		43.72	20.2%	10.33	4.0%	54.04	25.0%
	Retail margin	136.74	*6.0%*	133.34	*6.0%*	132.97	*6.0%*	-3.40	-2.5%	-0.38	-0.3%	-3.78	-2.8%

	Total	**2,279**		**2,222**		**2,216**		-57	-2.5%	-6	-0.3%	-63	**-2.8%**

Source: AER Default market offer 2024–25 cost assessment model.

Table 2: Residential with CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Ausgrid	Network cost	740.73		834.24		854.76		93.51	12.6%	20.51	2.5%	114.02	15.4%
	Wholesale cost	1,232.03		1,115.55		1,095.58		-116.48	-9.5%	-19.97	-1.8%	-136.45	-11.1%
	Environmental cost	140.18		145.07		147.15		4.89	3.5%	2.08	1.4%	6.97	5.0%
	Retail cost	210.91		232.51		248.17		21.61	10.2%	15.66	6.7%	37.26	17.7%
	Retail margin	238.28	*9.3%*	148.56	*6.0%*	149.72	*6.0%*	-89.72	-37.7%	1.17	0.8%	-88.55	-37.2%
	Total	**2,562**		**2,476**		**2,495**		**-86**	-3.4%	**19**	0.8%	**-67**	**-2.6%**
Endeavour Energy	Network cost	811.77		914.53		934.14		102.76	12.7%	19.61	2.1%	122.37	15.1%
	Wholesale cost	1,518.32		1,282.63		1,255.44		-235.68	-15.5%	-27.19	-2.1%	-262.87	-17.3%
	Environmental cost	153.45		159.14		161.25		5.69	3.7%	2.12	1.3%	7.80	5.1%
	Retail cost	216.54		243.99		268.94		27.45	12.7%	24.95	10.2%	52.40	24.2%
	Retail margin	276.86	*9.3%*	165.98	*6.0%*	167.22	*6.0%*	-110.88	-40.0%	1.24	0.7%	-109.64	-39.6%
	Total	**2,977**		**2,766**		**2,787**		**-211**	-7.1%	**21**	0.7%	**-190**	**-6.5%**
Essential Energy	Network cost	1,207.88		1,338.42		1,276.37		130.54	10.8%	-62.05	-4.6%	68.49	5.7%
	Wholesale cost	1,146.06		1,067.25		1,055.66		-78.81	-6.9%	-11.59	-1.1%	-90.40	-7.9%
	Environmental cost	134.53		138.45		140.41		3.92	2.9%	1.96	1.4%	5.88	4.4%
	Retail cost	211.99		241.80		270.03		29.82	14.1%	28.23	11.7%	58.04	27.4%
	Retail margin	276.89	*9.3%*	177.82	*6.0%*	175.05	*6.0%*	-99.07	-35.8%	-2.77	-1.6%	-101.84	-36.8%
	Total	**2,977**		**2,964**		**2,918**		**-14**	-0.5%	**-46**	-1.6%	**-59**	**-2.0%**
Energex	Network cost	754.36		843.60		870.29		89.24	11.8%	26.69	3.2%	115.93	15.4%
	Wholesale cost	1,057.28		1,032.85		1,028.71		-24.43	-2.3%	-4.14	-0.4%	-28.58	-2.7%
	Environmental cost	106.04		110.05		114.55		4.01	3.8%	4.50	4.1%	8.51	8.0%
	Retail cost	209.30		234.46		242.45		25.16	12.0%	8.00	3.4%	33.16	15.8%
	Retail margin	236.33	*10.0%*	141.76	*6.0%*	144.00	*6.0%*	-94.57	-40.0%	2.24	1.6%	-92.33	-39.1%
	Total	**2,363**		**2,363**		**2,400**		**-1**	-0.0%	**37**	1.6%	**37**	**1.6%**
SA Power Networks	Network cost	1,007.22		1,111.65		1,105.12		104.43	10.4%	-6.53	-0.6%	97.90	9.7%
	Wholesale cost	1,267.34		1,093.58		1,058.95		-173.76	-13.7%	-34.63	-3.2%	-208.39	-16.4%
	Environmental cost	127.92		141.44		146.26		13.52	10.6%	4.82	3.4%	18.34	14.3%

	Retail cost	216.56		260.28		270.61		43.72	20.2%	10.33	4.0%	54.04	25.0%
	Retail margin	167.17	6.0%	166.40	6.0%	164.74	6.0%	-0.77	-0.5%	-1.66	-1.0%	-2.43	-1.5%
	Total	**2,787**		**2,773**	**6.0%**	**2,746**		-13	-0.5%	-28	-1.0%	-41	**-1.5%**

Source: AER Default market offer 2024–25 cost assessment model.

Table 3: Small business without CL, change from final determination DMO 5 to draft determination DMO 6 and final determination DMO 6 (nominal)

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Final determination DMO 6		Difference from DMO 5 to Draft DMO 6		Difference from DMO 6 Draft to Final		Difference from year-on-year	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*	*$ diff*	*% diff*	*$ diff*	*% diff*
Ausgrid	Network cost	1,477.61		1,652.11		1,756.19		174.50	11.8%	104.08	6.3%	278.58	18.9%
	Wholesale cost	2,052.52		1,831.83		1,792.93		-220.69	-10.8%	-38.90	-2.1%	-259.58	-12.6%
	Environmental cost	206.03		213.18		216.04		7.15	3.5%	2.86	1.3%	10.01	4.9%
	Retail cost	262.69		318.51		326.29		55.83	21.3%	7.78	2.4%	63.60	24.2%
	Retail margin	999.71	*20.0%*	496.31	*11.0%*	505.69	*11.0%*	-503.40	-50.4%	9.37	1.9%	-494.03	-49.4%
	Total	**4,999**		**4,512**		**4,597**		**-487**	-9.7%	**85**	1.9%	**-402**	**-8.0%**
Endeavour Energy	Network cost	1,302.75		1,420.05		1,453.95		117.30	9.0%	33.90	2.4%	151.20	11.6%
	Wholesale cost	2,090.13		1,956.68		1,910.74		-133.45	-6.4%	-45.94	-2.3%	-179.38	-8.6%
	Environmental cost	207.36		215.05		217.91		7.69	3.7%	2.86	1.3%	10.55	5.1%
	Retail cost	261.94		318.89		339.66		56.95	21.7%	20.77	6.5%	77.72	29.7%
	Retail margin	735.65	*16.0%*	483.34	*11.0%*	484.77	*11.0%*	-252.31	-34.3%	1.43	0.3%	-250.88	-34.1%
	Total	**4,598**		**4,394**		**4,407**		**-204**	-4.4%	**13**	0.3%	**-191**	**-4.2%**
Essential Energy	Network cost	2,339.26		2,813.83		2,742.78		474.57	20.3%	-71.05	-2.5%	403.53	17.3%
	Wholesale cost	1,963.29		1,820.28		1,795.02		-143.01	-7.3%	-25.26	-1.4%	-168.26	-8.6%
	Environmental cost	203.83		209.77		212.74		5.94	2.9%	2.97	1.4%	8.91	4.4%
	Retail cost	246.52		319.84		338.81		73.32	29.7%	18.97	5.9%	92.29	37.4%
	Retail margin	1,008.19	*17.5%*	638.21	*11.0%*	629.02	*11.0%*	-369.98	-36.7%	-9.19	-1.4%	-379.17	-37.6%
	Total	**5,761**		**5,802**		**5,718**		**41**	0.7%	**-84**	-1.4%	**-43**	**-0.7%**
Energex	Network cost	1,293.07		1,431.02		1,475.39		137.95	10.7%	44.37	3.1%	182.32	14.1%
	Wholesale cost	1,842.29		1,823.80		1,814.71		-18.49	-1.0%	-9.09	-0.5%	-27.58	-1.5%
	Environmental cost	168.31		174.68		181.83		6.37	3.8%	7.15	4.1%	13.52	8.0%
	Retail cost	226.03		300.22		306.97		74.18	32.8%	6.75	2.2%	80.94	35.8%
	Retail margin	672.33	*16.0%*	460.98	*11.0%*	467.06	*11.0%*	-211.35	-31.4%	6.08	1.3%	-205.27	-30.5%
	Total	**4,202**		**4,191**		**4,246**		**-11**	-0.3%	**55**	1.3%	**44**	**1.0%**
SA Power Networks	Network cost	2,021.89		2,208.65		2,206.45		186.76	9.2%	-2.20	-0.1%	184.56	9.1%
	Wholesale cost	2,494.15		2,023.67		1,981.69		-470.48	-18.9%	-41.98	-2.1%	-512.45	-20.5%

	Environmental cost	213.20		235.73		243.76		22.53	10.6%	8.03	3.4%	30.56	14.3%
	Retail cost	242.41		309.35		318.27		66.94	27.6%	8.92	2.9%	75.86	31.3%
	Retail margin	877.35	*15.0%*	590.47	*11.0%*	587.10	*11.0%*	-286.88	-32.7%	-3.37	-0.6%	-290.25	-33.1%
	Total	**5,849**		**5,368**		**5,337**		**-481**	-8.2%	**-31**	-0.6%	**-512**	**-8.8%**

Source: AER Default market offer 2024–25 cost assessment model.