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Default market offer prices

Final determination

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Glossary

Term	Definition
ACS	Alternative control services
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACOSS	Australian Council of Social Service
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CER	Clean Energy Regulator
CPI	Consumer Price Index
CL	Controlled load
DMO	Default market offer
DMO 1	Default market offer determination for 2019–20
DMO 2	Default market offer determination for 2020–21
DMO 3	Default market offer determination for 2021–22
DMO 4	Default market offer determination for 2022–23
DMO 5	Default market offer determination for 2023–24
DMO 6	Default market offer determination for 2024–25
DMO 7	Default market offer determination for 2025–26
DMO 8	Default market offer determination for 2026–27
DNSP	Distribution network service provider
EBITDA	Earnings before interest, tax, depreciation and amortisation
ECA	Energy Consumers Australia
ESC	Essential Services Commission
GST	Goods and services tax
JEC	Justice and Equity Centre
kWh	Kilowatt hour
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost

Term	Definition
MWh	Megawatt hour
MSATS	Market Settlement and Transfer Solutions
NEM	National Electricity Market
NSLP	Net System Load Profile
NSW	New South Wales
OTC	Over-the-counter
QCOSS	Queensland Council of Social Service
RBA	Reserve Bank of Australia
RET	Renewable Energy Target
SRES	Small-scale Renewable Energy Scheme
SACOSS	South Australian Council of Social Service
SE Queensland	South East Queensland
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 2025 to 30 June 2026 (known as DMO 7).

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] The DMO price also acts as a 'reference price' for all other market offers in each distribution region. DMO prices are designed to aid consumers in comparing energy plans across different providers.

On 13 March 2025 we published the DMO 7 draft determination, setting out our proposed approach and draft prices for DMO 7. Each year the draft determination is subject to public consultation and stakeholder feedback. As with previous determinations, we have considered all feedback and our decisions are reflected in this final determination.

1.1 DMO 7 prices

Final DMO 7 prices for each customer type in each distribution region are set out in chapter 2 (Table 2.1).

In NSW, compared with DMO 6, residential customers without controlled load will see price increases of 8.5% to 9.1% (6.1% to 6.7% above forecast inflation). Customers with controlled load will see price increases of 8.3% to 9.7% (5.9% to 7.3% above forecast inflation). Small business customers will see increases of 7.9% to 8.5% (5.5% to 6.1% above forecast inflation).

In SE Queensland, compared with DMO 6, residential customers without controlled load will see price increases of 3.7% (1.3% above forecast inflation). Customers with controlled load will see price increases of 0.5% (1.9% below forecast inflation). Small business customers will see increases of 0.8% (1.6% below forecast inflation).

In South Australia, compared with DMO 6, residential customers without controlled load will see price increases of 3.2% (0.8% above forecast inflation). Customers with controlled load will see price increases of 2.3% (0.1% below forecast inflation). Small business customers will see increases of 3.5% (1.1% above forecast inflation).

Increases across nearly all cost components have driven these results. Wholesale and network costs have seen moderate increases across nearly all customer types in most regions. Retail costs have seen larger increases in all regions. While this source of costs

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

2 Further information on standing offers and how the DMO protects customers on standing offers can be found in chapter 3.

makes up a smaller portion of the total price, the rate of growth means it has contributed more than other elements to the price rises in some regions.

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

In setting the DMO prices, we must have regard to any matter we consider relevant. One of these matters is electricity affordability, which remains a top cost-of-living issue for households and concern for small businesses and was raised by many stakeholders as part of this process.

Since DMO 6, we have separately calculated a retail margin and a competition allowance. In determining whether to apply the competition allowance, we consider cost-of-living pressures using the Consumer Price Index (CPI) as our primary metric. Where quarterly CPI exceeds the Reserve Bank of Australia's (RBA) target range on a material and sustained basis, we will not include the competition allowance in the DMO prices.

Economic conditions appear to have moderated since DMO 6, with the March 2025 trimmed mean CPI of 2.9% falling marginally within the RBA target band of 2–3% for the first time since December 2021. However, we do not consider that the March 2025 quarter update provides sufficient evidence of sustained easing of cost-of-living pressures. We also note in its May Statement on Monetary Policy the RBA considers the economic outlook remains uncertain.

Consistent with the draft determination, we have decided not to apply a competition allowance in the final determination for DMO 7.

Bill relief, rebates and concessions are offered by the Australian, 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 7 prices

Retail costs are a smaller component of the DMO (around 11% to 16% for residential customers and 6% to 9% for small business). However, this component has undergone the largest increases since DMO 6 (8.3% to 35.4%) and for 6 out of the 15 prices is the largest driver in DMO price increases. This component has increased in DMO 7 due to growing costs reported by retailers, including bad and doubtful debts and implementation of smart meters. Some retailers have also increased spending on acquiring and retaining customers.

We further scrutinised these increases to ensure the retail cost component remained reasonable. To critically examine the reported increases, we issued an additional compulsory information request to the 26 retailers that previously reported retailer cost data that formed the basis for the retail component in the draft determination. In light of the additional information received, we have made some revisions to the retail component of the final DMO prices.

Wholesale costs make up around 31% to 45% of the DMO prices and saw increases of 1.5% to 10% from DMO 6 to DMO 7 depending on region, though some customer types saw decreases of between 0.1% and 0.2%. Increases were primarily driven by contract prices relevant to DMO 7, which retailers use to manage their exposure to wholesale spot market outcomes. Prices of these contracts have remained relatively elevated, which was consistent with higher wholesale spot market prices across 2024. These spot prices were partially driven by a greater frequency of high price events, which resulted from a range of factors including high demand, coal generator and network outages, and low renewable generation output. Spot market conditions have been more benign throughout early 2025, but this has not had a significant impact on expectations for the 2025−26 financial year, and prices for DMO 7 relevant contracts have remained elevated.

Network costs are also a large component of DMO prices, comprising around 33% to 48% of DMO prices. In May 2025, the AER approved network tariff prices from each distribution network service provider (DNSP). This led to changes in the network component of the DMO ranging from a reduction of 6.8% (Energex) to an increase of 11.1% (Endeavour Energy) since DMO 6.

The main drivers for changes in the approved network tariffs for 2025–26 compared with DMO 6 network costs are:

- Increases in network costs for all networks which are driven by the price paths set out in our revenue determinations. These revenue determinations were remade for NSW networks in 2024 and for Queensland and South Australian networks in 2025. In all regions, a key driver of the price paths was market factors (higher actual inflation and interest rates) causing a higher return on capital. Our determinations also included expenditure in important emerging areas such as improved network resilience to address climate change-related risks, the uptake and integration of consumer energy resources (including rooftop solar, batteries and electrical vehicles), and cyber security. In making our revenue determinations, we assess these expenditure proposals to ensure consumers pay no more than necessary for a safe and reliable power supply.
- There were also some specific factors for each region contributing to the network cost aspect of the DMO prices in 2025–26:
  - In NSW, the NSW Roadmap cost increases and higher transmission costs are also contributing to increases. However, forecast increasing energy consumption acts to partially offset price increases for NSW customers.
  - In SE Queensland, the increases are offset by the return of previously over-recovered revenues. Decreases in costs for Queensland residential customers with controlled load reflect lower prices for controlled load tariffs.
  - In South Australia, we included expenditure to improve the management of safety risks to the public and workers. Increases are partially offset by the return of previously over-recovered revenues. Decreases in costs for South Australian residential customers reflect a reduced allocation of transmission costs to the residential flat rate tariff.

Environmental costs are a small component of the DMO at 3% to 4% of the DMO prices. Environmental costs decreased for all customers – by between 18.1% and 19.0% in NSW, 25.9% in South Australia and 27.9% in Queensland. Decreases in costs associated with federal renewable energy target schemes drove decreases in all regions. Decreases in South Australian renewable energy target scheme costs also further contributed to the decreases in South Australia, while an increase in costs of one of the NSW renewable energy target schemes slightly offset the decreases in NSW.

1.4 Our approach to DMO 7

Throughout each DMO process, we consider network, wholesale, environmental and retail operating costs as well as the retail margin and any allowances to determine a reasonable price. For DMO 7, we consulted on the following aspects of the DMO methodology:

- our approach to estimating customer load profiles used within our wholesale cost methodology, noting the changes to the Net System Load Profile (NSLP) and removal of the NSW Controlled Load Profile
- the treatment of solar exports in the load profiles, and whether and how hedging costs related to the impact of solar exports should be reflected
- the South Australia wholesale forecasting methodology given low liquidity in the contract market and other variations to wholesale modelling inputs
- our approach to retail margin and competition allowance
- a methodology to calculate retail costs based on data collected from retailers that captured a broader market share than previous DMO determinations
- whether to calculate network costs solely from flat rate network tariffs or a blend of different network tariffs.

We have summarised key aspects of our final determination below.

1.4.1 Wholesale cost methodology

Load profile assumptions

We have maintained our approach from the draft determination to blend one year of NSLP data (October 2023 to October 2024) with interval meter data to simulate load profiles for all regions. We consider this approach best captures consumption patterns of customers with both accumulation meters and interval meters. With this blended approach, as the smart meter rollout progresses, the methodology will dynamically capture customer transitions to interval meters without methodological changes.

We also decided to maintain a single load profile for residential and small business customers because the NSLP data is not granular enough to distinguish by customer type.

We have maintained our approach of excluding solar exports from the interval meter data used to create the blended load profiles. As the DMO is a price charged by retailers for customers' imports (or consumption), we consider the load profiles used in the wholesale cost methodology should reflect this, noting the NSLP data still reflects some customers' solar exports as they cannot be separated out.

We also hold concerns that including solar exports in the load profiles would lead to an over-recovery of wholesale costs from consumers. This is because our methodology does not account for the value of solar exports (which can be both positive and negative), or load-flattening measures and other strategies that some retailers may employ to different extents to mitigate costs in practice.

We acknowledge some retailers may face some costs arising from solar exports that would not be accounted for in the wholesale cost methodology due to different hedging strategies that are more sensitive to the presence of customers' solar exports. The solar hedging adjustment was introduced in the draft determination to recognise the impact of solar exports on retailer hedging strategies and costs. However, because retailers did not consider it was reflective of the costs they face in practice while consumer groups did not support inclusion of any adjustment, we have removed the adjustment from the DMO 7 final determination.

We do not consider it reasonable to attempt to reflect all potential hedging costs from strategies that differ from the DMO wholesale cost methodology. We also consider that the presence of negative spot prices in the wholesale cost modelling simulations, which increases hedging costs, captures some costs faced by retailers to an extent. Furthermore, the adoption of the 75th percentile estimate of modelled wholesale cost outcomes partly addresses risks retailers may face as a result of solar exports.

As some retailers continue to hold strong views on costs associated with solar exports, we will further evaluate potential hedging costs resulting from solar exports in DMO 8, however we remain cognisant of avoiding an over-recovery of costs from consumers.

NSW controlled load profiles

With the removal of the controlled load profiles in NSW, we decided to maintain our approach of using the Australian Energy Market Operator's (AEMO) historical Controlled Load Profile consistent with previous determinations given the profile shape has not substantially changed for the past few years. As relevant controlled load profile data for the DMO 8 period will not be available, we acknowledge that a new approach will need to be considered, in consultation with stakeholders, for the next DMO determination.

South Australia methodology

Over-the-counter (OTC) contracts comparable to Australian Securities Exchange (ASX) contracts continue to be broadly aligned in terms of volume and price in the South Australian market. Therefore, we have continued to base the wholesale cost methodology for South Australia on publicly available ASX data only.

Variation of modelling inputs

We have not introduced any increased variation in wholesale modelling inputs because we consider doing so would increase subjectivity and complexity in the wholesale cost methodology without materially improving outcomes. This decision has also taken into account stakeholder feedback that there is value in consistency across the wholesale methodology.

1.4.2 Efficient margin and competition allowance

For DMO 7 we have continued the approach adopted in DMO 6, which separately calculates a retail margin and a competition allowance in the DMO prices.

The retail margin is set as a percentage of the DMO price (before a competition allowance). This margin allows retailers to make a reasonable profit when selling electricity to standing offer customers in DMO regions. We have set the margin at 6% of residential prices and 11% of small business prices.

We have also calculated a competition allowance that could be applied after the retail margin is calculated. This reflects the higher costs of some of the smaller retailers in the market that enter and bring competitive tension that benefits customers. However, as described above, we did not apply the competition allowance to final DMO 7 prices.

Continued easing of CPI inflation over successive quarters would provide stronger evidence to include the competition allowance in future DMO determinations.

1.4.3 Network costs

The final determination uses the updated network flat rate tariffs from the final approved tariffs for 2025–26 for all distributors across DMO regions. For DMO 8 we will continue to consult with stakeholders on the feasibility of adopting a blended network cost approach that includes time-of-use and other tariffs in addition to flat rate tariffs.

1.4.4 Environmental costs

For the final determination, we have decided to retain the existing market-based approach to environmental cost forecasting.

1.4.5 Retailer costs

Retail and other costs

We have maintained the approach used in the DMO 7 draft determination using a weighted average of retail and other costs. However, we have revised the retail costs component in our final determination to exclude some costs reported by retailers in a subsequent compulsory information request that we consider not to be reasonable.

Smart meter costs

We have maintained the approach used in the DMO 7 draft determination using a weighted average of smart meter costs reported by retailers. We have updated the calculations of this component with smart meter installation and costs figures at 31 March 2025.

Bad and doubtful debt

We have maintained the approach used in the DMO 7 draft determination using a weighted average of bad and doubtful debt costs reported by retailers. Currently, bad and doubtful debt costs are defined as uncollectable accounts receivable from customers. For DMO 8 we will consider obtaining actual realised bad and doubtful debt figures from retailers to ensure that data collection is consistent across all retailers.

1.5 Looking ahead to DMO 8

Throughout consultation processes across DMO 7 and previous determinations, we have heard consistent feedback from stakeholders on the value of stability within the DMO methodology. This feedback has been taken into account for many decisions in this final determination.

For DMO 8 we will endeavour to hold the methodology stable as much as possible. However, exceptions may occur if market conditions shift substantially or we hold material concerns about a current aspect of the methodology that needs to be reconsidered or refined.

Based on our process for the DMO 7 final determination, we intend to focus on the below aspects of the methodology for DMO 8 while also taking into account the relevant regulatory environment:

- impact of solar exports on treatment of risks in the wholesale methodology
- the treatment and simulation of controlled load in the wholesale methodology
- whether to obtain actual bad and doubtful debt figures from retailers to ensure that data collections is consistent across all retailers
- whether to adopt a blended network cost approach
- how to best incorporate the data reported by a wide range of retailers to ensure retail costs remain reasonable.

2 DMO 7 final prices

Final DMO prices for 2025–26 for each customer type in each distribution region are set out in Table 2.1. The table also shows the changes from DMO 6 in both real terms (that is, adjusted for forecast inflation) and nominal terms.

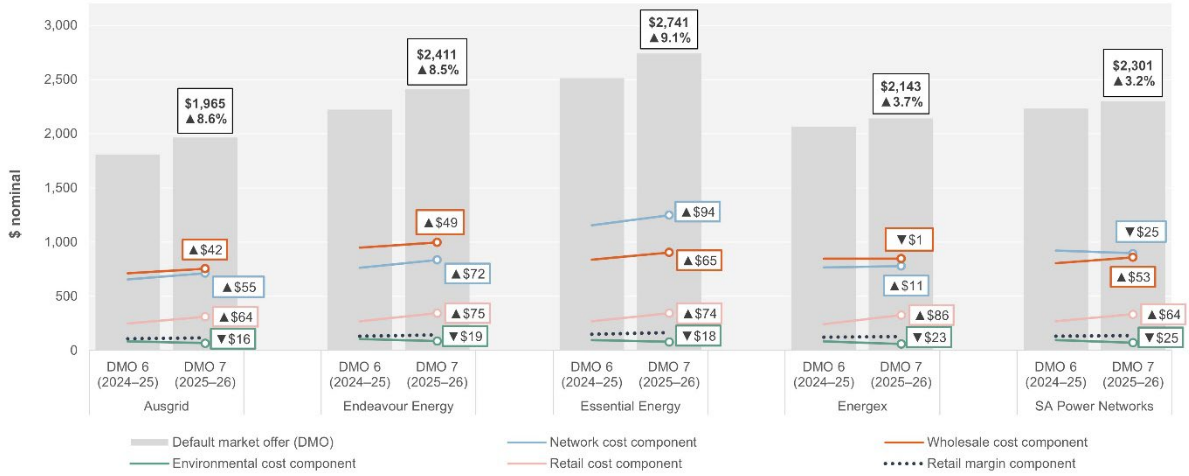
Table 2.1 DMO 2025–26 final determination prices, including changes from DMO 6 (nominal and real terms, inc. GST)

Distribution region	Description	Residential (without controlled load)		Residential (with controlled load)		Small business (without controlled load)	
Ausgrid	DMO price		$1,965		$2,717		$4,977
	For annual usage of		3,900 kWh		Flat rate 4,800 kWh + CL 2,000 kWh		10,000 kWh
	Change y-o-y	+$155	(8.6%)	+$208	(8.3%)	+$365	(7.9%)
	Change y-o-y (real)	+$112	(6.2%)	+$148	(5.9%)	+$254	(5.5%)
Endeavour Energy	DMO price		$2,411		$3,072		$4,775
	For annual usage of		4,900 kWh		Flat rate 5,200 kWh + CL 2,200 kWh		10,000 kWh
	Change y-o-y	+$188	(8.5%)	+$271	(9.7%)	+$353	(8.0%)
	Change y-o-y (real)	+$135	(6.1%)	+$204	(7.3%)	+$247	(5.6%)
Essential Energy	DMO price		$2,741		$3,211		$6,222
	For annual usage of		4,600 kWh		Flat rate 4,600 kWh + CL 2,000 kWh		10,000 kWh
	Change y-o-y	+$228	(9.1%)	+$280	(9.6%)	+$489	(8.5%)
	Change y-o-y (real)	+$168	(6.7%)	+$210	(7.2%)	+$351	(6.1%)
Energex	DMO price		$2,143		$2,425		$4,294
	For annual usage of		4,600 kWh		Flat rate 4,400 kWh + CL 1,900 kWh		10,000 kWh
	Change y-o-y	+$77	(3.7%)	+$11	(0.5%)	+$33	(0.8%)
	Change y-o-y (real)	+$27	(1.3%)	-$47	(-1.9%)	-$69	(-1.6%)
SA Power Networks	DMO price		$2,301		$2,824		$5,541
	For annual usage of		4,000 kWh		Flat rate 4,200 kWh + CL 1,800 kWh		10,000 kWh
	Change y-o-y	+$71	(3.2%)	+$64	(2.3%)	+$189	(3.5%)
	Change y-o-y (real)	+$17	(0.8%)	-$2	(-0.1%)	+$61	(1.1%)

Note: CL refers to Controlled Load. Real comparisons with DMO 6 are based on RBA 2024–25 inflation forecast of 2.4% in its February 2025 Statement on Monetary Policy.

Figure 2.1 shows the movement in the DMO cost components since DMO 6. It illustrates that all cost components, except for environmental costs, network costs in South Australia and wholesale costs in Queensland, have increased for residential customers without controlled load. Further detail on each of these cost components is provided in chapters 4 to 8 of this determination.

Figure 2.1 Composition of the default market offer (DMO 6 and DMO 7 (nominal terms))



Note: Prices displayed are for residential customers without controlled load.

3 Role of the AER

As an 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, and we regulate electricity networks and gas pipelines in all jurisdictions except Western Australia.

Under the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (the Regulations), we are also responsible for setting the DMO price each year in NSW (Endeavour Energy, Essential Energy and Ausgrid distribution networks), SE Queensland (Energex distribution network) and South Australia (SA Power Networks distribution network).

3.1 DMO regulatory framework

The DMO price applies to residential and small business customers on standing offers in NSW, SE Queensland and South Australia. The DMO price does not apply in the ACT, Northern Territory, regional Queensland, Tasmania, Victoria or Western Australia because maximum standing offer prices in those regions are set by or under a law of a state or territory.[3]

Part 3 of the Regulations requires us 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)[4]
- 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).[5]

The Regulations set out that we must determine DMO prices for the following types of small customers:[6]

- residential customers – on flat rate or time of use (TOU) tariffs
- residential customers with controlled load – these are separately metered tariffs used for appliances such as electric hot water storage systems, pool pumps or underfloor heating
- small business customers – on flat rate tariffs.[7]

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3 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.

4 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.

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

6 Regulations, s. 6.

7 Small business customers are those that use less than 100 MWh per year. We are not required to determine an annual price and usage for small business customers on other tariff types, such as small business controlled load and TOU tariffs.

The DMO does not apply to customers if they are on a tariff with a demand charge, they have a prepayment meter or are in an embedded network served by an authorised retailer.[8]

To determine a reasonable annual price, the Regulations require us to have regard to a range of specific matters and costs:[9]

- the prices electricity retailers charge for supplying electricity in the region to that type of small customer
- the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region
- the cost of distributing and transmitting electricity in the region
- the wholesale cost of electricity in the region
- the cost of complying with the laws of the Commonwealth and the relevant state or territory in relation to supplying electricity in the region
- if relevant to the region, the cost of acquiring and retaining small customers (which is the case in all DMO regions)
- the cost of serving small customers.

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.[10] This includes requirements for standing offer prices to not exceed the DMO, small customers to be told how a retailer's prices compare with the DMO, and how conditional discounts are presented in advertisements.[11] 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.

8 Regulations, s. 6.

9 Regulations, s. 16(4).

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

11 Regulations, s. 10, 12, 14.

3.2 Policy objectives guide the DMO

When the DMO Regulations were introduced, the government of the time also provided policy objectives.[12] These policy objectives are the matters we consider relevant when setting a reasonable price:[13]

PROTECT

Protect consumers from unreasonable prices in the market by reducing unjustifiably high standing offer prices.

ALLOW

Allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention.

MAINTAIN

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

Throughout 2023–24, during the period before the DMO 6 final determination, we received letters from the Australian and state governments encouraging the AER to have regard to matters we consider relevant under the discretion afforded to us in the Regulations. These letters included requests for the AER to take into account broader economic conditions and acute periods of cost-of-living pressures for consumers.[14] The Australian Government Minister for Climate Change and Energy's letter at the time noted the request was a temporary measure to lessen the impacts of electricity bills on customers where the DMO applies, and to be considered on balance with the objectives.[15] In April 2025 we received a letter from the NSW Minister for Energy reiterating these requests.[16] In the 14 March Energy and Climate Change Ministerial Council Meeting communique, Ministers also encouraged the AER to further consider ongoing cost-of-living pressures in settling the final DMO.[17] While this was not a submission to DMO 7, we have taken this communique into account in our final decision.

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12 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.

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

14 The Hon Chris Bowen MP, Minister for Climate Change and Energy, Submission to DMO 6 issues paper, 2023; The Hon Penny Sharpe MLC, Minister for Energy, Submission to DMO 6 issues paper, 8 November 2023; The Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Submission to DMO 6 issues paper, 29 February 2024; The Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Submission to DMO 6 issues paper, 5 March 2024; South Australian Department for Energy and Mining, Submission to DMO 6 issues paper, 10 November 2023; The Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Submission to DMO 6 draft determination, 9 April 2024; South Australian Department for Energy and Mining, Submission to DMO 6 draft determination, 9 April 2024.

15 The Hon Chris Bowen MP, Minister for Climate Change and Energy, Submission to DMO 6 issues paper, 2023.

16 The Hon Penny Sharpe MLC, Minister for Energy, Submission to DMO 7 draft determination, 10 April 2025.

17 DCCEEW, Energy and Climate Change Ministerial communique, Department of Climate Change, Energy, the Environment and Water, 14 March 2025.

When determining a reference price, we must meet the requirements of the Regulations. In considering how best to do this, we weigh up the policy objectives, including the advice we receive from governments on these, and economic conditions for consumers and energy retailers.

How the DMO differs from other state and territory reference price 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).

A key difference is that the Regulations require the DMO to be a 'reasonable' price whereas regulatory frameworks in other regions target an efficient price. For regional Queensland, the ACT and Tasmania, where there is limited retail electricity competition, 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'.[18] However, the VDO is different from the DMO because the pricing order requires ESC to:

- base VDO prices on the efficient costs of the sale of electricity by a retailer
- not include headroom, which is defined as an allowance that does not reflect efficient costs
- only include modest costs for consumer acquisition and retention.[19]

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18 Essential Services Commission, Victorian Default Market Offer 2024–25 Final Decision Paper, 20 May 2024, p. 3.

19 Order made pursuant to s. 13, Electricity Industry Act 2000.

3.3 Standing offer customers

All customers have the right to choose a standing offer. However, the most common reasons for being on a standing offer are:

- 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[20]
- have defaulted to a standing offer following the expiry of a market contract.[21]

> Every retailer must have a standing offer and customers have the right to ask for one.[22]
>
> However, for those customers with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms.[23] 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.[24]

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

21 Section 10 of the Regulations makes clear the DMO price only applies to customers on an electricity retailer's standing offer. It does not apply to customers who are on ongoing market contracts where discounts have expired.

22 National Energy Retail Law s. 23 and s. 25.

23 National Energy Retail Law s. 22.

24 ACCC and AER, Joint Compliance Bulletin, Australian Competition and Consumer Commission and Australian Energy Regulator, 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 regions. 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 regions

Customer type	DMO	NSW (number and % of customers)	SE Queensland (number and % of customers)	South Australia (number and % of customers)	Total standing offer customers (number and % of customers)
Residential customers	DMO 7	278,868 (8.0%)	136,032 (8.9%)	60,827 (7.4%)	**475,727 (8.2%)**
Small business customers	DMO 7	56,373 (18.1%)	20,539 (17.5%)	14,148 (16.2%)	**91,060 (17.6%)**
Residential customers	DMO 6	293,470 (8.6%)	140,713 (9.4%)	61,701 (7.6%)	**495,884 (8.6%)**
Small business customers	DMO 6	57,093 (18.2%)	23,106 (19.7%)	14,600 (16.7%)	**94,799 (18.3%)**
Residential customers	DMO 5	320,362 (9.4%)	156,986 (10.5%)	62,600 (7.8%)	**539,948 (9.5%)**
Small business customers	DMO 5	55,995 (18.1%)	21,267 (19.3%)	13,778 (15.9%)	**91,040 (18.0%)**
Residential customers	DMO 4	347,483 (10.4%)	167,520 (11.5%)	65,516 (8.2%)	**580,519 (10.4%)**
Small business customers	DMO 4	64,211 (19.2%)	24,234 (21.7%)	13,701 (15.6%)	**102,146 (19.1%)**

Note: SE Queensland figures extrapolated from all of Queensland by excluding Ergon Energy customers. Other retailers have customers in regional Queensland, so Queensland figures are approximate. Standing offer customers have been calculated by subtracting market offer customers from total customers.
Source: AER retail market performance update, Quarter 2 2024–25.

4 Network costs

- For the DMO 7 final determination we have decided that a flat rate network cost approach remains the most appropriate methodology.
- Network costs make up between 33% and 48% of the DMO 7 prices.
- Network prices are increasing across all distribution regions, customer types and tariff structures except Energex residential with controlled load and SA Power Networks residential with and without controlled load. Increases are between 1.4% and 11.1% and decreases between 2.7% and 6.8%.

The Regulations direct the AER to have regard to the cost of distributing and transmitting electricity in the region[25] when considering what would be a reasonable per-customer price for supplying electricity in that region.[26] The Regulations also direct the AER to have regard to the prices retailers charge for supplying electricity.[27]

Under the National Electricity Rules, the AER regulates network charges by approving the network tariffs that distribution network businesses set on an annual basis.[28] The DMO network cost component is adjusted each year to reflect changes in distributor network costs for each customer type under the DMO.

The network costs used in the final determination are the approved network tariffs for 2025–2026. 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

Network businesses provided the AER with updated indicative network tariffs in February 2025, which we used in the draft determination to calculate the indicative network costs for 2025–26. That approach enabled us to consider the most up-to-date inflation forecasts,

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25 Regulations, s. 16(4)(c)(ii).

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

27 Regulations, s. 16(4)(a).

28 National Electricity Rules 2025, clause 6.18.2.

interest rates, cost of capital and other factors that drive network tariffs. NSW DNSPs developed indicative network tariffs for the draft determination that included the recovery of the 2025–26 NSW Roadmap costs.

In the draft determination, it was our position to use approved network flat rate tariffs for 2025–26 for the final DMO 7 price calculation.[29] We considered that this approach remained the most appropriate methodology for DMO 7. We acknowledged the perspective that including a blended network cost is now likely more reflective of an actual retailer's circumstances, but altering our approach would add complexity and reduce transparency without providing major benefits to stakeholders.

4.2 Stakeholder views

In response to the draft determination, 8 submissions mentioned different topics related to network costs.

EnergyAustralia and Origin Energy were generally supportive of the approach taken by the AER in maintaining the use of flat rate network tariffs for the draft determination.[30]

ENGIE, 1st Energy, Alinta Energy, Origin Energy, Red Energy and Lumo Energy all commented that with the increased installation of smart meters and the reassignment of customers onto time of use and other network tariffs, a flat rate approach is becoming less reflective of costs that retailers actually incur. None of the retailers specifically suggested that a blended approach be considered for DMO 7 and all were supportive of a blended approach being explored for DMO 8 and future determinations.[31]

1st Energy, Powershop/Shell Energy, Red Energy and Lumo Energy highlighted in their submissions an upcoming risk of a network-retail tariff mismatch, which they believe will result in retailers facing higher costs, due to the accelerated smart meter deployment and associated consumer protections.[32]

Powershop/Shell Energy raised a further risk in terms of the accuracy of the 5-year revenue determinations of network business.[33] They noted that, given that network costs comprise a significant proportion of the DMO total cost stack and due to network costs steadily increasing year-on-year since 2021, accuracy and accountability in the forecast bill impacts defined in the 5-year network pricing determinations is essential. Powershop/Shell Energy submitted that the AER is well placed to conduct an annual review comparing the network pricing determination pass-through and estimated bill impacts in the DMO with the actual bill

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29 AER, DMO 7 draft determination, Australian Energy Regulator, 13 March 2025, pp. 17–18.

30 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 6; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 8.

31 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 7; 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, p. 2; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 3; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 8; Red Energy and Lumo Energy, Submission to the DMO 7 draft determination, 3 April 2025, p. 3.

32 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, p. 2; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 3; Red Energy and Lumo Energy, Submission to the DMO 7 draft determination, 3 April 2025, p. 3.

33 Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 3.

impacts incurred by retailers to see if these amounts reconcile, or if retailers incur greater network costs than allocated in the DMO network cost component and DMO price.

The joint submission made by the Justice and Equity Centre, Australian Council of Social Service, South Australian Council of Social Service and Queensland Council of Social Service (JEC/ACOSS/SACOSS/QCOSS) also commented on network costs. The submission noted that although the scope to lower network costs functionally sits outside the DMO process, they recommended the AER support measures to reduce this cost by asking the Energy and Climate Change Ministerial Council to review cost recovery for large transmission investments and Renewable Energy Zone infrastructure to ensure fairer cost sharing.[34]

4.3 Final determination

We have determined that using the approved flat rate network tariff prices remains the most appropriate methodology to calculate the DMO network component in each of the 5 distribution regions.

In response to the submissions received from retailers regarding a change in methodology to a blended network tariff (section 4.2), we discussed in the draft determination and the issues paper for DMO 7 several significant challenges to being able to implement this change for DMO 7.

These challenges include:

- **Energex's and SA Power Networks' revenue resets.** The network revenue resets would have introduced a challenge in obtaining timely and accurate additional network tariff, customer numbers and consumption information required to calculate blended network costs. This will not be an issue in the next 3 determinations because none of the DMO regions will be undergoing revenue resets during this period.
- **Deriving appropriate weightings for blending small business network tariffs.** The small business DMO price only applies to small business flat rate retail tariffs and the AER currently does not have network tariff information for the subset of small business customers on flat rate retail tariffs. With the AER's new retail performance reporting guidelines being implemented from Q1 2025–26, the greater granularity of network and retail tariffs should facilitate the development of suitable weightings for a blended network tariff to address this issue for DMO 8 and future determinations.

The AER acknowledges that a significant proportion of customers are already on cost-reflective tariffs. With the accelerated smart meter deployment rule change[35] coming into effect in December 2025, this proportion will continue to increase. The AER believes that these challenges should lessen for DMO 8 and will continue to explore this methodological change for DMO 8.

In response to the submissions received from retailers that they will face increased costs and risk from a network-retail tariff mismatch, the AER does not consider that retailers will be

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[34] JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 8.

[35] AEMC, National Electricity Amendment (Accelerating Smart Meter Deployment) Rule, Australian Energy Market Commission, 28 November 2024.

uniformly worse off facing a cost-reflective tariff that they cannot pass onto the customer. That is, costs may go up for some customers but down for others. We also maintain our view that retailers have a range of options to help manage cost risks, including working with customers to change consumption behaviour by providing helpful information and new products and services. The AER does acknowledge that retailers may face some new costs to comply with the associated consumer protections but considers that these costs would be captured by our retail cost information request. These costs would be reflected in the calculation of the retail and other cost component rather than network costs.

The approved flat rate network tariffs have varied from the indicative network tariffs that were the basis of the draft determination network component. Compared with the DMO 7 draft determination estimates, the final network costs for DMO 7 are:

- 0.3% to 1.1% lower for the Ausgrid (NSW) region
- 0.5% to 0.9% lower for the Endeavour Energy (NSW) region
- 0.3% to 0.6% higher for the Essential Energy (NSW) region
- 1.2% to 5.0% lower for the Energex (SE Queensland) region
- 0.4% to 0.8% lower for the SA Power Networks (South Australia) region.

The main drivers for changes in the approved network tariffs for 2025–26 compared with DMO 6 network costs are:

- Increases in network costs for all networks which are driven by the price paths set out in our revenue determinations. These revenue determinations were remade for NSW networks in 2024 and for Queensland and South Australian networks in 2025. In all regions, a key driver of the price paths was market factors (higher actual inflation and interest rates) causing a higher return on capital. Our determinations also included expenditure in important emerging areas such as improved network resilience to address climate change-related risks, the uptake and integration of consumer energy resources (including rooftop solar, batteries and electrical vehicles), and cyber security. In making our revenue determinations, we assess these expenditure proposals to ensure consumers pay no more than necessary for a safe and reliable power supply.
- There were also some specific factors for each region contributing to the network cost aspect of the DMO price in 2025–26:
  - In NSW, the NSW Roadmap cost increases and higher transmission costs are also contributing to increases. However, forecast increasing energy consumption acts to partially offset price increases for NSW customers.
  - In SE Queensland, the increases are offset by the return of previously over-recovered revenues. Decreases in costs for Queensland residential customers with controlled load reflect lower prices for controlled load tariffs.
  - In South Australia, we included expenditure to improve the management of safety risks to the public and workers. Increases are partially offset by the return of previously over-recovered revenues. Decreases in costs for South Australian residential customers reflect a reduced allocation of transmission costs to the residential flat rate tariff.

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 7 charts in Appendix D. The DMO 7 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 flat – EA010	Controlled Load 1 – EA030 Controlled Load 2 – EA040	Small business flat – EA050
Endeavour Energy	Residential Flat – N70	Controlled Load 1 – N50 Controlled Load 2 – N54	General Supply Block – N90
Essential Energy	LV Residential Anytime – BLNN2AU	LV Controlled Load 1 – BLNC1AU LV Controlled Load 2 – BLNC2AU	LV Small Business Anytime – BLNN1AU
Energex	Residential Flat – SAC8400	Controlled Load 1 (Super Economy) – SAC9000 Controlled Load 2 (Economy) – SAC9100	Small Business Flat – SAC8500
SA Power Networks	Residential Single Rate RSR (SR)	Residential Single Rate RSR (controlled load)	Business Single Rate – BSR

Total network cost components for the 2025–26 DMO 7 are set out in Table 4.2, together with the comparative costs used for the 2024–25 DMO 6.

Table 4.2 Total network costs for 2024–25 and 2025–26 ($ nominal, inc. GST)

Distribution region	Tariff	2024–25 $	2025–26 $	Change: year-on-year $	%
Ausgrid	Residential flat rate	657	712	55	8.4
	Residential controlled load	855	925	70	8.2
	Small business 10,000kWh	1,756	1,923	167	9.5
Endeavour Energy	Residential flat rate	765	837	72	9.4
	Residential controlled load	934	1,038	103	11.1
	Small business 10,000kWh	1,454	1,598	144	9.9
Essential Energy	Residential flat rate	1,155	1,249	94	8.1
	Residential controlled load	1,276	1,383	107	8.4
	Small business 10,000kWh	2,743	2,959	216	7.9

Distribution region	Tariff	2024–25 $	2025–26 $	Change: year-on-year $	Change: year-on-year %
Energex	Residential flat rate	768	778	11	1.4
	Residential controlled load	870	811	-59	-6.8
	Small business 10,000kWh	1,475	1,506	31	2.1
SA Power Networks	Residential flat rate	922	897	-25	-2.7
	Residential controlled load	1,105	1,073	-32	-2.9
	Small business 10,000kWh	2,206	2,282	76	3.4

Note: Total network costs contain a fixed and variable component and are a function of usage.

5 Wholesale energy costs

For the DMO 7 final determination we have decided to:

- use one year of Net System Load Profile (NSLP) data to simulate the load profiles, blended with interval meter data
- maintain a single load profile for residential and small business customers
- continue to exclude solar exports from the interval meter dataset used to create the load profiles
- remove the solar hedging adjustment introduced in the DMO 7 draft determination
- use the historical Controlled Load Profile to simulate the controlled load shape for NSW
- continue to base the wholesale cost methodology for South Australia on publicly available ASX data
- maintain all other aspects of the wholesale cost methodology, including the 75th percentile of modelled wholesale cost outcomes and book build approach.

Wholesale costs represent approximately 31% to 45% of the DMO 7 prices. For the majority of regions and customer types, wholesale costs and have increased by between 1.5% and 10% since DMO 6. In SE Queensland, wholesale costs have slightly decreased (up to 0.2%) for some customer types.

The Regulations direct the AER, in determining what it considers to be a reasonable per customer annual price for supplying electricity, to have regard to the wholesale cost of electricity.[36] The AER must also have regard to the prices that retailers charge for supplying electricity,[37] the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying energy[38] and other matters we consider relevant such as the DMO policy objectives.[39]

When considering the wholesale cost of electricity and establishing a reasonable forecast of wholesale costs for the DMO, we aim to reflect how a prudent retailer might purchase energy. This is reflected in the wholesale methodology, which involves forecasting demand (also known as load) and electricity spot market outcomes, as well as building a hypothetical hedging strategy to protect the retailer and its customers against the extreme price volatility that can occur in the wholesale spot market.

The largest component of our wholesale cost forecast is the wholesale energy cost (WEC), which is a function of energy supply and demand forecasts, the assumed hedging strategy of a retailer to manage their exposure to the spot market and any final exposure to the spot market. Additional minor components also relevant to the wholesale cost of electricity, such

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36 Regulations, s. 16(4)(c)(i).

37 Regulations, s. 16(4)(a).

38 Regulations, s. 16(4)(b).

39 Regulations, s. 16(4)(d).

as ancillary and prudential costs, are added to the WEC to determine the final wholesale costs in the DMO. We use an external consultant, ACIL Allen, to assist us with determining wholesale costs in the DMO.

Each year we consult on aspects that form the basis of our methodology for forecasting wholesale costs, such as datasets used to simulate the load profile of a prudent retailer. Our consideration of these aspects is discussed throughout sections 5.1 to 5.3 of this chapter. Section 5.4 includes final wholesale costs for DMO 7 in accordance with the methodology discussed throughout the chapter. It also discusses key drivers of changes in wholesale costs, such as contract price movements.

5.1 Draft determination

5.1.1 Load profile assumptions

Net System Load Profile and interval meter data

Previously our methodology has relied on at least 2 years of Net System Load Profile (NSLP) data to model the costs to retailers of purchasing energy for residential and small business customers. This data includes the aggregated electricity consumption of all customers with accumulation meters. For DMO 6, we blended NSLP data with interval meter data for the first time to ensure interval meter customers were captured in our methodology alongside accumulation meter customers represented by the NSLP. A time series of 2 years of data has historically been used to ensure atypical events do not have an outsized impact on the simulated load profiles.

Due to adjustments made to the NSLP data by AEMO to resolve settlement issues in the SA Power Networks and Energex regions across the previous 2 to 3 years, we considered alternatives to our standard 2-year approach to simulate the load profiles for DMO 7.[40] In making the draft determination, we considered options and stakeholder feedback against decision-making factors including reflection of market outcomes, data transparency and longevity of the decision.

For the DMO 7 draft determination we decided to use one year of NSLP data (October 2023 to October 2024) blended with interval meter data to simulate the load profiles for all regions. We considered this approach most appropriate because it would:

- best reflect market outcomes and the load shape a retailer would need to hedge against during the DMO 7 period – it captured the usage profile of both accumulation and interval meter customers, which we considered important because roughly half of small customers in DMO regions still have their energy usage reflected in the NSLP and some retailers continue to use the NSLP as an input into hedging strategies
- provide transparency to stakeholders – the interval meter data requested from AEMO was published alongside the DMO 7 draft determination and the NSLP data remained publicly available for stakeholder consideration

40 AER, DMO 7 issues paper, Australian Energy Regulator, 11 October 2024, pp. 11–17.

- allow us to revert to our standard approach of using 2 years of blended NSLP and interval meter data for the load profiles in DMO 8, without being impacted by previous adjustments to the NSLP.

We were satisfied there was suitable variation in the one-year time series of data in terms of factors such as weather outcomes and regional demand. We were also satisfied the NSLP data remained appropriate for use due to the third adjustment having no discernible impact on overall volumes and the average time of day shape.

We also proposed to maintain a single load profile for residential and small business customers because these profiles could not be individually distinguished within the NSLP data without introducing estimation and uncertainty.

Solar PV exports and hedging costs

Exclusion of solar exports from the interval meter dataset

In the DMO 7 draft determination we maintained the methodology from DMO 6 that excludes small customer solar exports from the interval meter data used to simulate the load profiles. As the DMO is a price charged by retailers for customers' imports (or consumption), we considered that the wholesale cost methodology should be consistent.

While we acknowledged retailers are settled on the net load, which includes solar exports, we considered a load profile that included solar exports would overstate the costs of the daytime carve-out for retailers. We maintained the view that retailers continue to have alternative strategies available to flatten or manage their respective loads to varying extents that cannot be accounted for within the wholesale cost methodology. Including solar exports without accounting for available measures such as adjustments to feed-in tariffs and hot water orchestration, combined with other customer demand that is satisfied by customers exporting behind a Transmission Node Identifier, would have resulted in a wholesale cost above what could be reasonably expected to occur.

We also considered that feed-in tariffs provide an additional potential mechanism for taking into account any retailer cost exposure arising from small customer solar exports combined with negative wholesale spot prices. However, the Regulations state that we must disregard any amount a retailer pays in feed-in tariffs.[41]

Hedging costs arising from solar exports

We recognised that the presence of solar exports changes the wholesale risk profile for retailers and proposed a solar hedging adjustment in the DMO 7 draft determination.

This involved comparing WEC estimates on a load profile that excluded exports, but from 2 modelled hedging strategies – one for a profile including solar exports and another excluding them. Overall, it aimed to reflect that a retailer's hedging product mix could change when considering the presence of solar exports, and then approximate this difference within the wholesale cost methodology.

The hedging adjustment resulted in very minor decreases in the WEC for all regions except for Energex, which increased by $2.15 per megawatt hour (MWh). The small impacts on the

41 Regulations, s. 8A.

WEC reflected that there was only a small change to the hedging strategy when exports were included because the evening consumption peak where prices are often highest still needed to be hedged for. The modelled hedging strategy including solar exports had less weighting of base futures and a greater weighting of caps overall. The impact in Energex was larger due to the modelled retailer receiving less in base futures difference payments in the region under the solar hedging adjustment scenario. For all regions, higher cap premiums under the solar hedging adjustment scenario were largely or completely offset by increases in modelled cap payouts, resulting in minimal impact on WEC estimates overall.

Impacts of the hedging adjustment also differed across regions due to fluctuating spot market modelling outcomes and variations in contract prices influencing the final adjustment value. Therefore, we noted it was possible for the size and direction of the adjustment to dynamically shift between the draft and final determinations for DMO 7.

While we acknowledged that the fluctuating nature of the adjustment reflected complexities in hedging, we were aware it may not have been reflective of costs retailers face in practice. Therefore, we sought views from stakeholders on whether it was appropriate to include this adjustment in the final determination for DMO 7 and whether we should consider alternative approaches to capture hedging costs arising from customers' solar exports.

5.1.2 Controlled Load Profile (NSW)

In previous determinations our methodology relied on AEMO's Controlled Load Profile to simulate the shape of controlled load demand in each region. As detailed in the draft determination, publication of AEMO's Controlled Load Profile has been discontinued in NSW, with accumulation meter controlled load now being settled against the NSLP. This change meant we needed to consider how to best simulate the controlled load profiles for NSW in DMO 7.

For the draft determination we proposed to continue to use the historical Controlled Load Profile as published by AEMO to simulate the controlled load profiles for NSW regions. We considered this maintained consistency in the methodology while the reference data remained current, being less than one year old. We considered it was unclear how the settlement of controlled load against the NSLP had changed the cost of hedging, and of the available options, this would provide the most accurate representation of controlled load consumption patterns.

This assessment of accuracy was informed by additional interval meter controlled load consumption data provided by NSW distribution businesses. The daily shape of this data was similar to AEMO's most recently published Controlled Load Profile, indicating that controlled load consumption patterns have not changed materially since publication of AEMO's Controlled Load Profile ceased. Conversely, other approaches considered such as blending the Controlled Load Profile with the NSLP or using the general use profile resulted in unrealistically peaky load shapes because of the greater volume of general use energy in these profiles. These approaches would have resulted in significantly inflated controlled load WEC estimates. Given alignment of AEMO's discontinued Controlled Load Profile with those provided by NSW distribution businesses, and the recency of the data, we considered maintaining use of AEMO's published Controlled Load Profile the most accurate and transparent option available.

Our draft determination also recognised that the methodology does not currently capture the growing utility of interval meter controlled load. Interval meter controlled load represents about half of controlled load National Metering Identifiers in NSW and the ongoing smart meter rollout will further increase this proportion. Unlike accumulation meter controlled load, interval meter controlled load can be orchestrated. Distribution businesses have indicated that retailers are increasingly orchestrating interval meter controlled load strategically during periods of negative prices or low demand, potentially lowering the retailer's wholesale cost.

We acknowledged that it will be necessary to depart from this methodology in future DMO determinations as AEMO's historical data becomes outdated. Further, we considered interval meter controlled load customers should also be reflected in the methodology. We flagged our intention to work with AEMO and distribution businesses to develop options for the treatment of controlled load in future determinations, in consultation with stakeholders.

5.1.3 South Australian wholesale methodology

The DMO 7 draft determination maintained the use of ASX data, using base futures (including volume arising from the exercise of options), caps and premiums for call options to forecast wholesale costs for the South Australia region. Due to ongoing concerns about market liquidity, we collected confidential over-the-counter (OTC) information in conjunction with a repeat of the long run marginal cost (LRMC) modelling for South Australia as comparative data points against the wholesale cost outcome.

We collected OTC contract market data from South Australian market participants for trades falling within the previous 3 years relevant to the DMO 7 period. Our analysis found OTC contracts continue to be broadly aligned with ASX-traded prices and volumes. Based on this, we maintained our approach and relied on publicly available data from the ASX for the wholesale cost methodology for the draft determination.

In line with our ongoing concerns about low market liquidity in the region, we requested ACIL Allen repeat the LRMC modelling. The LRMC analysis was based on the 2024 AEMO Integrated System Plan 'step change' scenario data, using both greenfield (creating generation to meet supply at least cost) and brownfield (based on current generation fleet) options. The results were then scaled down to the South Australian load profiles to produce WEC estimates. The DMO 7 draft determination WEC estimate sat between the greenfield and brownfield LRMC, reflecting a largely consistent trend with DMO 6. Despite some changes in the drivers of the LRMC estimates, the consistency in the results affirmed the value of using LRMC as a reference point for wholesale costs in South Australia.

Both results from the LRMC and OTC data analysis provided helpful context in a market of low liquidity, supporting the decision to maintain the use of ASX data for the wholesale cost methodology in the draft determination.

We also stated in the draft determination 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.

5.1.4 Inputs into wholesale modelling

The draft determination proposed maintaining fixed fuel price and outage rate inputs in the wholesale modelling. We considered that further varying these inputs would conflict with broader stakeholder feedback, emphasising the importance of consistency, transparency and objectivity.

We considered that any potential for improved accuracy gained by further varying fuel inputs would be outweighed by the additional complexity and subjectivity it introduced. Our consultant evaluated the potential impact of varying fuel prices through remodelling the DMO 6 WEC with additional higher and lower fuel price scenarios. The results indicated that varying fuel inputs did not materially impact the DMO 6 WEC, despite the additional inputs being upwardly biased. We also noted that historical data may contradict the forward price curve in any given year, and specific fuel costs differ among scheduled generation assets due to longer-term fuel contracts and their exposure to international fuel prices. We did not consider a transparent, predictable and objective method for quantifying how fuel price inputs should be varied was readily available.

Given the immaterial impact of introducing further varied fuel inputs and the additional complications this would introduce to the methodology, we proposed to maintain the current array of fuel price inputs.

For outage rates, we considered the current approach already incorporates appropriate variability. The model's outage rates align with AEMO's Integrated System Plan, which incorporates the increasing outage rates observed in recent years. Additionally, the model accounts for existing long-term outages. Similarly to additionally varied modelling inputs, we considered that any additional accuracy resulting from changes to the modelled outage rate would be offset by the additional complexity and subjectivity introduced to the wholesale model.

5.1.5 Other wholesale cost issues

The DMO 7 draft determination discussed the treatment of a range of other aspects of the wholesale cost methodology:

- **75th versus 95th percentile:** We maintained our approach of using the 75th percentile of modelled wholesale cost 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. We also did not think it was appropriate to change to the 95th percentile to address other wholesale cost methodology issues, such as hedging costs arising from solar exports and variation to modelling inputs.
- **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 7 period.
- **ASX options:** We maintained our treatment of options, including the volume of base futures traded as a result of the exercise of base strip options at the trade-weighted strike price. We also included the trade-weighted average premium attached to all exercised and expired call options. Overall, we considered that ASX options are a valuable indicator of the overall cost of energy, noting that retailers commonly use options as a hedging tool.
- **Treatment of compensation costs:** The DMO 7 draft determination reflected known compensation costs awarded by the Australian Energy Market Commission (AEMC)

since the DMO 6 final determination data cut-off date (3 May 2024). This included compensation awarded to Origin Energy and EnergyAustralia Ecogen in September 2024 as a result of the June 2022 market events.[42]

- **AEMO fees:** We maintained our approach to AEMO fees from DMO 6 in the DMO 7 draft determination. To capture the fixed component of AEMO fees, we adjusted the methodology in DMO 6 to include this additional cost as a fixed annual dollar per customer amount. For the DMO 7 draft determination this was $11.99. We also continued to capture the variable costs as directly expressed by AEMO.
- **AEMO prudential requirements:** We maintained our approach from DMO 6 in the DMO 7 draft determination, where ACIL Allen's estimation of prudential costs reflected winter and non-winter months in line with AEMO's prudential requirements.
- **Unaccounted for energy:** We maintained our approach to not make an allowance associated with unaccounted for energy. We considered limited data is available publicly to determine the materiality of these costs and expected unaccounted for energy to be a very small percentage of total distribution losses.

5.2 Stakeholder views

5.2.1 Load profile assumptions

Net System Load Profile and interval meter data

Five retailers supported the approach in the draft determination to use a one-year blend of NSLP and interval meter data to simulate the load profiles.[43] Reasoning included that this approach best captures the respective usage profiles of both accumulation meter and interval meter customers and more accurately reflects a prudent retailer's hedging practices. Stakeholders also noted that earlier concerns with the NSLP data had not materialised. However, EnergyAustralia additionally considered there was a trade-off with this approach – blending datasets could lessen actual changes in the load profile as more customers transition to interval meters and result in a profile that does not fully reflect evolving usage patterns in the short term.

Some retailers also discussed a full transition to interval meter data only. ENGIE noted the AER should consider whether it is appropriate to use interval meter data only considering the Accelerating smart meter deployment rule change.[44] Origin Energy considered blending NSLP and interval meter data in DMO 7 would support a gradual transition to using interval meter data only in DMO 8, by which time the penetration of interval meters is expected to significantly exceed accumulation meters.[45] EnergyAustralia considered using interval meter data only could eliminate the need for further revisions to the load profile methodology.[46]

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42 See more information on compensation awarded from the June 2022 market events from the AEMC.

43 AGL, Submission to DMO 7 draft determination, 7 April 2025, pp. 2–3; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 1; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 1, 3; EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, pp. 2, 4; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

44 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 1.

45 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 1, 3.

46 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, pp. 2, 4.

ENGIE was the only stakeholder to comment on separate load profiles for residential and small business customers. It considered that separate load profiles may be more appropriate for future determinations (as smart meter penetration increases) because it would allow for more accurate forecasting of wholesale costs.[47]

Consumer advocacy groups and government stakeholders did not comment on data used to simulate the load profiles.

Solar PV exports and hedging costs

Exclusion of solar exports from the interval meter dataset

Five small-to-medium sized retailers disagreed with excluding solar exports from the interval meter dataset.[48]

Some retailers considered it would be more appropriate to include solar exports in the load profiles because retailers hedge against net load, and excluding solar exports artificially flattens the load profile.[49] Alinta Energy noted excluding solar exports is inconsistent with AEMO's settlement process for retailers and underestimates hedging.[50]

Other retailers disagreed with the rationale that load shifting measures are available to flatten load, noting challenges faced by smaller retailers that do not have sufficient energy storage capacity or access to significant commercial and industrial customer load to implement these measures. Some retailers also noted that load shifting measures are not yet at scale to offset the impact of solar exports. Separately, ActewAGL considered that load shifting measures are already accounted for in the NSLP and interval meter datasets used to estimate regulated prices.[51]

Powershop/Shell Energy considered benefits from load shifting activities flow through to owners of the consumer energy resources with no guarantee of return for retailers, and costs to retailers for developing or managing these programs should be reflected somewhere in the DMO, particularly since the competition allowance has been removed.[52]

Some retailers also considered the decision to exclude solar exports overlooks the material cost exposure when a retailer is a net exporter during negative price intervals. They also disagreed that adjustments to feed-in tariffs are a sufficient means of managing these instances. They considered adjustments to feed-in tariffs together with orchestration

47 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 2.

48 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, pp. 2–3; Energy Locals, Submission to DMO 7 draft determination, 3 April 2025, p. 1; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 3; ActewAGL, Submission to DMO 7 draft determination, 3 April 2025, pp. 1–3; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, pp. 4–5.

49 Energy Locals, Submission to DMO 7 draft determination, 3 April 2025, p. 1; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 3; ActewAGL, Submission to DMO 7 draft determination, 3 April 2025, pp. 1–3.

50 Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

51 Energy Locals, Submission to DMO 7 draft determination, 3 April 2025, p. 1; ActewAGL, Submission to DMO 7 draft determination, 3 April 2025, pp. 1–3; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, pp. 4–5.

52 Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 5.

measures to mitigate the impact of solar exports assumes a level of influence over customer load profiles that retailers may not necessarily have.[53]

ActewAGL noted the cost of solar exports could be managed to an extent through adjustments to feed-in tariffs in the short term but considered it unsustainable due to the declining value of feed-in tariffs.[54] EnergyAustralia and the Australian Energy Council (AEC) considered that regulators and government should educate customers about solar export pricing and noted that retailers may need to reduce their feed-in tariffs, potentially below zero, to reflect the true market value of solar exports.[55] Additionally, EnergyAustralia noted that without such adjustments retailers may struggle to recover costs, which impacts their ability to offer fair pricing to all customers.[56]

Red Energy and Lumo Energy encouraged the AER to monitor the impact of excluding solar exports from the load profiles. It also noted the approach to exclude solar exports could impact some retailers more, depending on the size and diversity of their customer base.[57]

Consumer advocacy groups continued to support excluding solar exports from the interval meter dataset.[58]

We also received a submission from Jason Page, advocating for higher feed-in tariff values and broader regulatory and policy reform. The submission considered that retailers profit from reselling customers' solar exports to non-solar customers at a higher price than the feed-in tariff they pay to the customer for generating. It also considered that the minimum feed-in tariff should be increased to ensure residential customers receive a fairer share of profits derived from exports and made other policy/regulatory recommendations related to household solar generation, including mandating retailers to disclose profit margins from solar exports.[59]

Hedging costs arising from solar exports

No support was received from stakeholders for the solar hedging adjustment included in the DMO 7 draft determination. Retailers mostly considered the adjustment did not sufficiently

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53 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 3; 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, pp. 2–3; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, pp. 4–5; EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 5.

54 ActewAGL, Submission to DMO 7 draft determination, 3 April 2025, p. 2.

55 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 5; AEC, Submission to DMO 7 draft determination, Australian Energy Council, 8 April 2025, p. 2.

56 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 5.

57 Red Energy and Lumo Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

58 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 4.

59 Jason Page/Residential Supply Generators, Submission to DMO 7 draft determination, 18 March 2025, pp. 1–3.

reflect actual costs faced by retailers, including the cost exposure when exporting to negative price intervals.[60]

Some retailers suggested alternative methods to account for these costs. EnergyAustralia suggested comparing WEC estimates when including and excluding solar exports from the load profiles and respective hedging strategies to observe a larger and more meaningful difference that would reflect the impact of solar exports on hedging strategies.[61] Shell Energy and Powershop considered the AER could determine the average cost retailers incur to serve solar customers in each region and reflect this on a dollar-per-customer basis within the retail component of the DMO cost stack.[62] Other retailers considered changing to the 95th percentile estimate would be an appropriate way to address hedging costs arising from solar exports and mitigate the impact of excluding solar exports from the load profiles.[63]

AGL considered the hedging adjustment was designed to capture observable costs when exporting into negative price intervals and noted the DMO wholesale cost methodology may not have considered this growing cost risk when it was designed. It also noted the lack of transparency in how modelled hedging strategies were determined and why the hedging adjustment resulted in lower wholesale costs for some regions. Finally, it considered adopting the 95th percentile estimate to be appropriate in the absence of an industry accepted cost assessment that meaningfully reflects risks associated with solar exports.[64]

In contrast, consumer advocacy groups did not support any provision for hedging costs arising from solar exports. They considered the adjustment disincentivises retailers to be more efficient in managing risks and provides an allowance for risks retailers may not face in full or risks they should have mitigated for.[65]

The AEC did not support a specific adjustment for hedging costs arising from solar exports. They sought clarification on why solar PV risks need to be assessed separately, noting the hedging strategy within the wholesale cost model would have sufficiently captured these risks. Additionally, they considered any extra costs or benefits associated with solar exports should be factored into how retailers price solar exports, rather than be included in DMO hedging assumptions.[66]

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[60] EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, pp. 2, 4–5; AGL, Submission to DMO 7 draft determination, 7 April 2025, pp. 3–4; 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, pp. 2–3; ActewAGL, Submission to DMO 7 draft determination, 3 April 2025, p. 2; Energy Locals, Submission to DMO 7 draft determination, 3 April 2025, p. 1; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

[61] EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 5.

[62] Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 4.

[63] AGL, Submission to DMO 7 draft determination, 7 April 2025, pp. 3–4; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, pp. 3–4; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 1, 5; 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, p. 3.

[64] AGL, Submission to DMO 7 draft determination, 7 April 2025, pp. 1, 3–4.

[65] JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 4.

[66] AEC, Submission to DMO 7 draft determination, Australian Energy Council, 8 April 2025, p. 2.

5.2.2 Controlled Load Profile (NSW)

There was limited feedback on our decision to maintain use of AEMO's published Controlled Load Profile to simulate controlled load costs in DMO 7. Origin Energy supported our decision to maintain the methodology from prior determinations because it did not consider there had been a significant shift in the load shape in NSW. EnergyAustralia noted it was comfortable with the approach in the draft determination. Both retailers agreed that using AEMO's published Controlled Load Profile is an interim solution requiring future review, with Origin Energy suggesting that it facilitates a smooth transition to exclusively using interval meter data in DMO 8, consistent with their proposed timing for the mass market load profile.[67]

ENGIE opposed the decision to use AEMO's published Controlled Load Profile. ENGIE advocated for blending historical controlled load data with the NSLP because it considered this approach best reflects the basis for settlement and aligns more closely with a prudent retailer's hedging strategy. Although ENGIE noted that blending data presents challenges, particularly in accurately estimating controlled load volume, it contended that this results in a profile that more realistically captures current market conditions by combining controlled load and NSLP data.[68]

5.2.3 South Australian wholesale methodology

All submissions from retailers that commented on the South Australian wholesale methodology supported the approach in the draft determination. Noting the consistency between ASX and OTC data, Alinta Energy supported the continuation of the approach from DMO 6.[69] Origin Energy added that if material misalignment is observed, alternative data sources may need to be considered. It also highlighted the importance of maintaining the use of publicly available data that retailers can typically rely on for the pricing of hedging products.[70] ENGIE, while supportive of the current approach to ensure prudent retailers' hedging costs are reflected, emphasised the analysis should continue only if meaningful value is gained when considering retailer reporting obligations. ENGIE also welcomed the repeat of the LRMC analysis for South Australia if it continues to be a beneficial comparative data point to validate the wholesale cost methodology.[71]

Consumer advocacy groups did not comment on the South Australian wholesale methodology.

5.2.4 Inputs into wholesale modelling

While no specific feedback about variation of wholesale modelling inputs was received, both ENGIE and Origin Energy advocated for a comparison of modelled WEC outcomes from prior determinations with actual spot prices (discussed further in section 5.2.5).

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67 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 3; EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 6.

68 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, pp. 2–3.

69 Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4.

70 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 4–5.

71 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, pp. 3–4.

5.2.5 Other wholesale cost issues

We received no comments on our approach to other wholesale cost modelling assumptions, including our treatment of ASX options, AEMO fees, AEMO prudential requirements and unaccounted for energy.

75th versus 95th percentile

A number of retailers recommended the AER adopt the 95th percentile of modelled cost outcomes because they considered the 75th percentile does not reflect spot market volatility and has the potential to underestimate wholesale costs a prudent retailer may face.[72]

Origin Energy, 1st Energy, ENGIE and AGL suggested that changes being considered to the wholesale cost methodology such as the hedging adjustment for solar exports could be addressed by reverting to the 95th percentile, which would more appropriately reflect the risks faced by retailers.[73] ENGIE also requested the AER conduct a backcast analysis of previous wholesale cost forecasts against actual outcomes to determine whether the 75th percentile is appropriate.[74]

However, the NSW Minister for Energy commented the 75th percentile is arguably conservative from a consumer standpoint and requested the AER consider the 50th percentile as the benchmark and apply a small ‘volatility allowance’ for extreme events.[75]

Length of the book build period

Origin Energy was the only stakeholder to provide feedback on the book build period, stating it supported the existing book build process that occurs over a 2 to 3-year period.[76]

ASX options and other wholesale cost modelling assumptions

Origin Energy agreed that known AEMO and AEMC compensation costs should be passed through the wholesale component of the DMO.[77]

Other responses received from stakeholders

- **Contract price movements:** AGL commented that the small WEC percentage changes in NSW regions (increases between 2.7% and 5.3%) were not consistent with larger increases in relevant ASX contract prices. AGL sought clarification on factors impacting NSW WEC estimates further to changes in contract prices.[78] The South Australian

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72 AGL, Submission to DMO 7 draft determination, 7 April 2025, pp. 1, 3–4; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, pp. 3–4; 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, p. 3; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 1; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 1, 5.

73 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 1, 5; AGL, Submission to DMO 7 draft determination, 7 April 2025, pp. 1, 3–4; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, pp. 3–4; 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, pp. 3–4.

74 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, pp. 3–4.

75 The Hon Penny Sharpe MLC, Minister for Climate Change, Energy, Environment and Heritage, Submission to DMO 7 draft determination, 10 April 2025, p. 1.

76 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 7.

77 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 5.

78 ActewAGL, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

Government noted recent moderations in South Australian contract prices and wanted to ensure these were captured in the relevant trade-weighted contract prices.[79]

- **Performance of the wholesale modelling:** Origin Energy noted that estimated WECs for any determination arising from modelled outcomes will likely be different to actual outcomes. It considered there would be benefits to transparently assessing the performance of the wholesale modelling against actual spot price and demand data. This request was based on Origin Energy's reiteration of its view that the hedging strategy adopted within the modelling does not sufficiently reflect a prudent retailer, noting the high proportion of cap contracts compared with baseload swaps has resulted in more spot price exposure and what it considers a riskier portfolio.[80]

5.3 Final determination

5.3.1 Load profile assumptions

Net System Load Profile and interval meter data

Consistent with the draft determination, we have decided to use one year of NSLP data (October 2023 to October 2024) blended with interval meter data to simulate the load profiles for all regions for DMO 7. As described above, we consider this approach best meets the decision-making factors, including reflection of market outcomes, data transparency and longevity of the decision.

We agree with stakeholder views that this approach best reflects the usage of customers on accumulation and interval meters. We acknowledge EnergyAustralia's views on the trade-off when blending load profiles. However, we consider NSLP data will naturally have less impact on blended load profiles as accumulation meter customers move onto interval meters. We expect a large proportion of small customers in DMO regions to remain on accumulation meters during the DMO 7 period and still consider it important to capture these usage patterns by blending the 2 datasets.

We also acknowledge ENGIE's view on separate load profiles for residential and small business customers in future DMO determinations. While we continue using NSLP data to simulate the load profiles (which cannot be separated into different customer types), we still consider it is appropriate to maintain a single load profile to avoid introducing additional estimation and uncertainty to the wholesale cost methodology.

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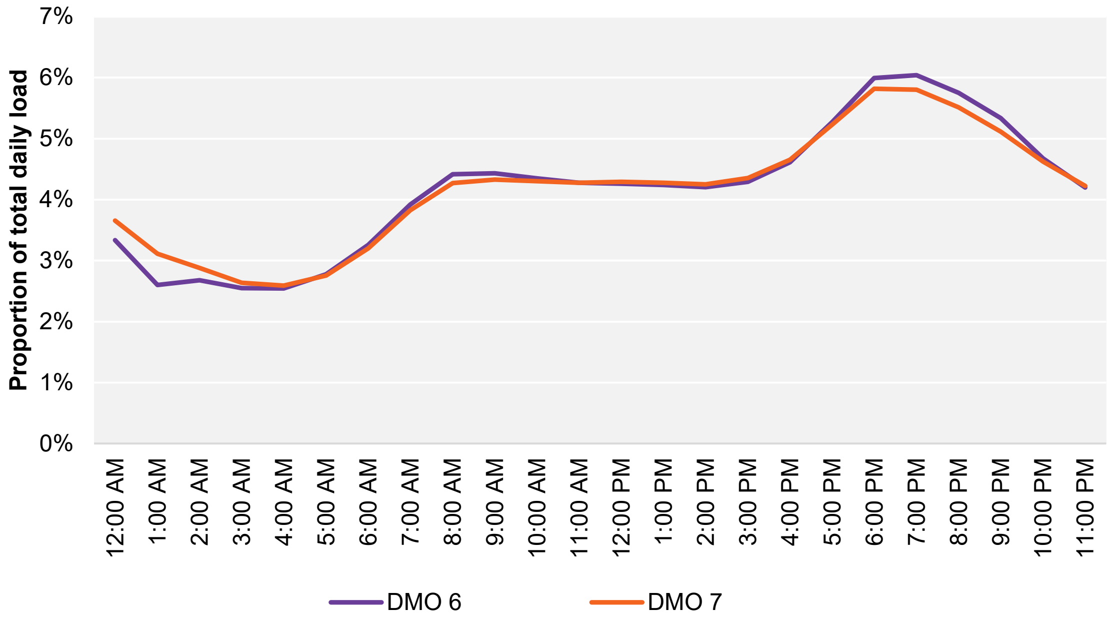
79 South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 3.

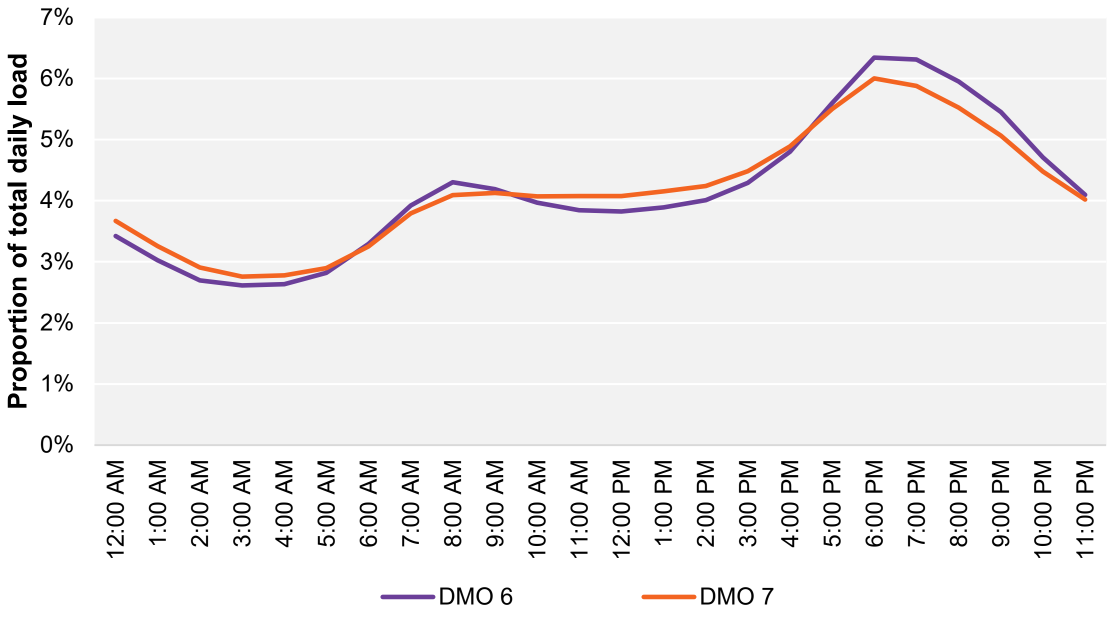
80 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 5.

Figure 5.1 Average time of day load profile, Ausgrid



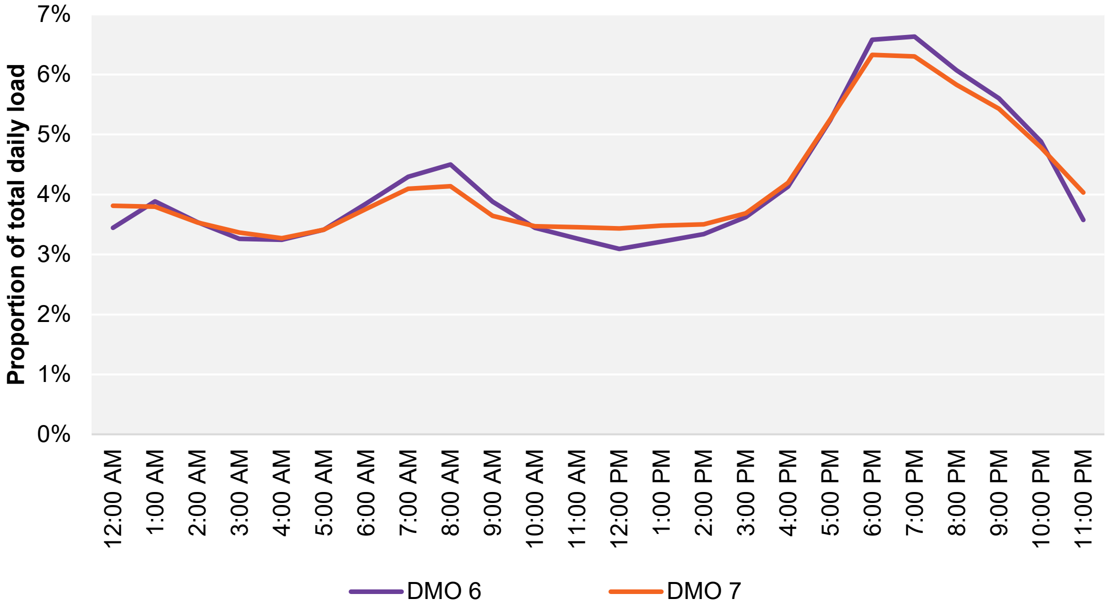
Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.2 Average time of day load profile, Endeavour Energy



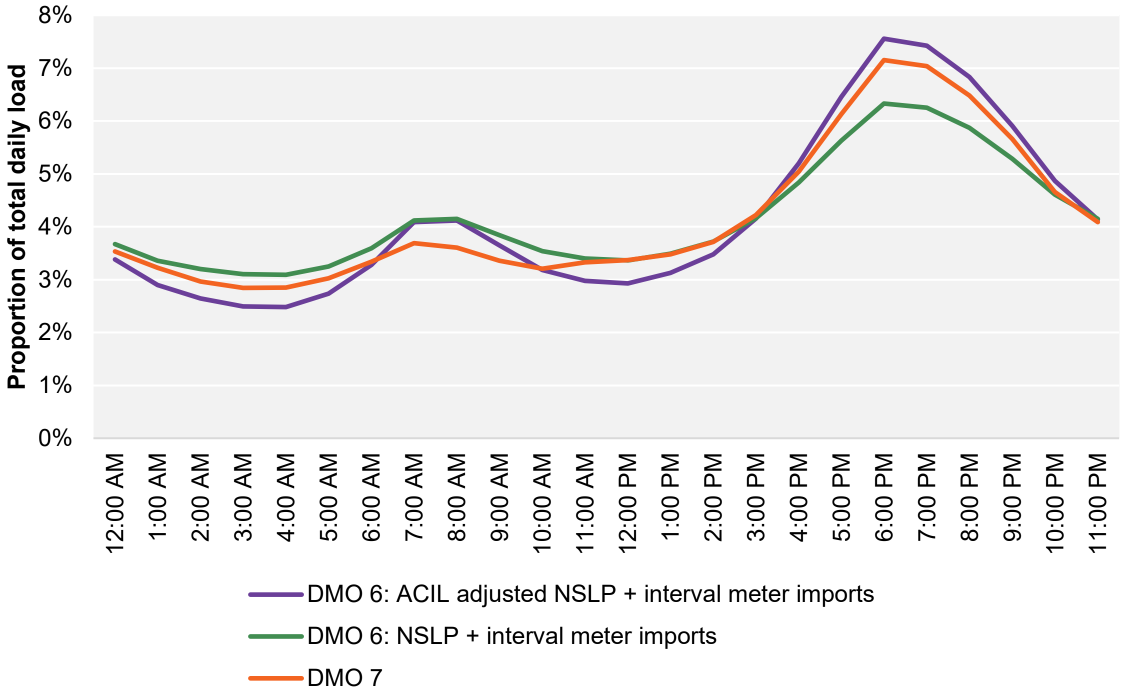
Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.3 Average time of day load profile, Essential Energy



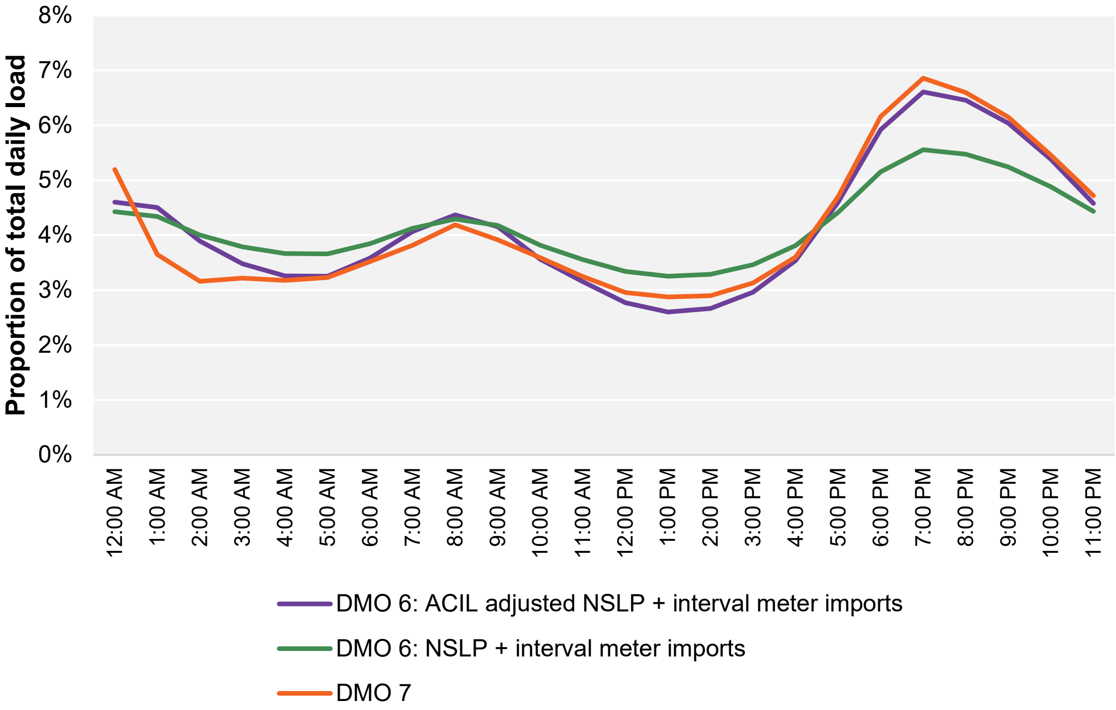
Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.4 Average time of day load profile, Energex



Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.5 Average time of day load profile, SA Power Networks



Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Solar PV exports and hedging costs

We have maintained our approach to exclude solar exports from the interval meter dataset used to simulate the load profiles in the DMO 7 final determination. We have also decided to remove the solar hedging adjustment introduced in the DMO 7 draft determination.

We maintain our view from the draft determination that the DMO is ultimately a tariff for customers' consumption. Therefore, the data used to simulate the load profiles should not include small customers' solar exports.

As we have stated in previous determinations, adding solar exports into the load profiles would result in an overestimation of wholesale costs for a representative prudent retailer (Table 5.1). The materiality of the difference in WEC outcomes highlights that – due to the simplistic nature of the hedging strategy, which is solely based on base and cap contracts – adding solar exports into the load profiles materially increases wholesale costs. We do not consider this is reflective of actual wholesale market outcomes for most retailers.

Table 5.1 Difference in WEC estimates when including solar exports in the load profiles, $/MWh

DMO region	WEC when excluding solar exports	WEC when including solar exports	WEC increase (%)
Ausgrid	$161.07	$178.95	11%
Endeavour Energy	$167.47	$195.42	17%

DMO region	WEC when excluding solar exports	WEC when including solar exports	WEC increase (%)
Essential Energy	$165.17	$193.29	17%
Energex	$150.63	$179.80	19%
SA Power Networks	$168.16	$226.69	35%

Source: WEC estimates were provided by ACIL Allen and are based on DMO 7 final determination numbers.

However, we are aware that some retailers likely face some costs arising from solar exports that may not be accounted for in the wholesale cost methodology. These costs are a result of different hedging strategies used by some retailers which are impacted more by the presence of solar exports than others, through higher hedging costs or the cost exposure when exporting into negative price intervals. However, these hedging strategies also differ from the hedging strategy used within the wholesale cost methodology. The wholesale cost methodology hedging strategy is purposefully transparent, simplistic and based on publicly available data. We consider this approach ensures stability in the methodology and is reasonable in forecasting wholesale costs that are included in DMO prices.

We do not consider it reasonable to try to reflect all potential hedging costs and strategies that are adopted by retailers that differ from the wholesale cost methodology, because these costs would ultimately be passed on to consumers.

We also maintain the view that retailers continue to have alternative strategies and customer and supply-side portfolio benefits available to flatten loads and mitigate the impact of solar exports in practice. This could include adjustments to feed-in tariffs, hot water and electric vehicle charging orchestration, demand management programs and other solar soaking strategies, generation and large-scale batteries, and consumer and industrial customer load. However, we do not consider the wholesale cost methodology can comprehensively account for these measures and the varying extents to which they are being used by retailers.

The solar hedging adjustment introduced in the draft determination was an attempt to recognise how the wholesale cost methodology could reflect the change in a retailer's hedging product mix and costs when considering the presence of solar exports. However, no stakeholders supported the inclusion of this adjustment or considered it to be an adequate reflection of costs faced in practice. As a result, we have decided to remove the adjustment in the DMO 7 final determination. We acknowledge alternatives suggested by some retailers but consider calculating the difference in WECs when including solar exports in the load profiles and modelled hedging strategy would have the same result as including solar exports in the load profiles, which we consider would result in an overestimation of wholesale costs. We also note that estimating the average cost retailers incur to serve solar customers in a region would likely require consideration of the cost of feed-in tariffs paid by retailers, which we must disregard according to the DMO Regulations.[81]

The removal of the adjustment combined with excluding solar exports from the load profiles could risk not recognising costs faced by some retailers. We consider that maintaining the

81 Regulations, s. 8A.

75th percentile estimate instead of adopting the 50th is one way that ameliorates the potential for understating costs, without shifting the balance of risk too far onto consumers – which we consider the 95th percentile would do. However, in DMO 8 we will engage further on alternative ways to recognise costs arising from solar exports, while avoiding an over-recovery of costs from consumers that would occur if solar exports were included in the load profiles.

We acknowledge Jason Page's submission, which advocated for higher feed-in tariffs. However, we must disregard feed-in tariffs paid by retailers when setting DMO prices as per the DMO Regulations. Further, the DMO framework (including the DMO Regulations and policy objectives) does not allow for or require the AER to establish a minimum regulated feed-in tariff.[82]

5.3.2 Controlled Load Profile (NSW)

We have decided to maintain our approach of using AEMO's historical Controlled Load Profile to simulate the controlled load profiles in NSW.

We consider that this approach accurately reflects the shape of controlled load demand in NSW, as evidenced by the similarity of the published Controlled Load Profile with more recent interval meter controlled load profiles provided by the NSW distribution businesses. We acknowledge the concerns of ENGIE that this approach will not reflect settlement of accumulation meter controlled load customers during the DMO 7 period (which will occur against the NSLP), but consider that attempts to replicate settlement drastically overstate hedging costs due to the unrealistic shape of the resulting profiles, largely driven by the substantially higher volumes of the NSLP dataset.

We are aware that this approach will need to be reconsidered in DMO 8, given that AEMO's published NSW Controlled Load Profile will have become outdated. Additionally, we consider interval meter controlled load should be reflected when estimating a wholesale cost for controlled load, given that this may diverge from the accumulation meter demand shape in the near future. For stakeholder consultation through the DMO 8 issues paper, we intend to engage with AEMO and distribution businesses before the standard consultation period to further explore available methods for estimating controlled load costs.

5.3.3 South Australian wholesale methodology

For the DMO 7 final determination, we decided to maintain our approach of using only ASX data for relevant base futures, cap contracts and premiums for call options as we continue to observe alignment between ASX and OTC data.

The collected confidential OTC contract information relevant to the DMO 7 period showed relevant OTC trades are still 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 the region.

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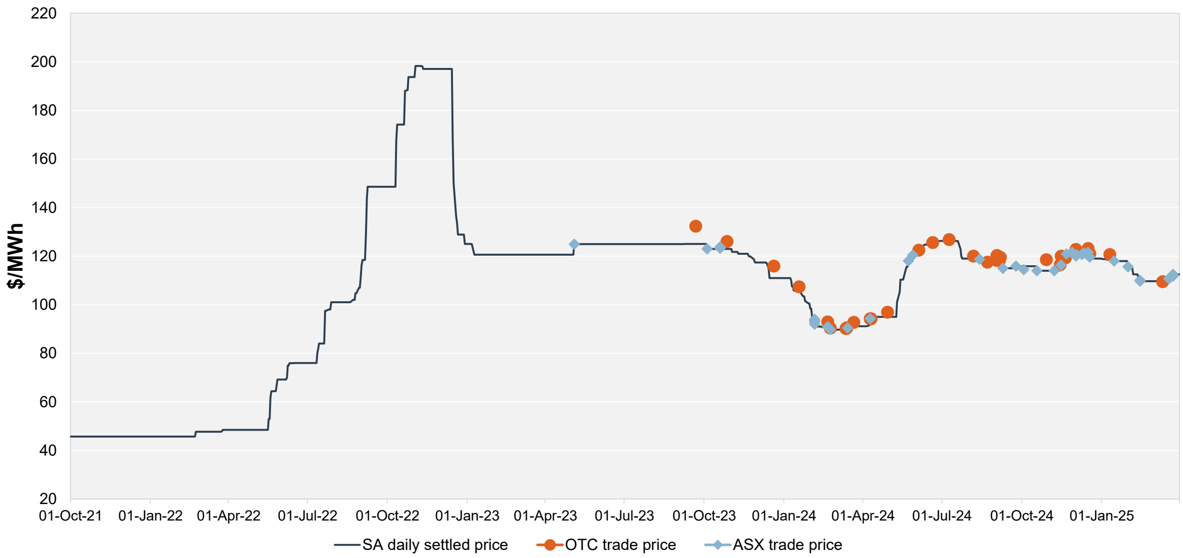
82 Regulations, s. 8A.

Figure 5.6 OTC and ASX price alignment, base futures, Q3 2025



Note: Analysis was completed for all quarters
Source: AER analysis using ASX, OTC data.

The WEC for the DMO 7 final determination sits between the greenfield (modelling builds out generation to meet supply at least cost) and brownfield (modelling based on current generation fleet) approach of the LRMC results, with greenfield having the highest estimate followed by the DMO 7 WEC estimate. The analysis repeated from DMO 6, despite changes in inputs, produced similar results in the direction of cost changes, which highlights that this is a valid additional data source to compare wholesale costs for South Australia.

The LRMC analysis, in conjunction with OTC data, serves as a useful comparative data point to assess wholesale costs in the region. We have retained our current methodology and will continue to use additional information and data to ensure our wholesale costs remain appropriate, considering the low levels of liquidity in the South Australian contract market.

5.3.4 Inputs into wholesale modelling

We have decided to maintain the existing array of fuel price inputs into the wholesale model to avoid introducing additional complexity and subjectivity into the wholesale model.

As discussed further in section 5.3.6, we will consider the performance of the wholesale model before we begin consultation for DMO 8.

5.3.5 Other wholesale cost issues

We have made the following decisions on other wholesale cost methodology issues for the DMO 7 final determination.

75th versus 95th percentile

We have maintained our approach of using the 75th percentile of modelled wholesale cost outcomes. We consider this strikes the right balance between retailers recovering efficient costs for providing their services and the allocation of risks to consumers. We do not consider a change to the 95th percentile should be adopted in response to other issues consulted on, such as hedging costs arising from solar exports. We consider it more appropriate to consider these aspects of the methodology individually rather than select a higher percentile estimate of modelled wholesale costs that would reflect nearly all potential market outcomes and could lead to an overstatement of wholesale costs.

We also do not consider a change to the 50th percentile is appropriate. While the 50th percentile would represent an even sharing of risk between retailers and consumers, we consider the 75th percentile estimate remains most appropriate when taking into account factors we must consider under the DMO Regulations. This includes determining a reasonable per-customer annual price for supplying electricity in a region, the principle that a retailer should be able to make a reasonable profit, and having regard to the wholesale cost of electricity in DMO regions.[83] Additionally, we consider that the DMO is not an efficient price, and adopting the 75th percentile estimate better enables retailers to recover their efficient costs and make a reasonable profit.

Treatment of compensation costs

Further to the compensation awarded to Origin Energy and EnergyAustralia Ecogen in September 2024 for the June 2022 market events, the DMO 7 final determination now reflects compensation awarded to Snowy Hydro in May 2024, which was overlooked in the preparation of the draft determination.[84]

These claims have been portioned and allocated within wholesale costs based on generation volume and location of the affected generators. Impacts on generators in Victoria have been excluded because the DMO does not apply in Victoria, and we do not consider it appropriate for these costs to be recovered from customers in DMO regions.

Other aspects of the wholesale methodology

We have decided to maintain our approach for other aspects of the wholesale cost methodology, including the length of the book build period, treatment of ASX options and treatment of AEMO fees and prudential requirements. These aspects were either supported by stakeholders or received no responses.

5.3.6 Responses to other stakeholder feedback

This section outlines our considerations and responses regarding issues raised in submissions that were not directly consulted on in the draft determination.

- **Contract price movements:** We acknowledge AGL's view that increases in NSW WECs between DMO 6 and DMO 7 are less than the increase observed in contract prices in percentage terms. We note that WECs do not move in exact alignment with contract prices and movements in WECs reflect a variety of factors, including modelled spot prices and relative price movements in cap and base futures prices coupled with changes in load profiles and the modelled hedging strategy. A slightly higher reliance on base futures and lower reliance on caps in DMO 7 for NSW regions is one factor that has resulted in the strong increases observed in cap contract prices not directly flowing through into WEC estimates in NSW. There has also been a slight change to the load profile shape across NSW distribution regions, which has also impacted WEC

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83 Regulations, s.16(1)(b), (4)(b) and (4)(c)(i).

84 See more information on compensation awarded from the June 2022 market events from the AEMC.

estimates.[85] Overall, we consider long-term trends observed in WECs and contract prices have remained broadly aligned.

- **Performance of the wholesale modelling:** We will consider a comparison of modelled WEC outcomes from prior determinations with actual outcomes, as suggested by Origin Energy and ENGIE, prior to release of the DMO 8 issues paper.

5.4 Wholesale costs

Wholesale energy costs have increased across almost all regions and customer types. While the scale of increases varies across regions, all are primarily due to rising contract and spot market prices. Changes in the shape of load profiles have also had an impact. In South Australia a peakier load shape has partially driven increases in cost, while in NSW and SE Queensland, flatter load shapes have partially offset cost increases driven by contract prices.

Movements in base futures and cap contract prices, compared with DMO 6, on an annualised and trade-weighted basis are:

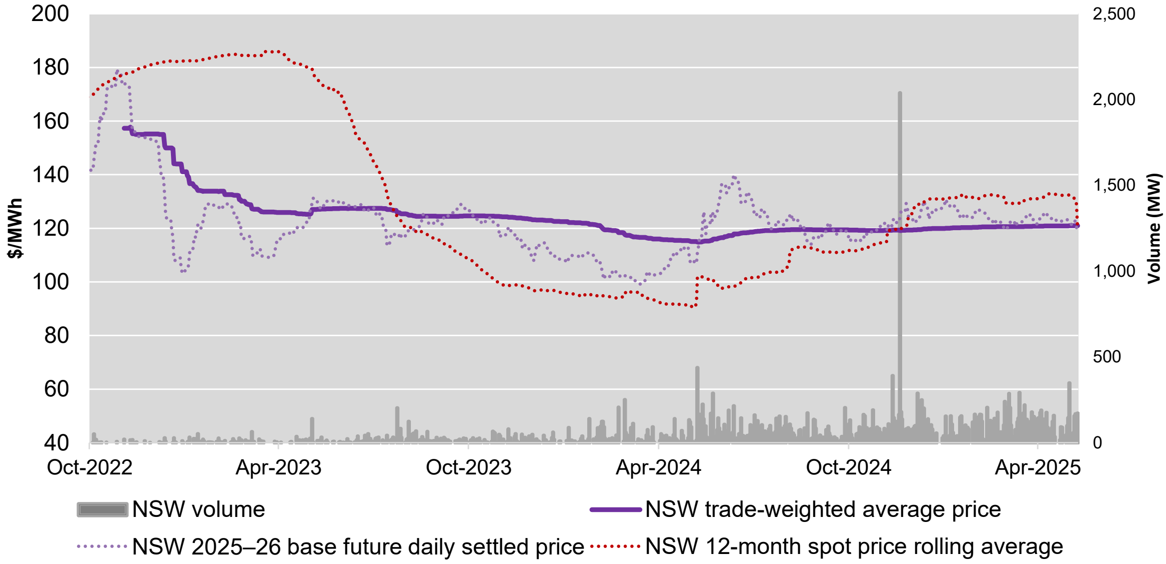
- for NSW – an increase of base futures contract prices of $8.80/MWh and an increase of cap contracts of $7.40/MWh
- for Queensland – an increase of base futures contract prices of $4.60/MWh and an increase of cap contracts of $0.40/MWh
- for South Australia – an increase of base futures contract prices of $2.40/MWh and an increase of cap contracts of $2.90/MWh.

Contracts relevant to DMO 7 saw limited trade during the record high prices observed in 2022. As such, these prices have had limited impact on DMO 7 trade-weighted averages. However, after moderating throughout 2023, contract prices increased again in 2024, with particularly strong increases observed in May 2024. This coincided with the market events that resulted in suspension of the NSW spot market. Since that time, contract prices have fluctuated but remained at elevated levels, likely influenced by abnormally frequent high spot price events in late 2024, maintaining the presence of a risk premium in contract prices. Despite lower spot prices in the first quarter of 2025, the presence of this risk premium appears to have held base futures prices at roughly the same level as they ended in 2024, except in South Australia where prices have fallen modestly.

For most regions, the largest volume of trade was observed in the latter half of 2024 and early 2025. This has resulted in higher contract prices at that time having a greater impact on trade-weighted average prices than the lower prices throughout 2023. While Queensland saw significant traded volumes at lower prices during 2023, this has been offset by significant traded volume at higher prices in late 2024 and early 2025.

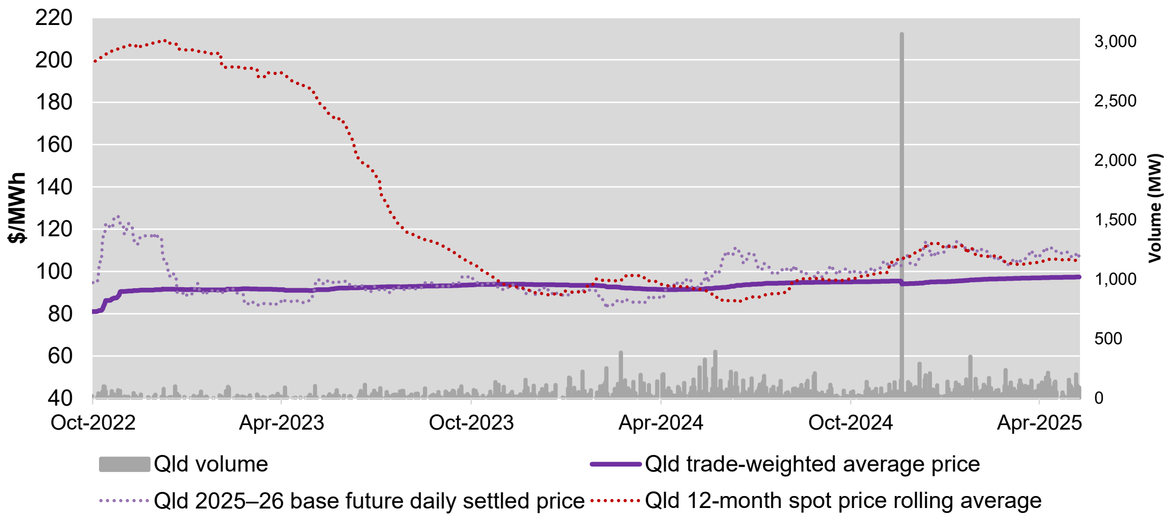
85 ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Final Determination*, 26 May 2025, pp. 37–38.

Figure 5.7 NSW base future daily settled price and trade-weighted average, 2025–26



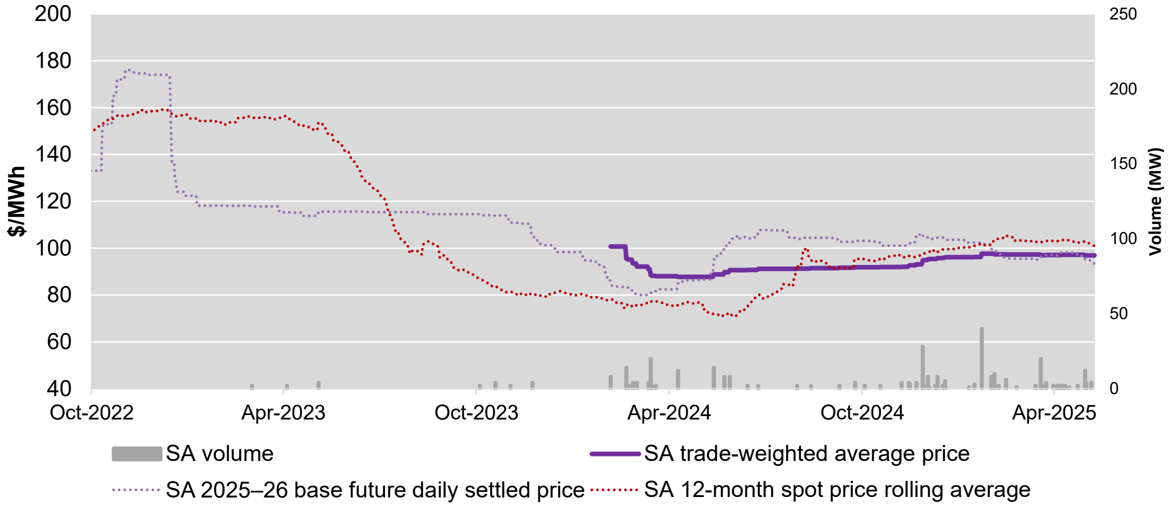
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 5.8 Queensland base future daily settled price and trade-weighted average, 2025–26



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

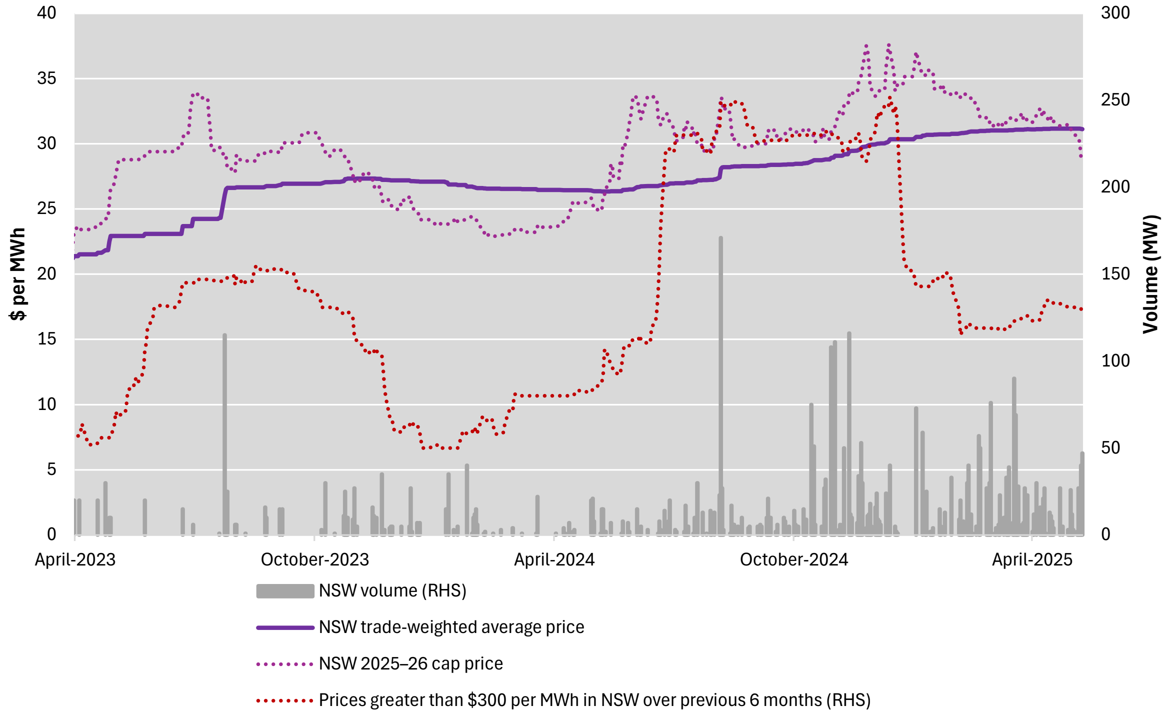
Figure 5.9 South Australia base future daily settled price and trade-weighted average, 2025–26



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year. For South Australia, a trade-weighted average price was not available until early 2024 because volume had not been traded for all quarters before that time.
Source: AER analysis using ASX, AEMO data.

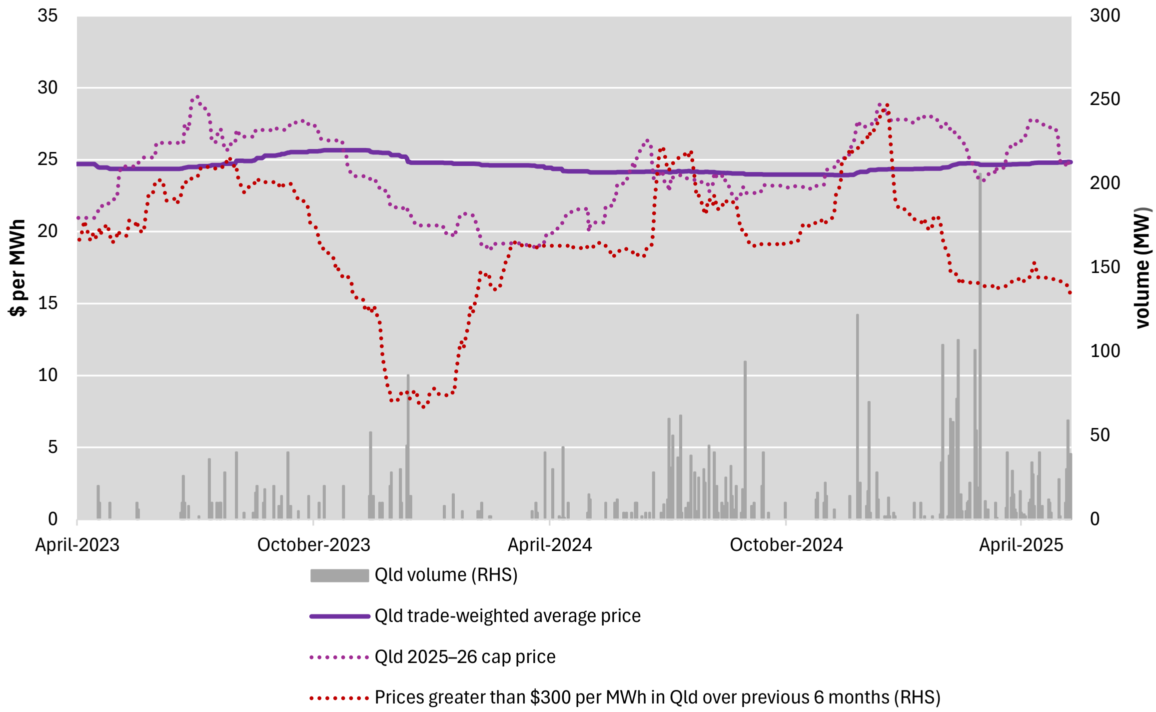
Cap contracts followed roughly the same pattern as base futures in terms of price movements and traded volume until the start of 2025. Since then, they have recorded a substantial price decline, potentially resulting from a decrease in incidence of spot prices above $300/MWh in the wholesale spot market. Notably, the price of cap premiums remains substantially elevated compared with previous years. The volume of DMO 7 relevant cap contracts traded at lower prices in early 2025 was only a fraction of the volume traded during the higher priced 2024. Accordingly, the decreases have had little impact on the trade-weighted average cap prices used in this determination.

Figure 5.10 NSW cap premiums daily settled price and trade-weighted average, 2025–26



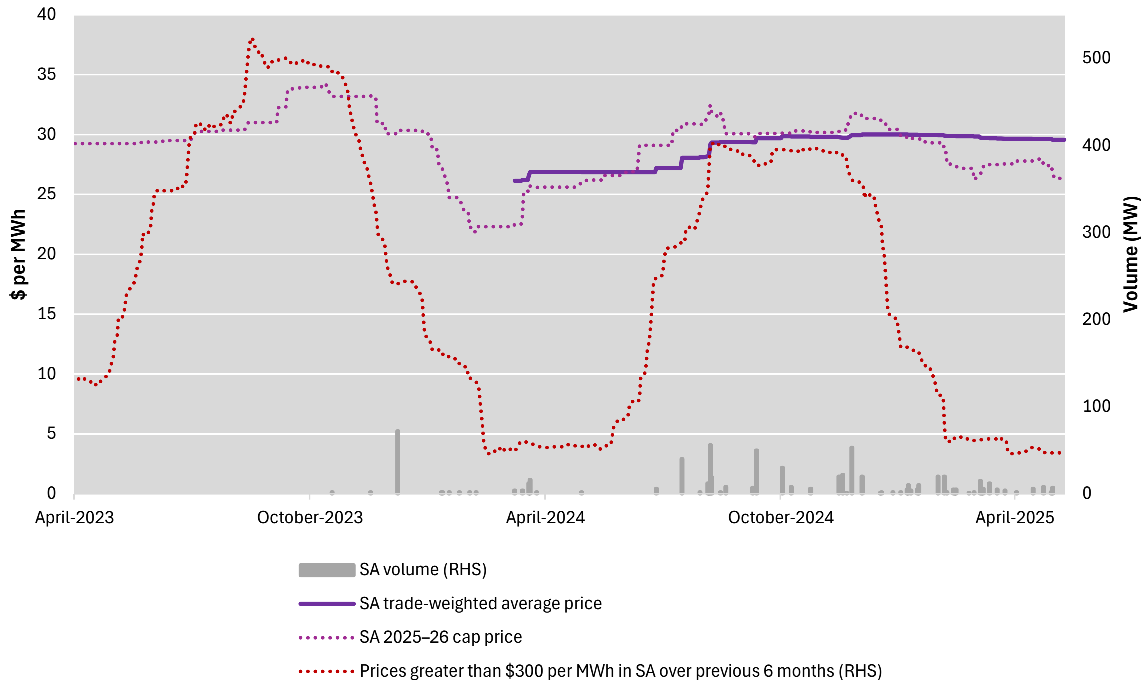
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 5.11 Queensland cap premiums daily settled price and trade-weighted average, 2025–26



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 5.12 South Australia cap premiums daily settled price and trade-weighted average, 2025–26



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year. For South Australia, a trade-weighted average price was not available until early 2024 because volume had not been traded for all quarters before that time.
Source: AER analysis using ASX, AEMO data.

Components of wholesale costs that are calculated separately from the WEC have also contributed to total cost movements from DMO 6 to DMO 7. Costs of network losses fell in both SA Power Networks and Energex regions. In Energex the decrease in network losses offset smaller increases in other parts of the wholesale cost. South Australia saw a notable decrease in directions for system security, which combined with falling network losses to partially offset the increase observed in the WEC. Conversely, network losses increased in NSW regions, while only minor changes in other wholesale cost components occurred.

Final wholesale costs for DMO 7 are set in Table 5.2 and compared with costs included in DMO 6 (2024–25).

Table 5.2 Wholesale costs for 2025–26 DMO 7 final determination, $/MWh (variable costs, excl. GST, nominal)

Distribution region	Customer type	2024–25 (final)	2025–26 (final)	Change year-on-year
Ausgrid	Flat rate	$162.99	$172.20	5.7%
	CL 1	$106.85	$124.58	16.6%
	CL 2	$106.70	$122.71	15.0%

Distribution region	Customer type	2024–25 (final)	2025–26 (final)	Change year-on-year
Endeavour Energy	Flat rate	$173.70	$182.42	5.0%
	CL 1	$108.20	$130.29	20.4%
	CL 2	$108.20	$130.29	20.4%
Essential Energy	Flat rate	$163.18	$175.54	7.6%
	CL 1	$104.52	$123.89	18.5%
	CL 2	$104.52	$123.89	18.5%
Energex	Flat rate	$164.97	$164.39	-0.4%
	CL 1	$104.17	$113.10	8.6%
	CL 2	$112.60	$119.95	6.5%
SA Power Networks	Flat rate	$180.15	$191.72	6.4%
	CL 1	$114.46	$120.19	5.0%

Note: CL refers to controlled load.
Source: ACIL Allen and AER Default market offer 2025–26 cost assessment model.

6 Environmental costs

- For the DMO 7 final determination we have decided to retain our existing market-based approach to environmental cost forecasting.
- Environmental costs make up between 3% to 4% of the DMO 7 prices.
- Environmental costs have decreased since DMO 6 across all distribution regions, customer types and tariff structures by between 18.1% and 27.9%.

Environmental schemes, at the national level and in some states, require retailers to procure energy from renewable sources. The costs of complying with these schemes is incurred by retailers. The Regulations require us to consider all costs associated with complying with federal and state/territory laws when determining a DMO price.[86] Thus, an environmental cost category makes up part of the DMO.

In the DMO, environmental costs fall into 3 categories:

Large-scale Renewable Energy Target (LRET)
The LRET encourages investment in the development of renewable energy power stations, like wind and solar farms, by providing a financial inventive for electricity generated from renewable sources.

Small-scale Renewable Energy Scheme (SRES)
The SRES encourages investment in small-scale renewable energy. It provides incentives to households and businesses to install small-scale renewable energy systems like rooftop solar, solar water heaters and air sourced heat pumps.

Jurisdictional green schemes
Include state policies encouraging improving energy efficiency for households and businesses and financial incentives to reduce consumption at times of peak demand. These schemes are funded by retailers and provide consumers discounts or rebates on energy-saving products such as efficient lighting.

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

Most environmental costs are incurred through complying with the Renewable Energy Target (RET) administered by the Clean Energy Regulator (CER). The RET aims to reduce greenhouse gas emissions and increase renewable energy usage in the energy sector.[87] Retailers have an obligation to purchase renewable energy certificates and surrender them to the CER based on the percentage of energy purchased through renewable sources.[88]

The RET is made up of 2 schemes – the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). LRET costs are incurred by retailers to acquire the necessary amount of Large-scale Generation Certificates to promote long-term investment in renewable energy infrastructure.[89] Similarly, SRES costs are incurred by retailers to acquire the necessary amount of Small-scale Technology Certificates to support small-scall renewable energy infrastructure.[90]

There are also jurisdiction-based schemes specific to NSW and South Australia. In NSW, these are the Energy Savings Scheme and Peak Demand Reduction Scheme. The Energy Savings Scheme is a government program that provides financial incentives to install energy-efficient equipment and appliances through retailers being obligated to purchase and surrender state government issued Energy Savings Certificates.[91] The Peak Demand Reduction Scheme is a program that encourages households and businesses to reduce energy consumption during peak demand periods.[92] In South Australia, the Retailer Productivity Scheme is an initiative that establishes annual productivity targets for retailers set by the South Australian Minister and administered by the Essential Services Commission of South Australia.[93] [94] Retailers satisfy these targets through being obligated to provide incentives to households and small businesses in the form of productivity activities.[95]

6.1 Draft determination

In our issues paper and draft determination, we proposed to maintain our market-based approach to calculating environmental costs on the basis that it remains reflective of environmental costs incurred by a retailer.

6.2 Stakeholder views

We received a small number of submissions that discussed environmental costs, with 3 submissions received from retailers and one joint submission received from various consumer advocacy groups.

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87 CER, Renewable Energy Target, Clean Energy Regulator.

88 DCCEEW, Renewable Energy Target scheme, Department of Climate Change, Energy, the Environment and Water.

89 CER, Large-scale Renewable Energy Target, Clean Energy Regulator.

90 CER, Small-scale Renewable Energy Scheme, Clean Energy Regulator; CER, Small-scale technology certificates, Clean Energy Regulator.

91 NSW Government, Energy Savings Scheme.

92 NSW Government, Peak Demand Reduction Scheme.

93 Government of South Australia, Retailer Energy Productivity Scheme.

94 Essential Services Commission of South Australia, Retailer Energy Productivity Scheme.

95 Essential Services Commission of South Australia, Obliged retailers and activity providers.

Most of these submissions supported the existing market-based approach to calculating environmental costs. Retailers considered the inclusion of environmental costs reflects the actual costs incurred by a retailer and that ACIL Allen's methodology for calculating LRET, SRES and jurisdiction-specific costs remains sound.[96]

Powershop/Shell Energy's submission highlighted the approach accurately reflects the costs associated with Australian Government renewable energy schemes and the market prices for certificates. The submission also stated that these costs are a legitimate cost to retailers, so should be included in the cost stack.[97]

The submissions by both Origin Energy and Alinta Energy agreed with the current approach.[98] Alinta Energy's submission suggested the AER monitor the outcomes of the National Electricity Market Wholesale Market Settings Review to understand if any changes need to be made to the sub-components of environmental costs.

The joint submission made by JEC/ACOSS/SACOSS/QCOSS acknowledged that changes to how environmental costs are recovered is not within the scope of the DMO. However, the submission contended the inclusion of environmental costs impacts the objectives of the DMO, specifically the objective of protecting customers from unreasonably high prices.[99] The joint submission supported the AER, in its capacity as a regulator, to recommend the Energy and Climate Change Ministerial Council review the cost recovery of environmental and efficiency schemes to implement more equitable cost recovery.[100] This recommendation suggested removing exclusions for large-scale users and transmission connected entities and/or removing these costs from customer bills and recovering them through government budgets.[101] The joint submission also recommended the AER consider how environmental costs can be removed from the cost stack and instead be recovered through government revenue or taxation to protect vulnerable consumers.[102]

6.3 Final determination

We agree with JEC/ACOSS/SACOSS/QCOSS's position that there is limited scope to change environmental costs.[103] As it is a requirement within the DMO Regulations for us to consider the costs of complying with Australian Government and jurisdictional environmental schemes, our determination includes these in the DMO cost stack.[104]

Based on stakeholder submissions received and stakeholder consultation, we have determined that retaining our existing market-based approach to forecasting environmental

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96 Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 8; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 5.

97 Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 5.

98 Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 8.

99 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 7.

100 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 7.

101 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, pp. 7–8.

102 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 11.

103 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 7.

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

costs with updates for new and amended schemes remains the most appropriate to calculate environmental costs. This existing approach is an accurate representation of the costs a prudent efficient retailer incurs to comply with Australian Government and jurisdictional environmental schemes, and is supported by stakeholder feedback and modelling conducted by ACIL Allen.[105]

6.3.1 Environmental cost inputs

The environmental cost inputs for DMO 7 are shown in Table 6.1, together with inputs used for comparison with DMO 6. Decreases in costs associated with Australian Government RET schemes drove decreases in all regions. Decreases in South Australian renewable energy target scheme costs further contributed to the decreases in South Australia. An increase in costs associated with one of the NSW renewable energy target schemes slightly offset the decreases in NSW.

Table 6.1 Environmental costs for 2024–25 and 2025–26 (excl. GST, nominal)

Distribution region	Tariff	2024–25 $/MWh	2025–26 $/MWh	Change year-on-year (%)
Ausgrid	Flat rate	$19.64	$15.93	-18.9%
	CL 1	$19.75	$15.93	-19.4%
	CL 2	$19.75	$15.93	-19.4%
Endeavour Energy	Flat rate	$19.81	$16.22	-18.1%
	CL 1	$19.81	$16.22	-18.1%
	CL 2	$19.81	$16.22	-18.1%
Essential Energy	Flat rate	$19.34	$15.84	-18.1%
	CL 1	$19.34	$15.84	-18.1%
	CL 2	$19.34	$15.84	-18.1%
Energex	Flat rate	$16.53	$11.92	-27.9%
	CL 1	$16.53	$11.92	-27.9%
	CL 2	$16.53	$11.92	-27.9%
SA Power Networks	Flat rate	$22.16	$16.42	-25.9%
	CL 1	$22.16	$16.42	-25.9%

Note: CL refers to controlled load.
Source: ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Final Determination*.

105 ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Final Determination*, 26 May 2025, p. 79–84; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 8; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 5.

7 Retail costs

For the DMO 7 final determination, we have:

- sought further information from retailers on reported retailer cost data and excluded specific cost items from the retail and other cost component, including fines and financial penalties
- maintained the customer-weighted average approach to quantify retail and other costs and bad and doubtful debt
- continued to base the smart meter allowance on actual installations and a cost of capital allowance to cover the projected shortfall in the smart meter allowance.

Retail costs represent between 6% and 16% of the DMO 7 prices, increasing by 8.3% to 35.4% since DMO 6.

The Regulations direct the AER, in determining what it considers to be a reasonable per customer annual price for supplying electricity, to have regard to retail costs.[106] Retail costs reflect a range of costs incurred by retailer, including:

Costs to serve
such as costs for billing, call centres and hardship programs. We estimate costs to serve using retail cost data obtained through information requests, which we escalate by CPI to the end of the DMO year.

Costs to acquire & retain customers
such as advertising campaigns to inform new customers of their options, rights and obligations. We estimate such costs from retail cost data collected through information requests. We escalate these by CPI to the end of the DMO year.

Bad & doubtful debt
retailers set aside revenue to cover instances where customers cannot repay their debt. We use bad and doubtful debt data from our retail cost data.

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

106 Costs to serve and costs to acquire and retain customers are explicitly listed in the Regulations, s. 16(4)(c)(iv)–(v).

For the DMO 7 final determination, the retailer cost data we collected included:

- retailer-reported information to quantify retail and other costs, as well as bad and doubtful debt
- smart meter data from retailers selling to approximately 94% of small customers across all DMO regions on their rollout of smart meters.

All retail cost calculations, which are based on 2023–24 data, have been escalated by the inflation forecast to occur to the end of the DMO 7 year. The RBA has forecast 2.4% inflation in 2024–25 and 3.2% inflation for 2025–26. This amounts to 5.7% inflation.[107]

7.1 Draft determination

7.1.1 Retail and other costs

As outlined in our DMO 7 issues paper and draft determination, we collected retailer cost data from a cohort of 26 retailers and sought stakeholder feedback on our approach to estimating these costs.[108] In the draft determination, we proposed to set the benchmark for retail and other costs based on the customer-weighted average across all cost components, including retailers' costs to serve, costs to acquire and retain, and other retail costs. This approach resulted in a value for retail and other costs that would enable retailers selling to 77% of residential customers and 70% of small businesses in DMO regions to fully recover their costs.

We explored several alternative statistical approaches to quantify these costs, including the mean, median and percentiles. However, we found that the customer-weighted average provides a more reliable and stable benchmark because it is less susceptible to fluctuations in retailers' cost data. Additionally, we considered this approach achieves the most appropriate balance between allowing a retailer to earn a profit, while also setting a reasonable price for consumers.

Figure 7.1 illustrates the spread of retail and other costs for the 'Big 3', 'Non–Big 3' and 'New retailers for DMO 7' cohorts.[109] It highlights a considerable variation in costs among these cohorts across residential and small business customers. We consider applying a customer-weighted average strikes the most appropriate balance of the competing consumer protections and competition objectives.

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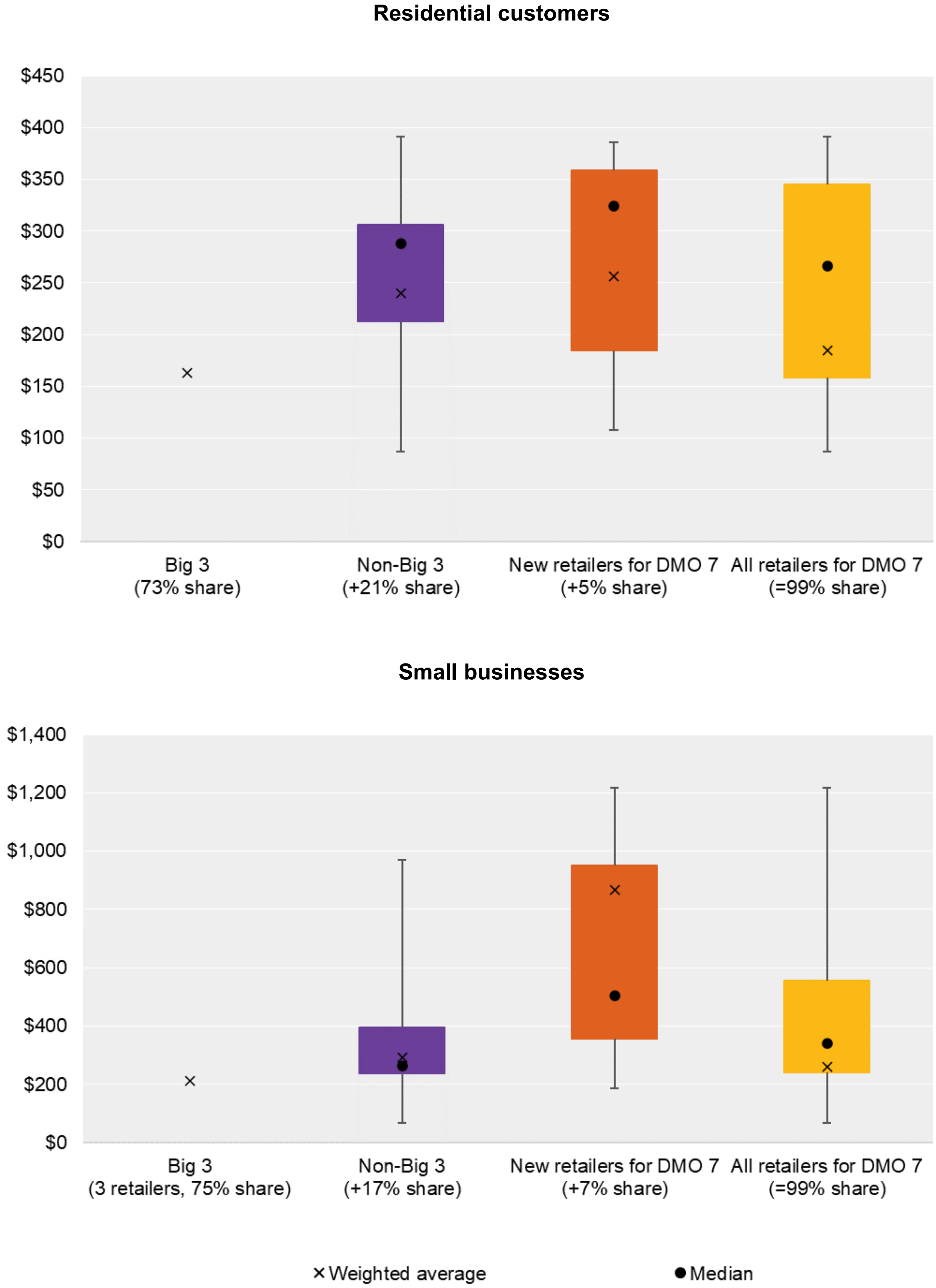
107 RBA, February 2025 Statement on Monetary Policy, Table 3.1 Detailed forecast information, Reserve Bank of Australia.

108 Our retailer cost data includes the same retailers that provided retail cost information to the ACCC for their *Inquiry into the NEM December 2024 report*. The additional retailers we have collected have at least 1,000 small customers across the DMO regions (NSW, SE Queensland and South Australia). The data provided relates to the 2023–24 year.

109 Big 3 retailers are AGL, EnergyAustralia and Origin Energy. Non–Big 3 retailers include those covered by the ACCC's information request for their December 2024 Inquiry report (10 retailers). Our dataset captures retail cost information from both the Big 3 and non–Big 3 groups, as well as 13 small retailers that have not previously provided cost information before DMO 7 ('New retailers for DMO 7'). A total of 26 retailers are captured in our own information request. We excluded the minimum, maximum and interquartile ranges for the Big 3 retailers for confidentiality reasons. Only weighted averages are shown due to their small sample size.

Figure 7.1 Distribution of retail and other costs ($/customer), by customer type, all DMO regions, inc. GST



Note: These figures have been updated from the DMO 7 draft determination and reflect the removal of excluded costs and outliers.
Source: AER analysis of retail cost information.

As noted in our DMO 7 draft determination, we intend to continue collecting retailer cost data from retailers for future DMO determinations to ensure the benchmark reflects the most up-to-date cost information available.

7.1.2 Bad and doubtful debt

Bad and doubtful debts represent costs retailers incur when writing off unpaid bills. We consider bad and doubtful debt costs to be a relevant matter that we must have regard to.[110] A retailer's debt is made up of:

- payments owed for electricity supplied but not yet billed
- customer debt awaiting payment
- an estimated provision for customer debt (based on a retailer's subjective assessment of expected non-payment).

We decided to apply the customer-weighted average to the bad and doubtful debt data collected from our retail cost information request, which we consider is a broader and more representative sample than data previously sourced from the ACCC's Inquiry into the NEM reports.

In the DMO 7 draft determination, we stated that we will further consider actual bad and doubtful debt in future DMO determinations.

7.1.3 Smart metering costs

Smart meter costs are the annual costs retailers incur for smart meters and include costs associated with installation, maintenance and IT. Based on responses to our information requests, we understand that very few retailers separately charge smart meter installation fees. We also note that the AEMC accelerating smart meter deployment rule change prohibits retailers charging up-front fees when a smart meter is installed as part of the legacy meter replacement plan, which commences on 1 December 2025.[111] We consider smart meter costs to be a relevant matter that we must have regard to.[112] As smart meters are progressively installed in DMO regions, smart meter costs also increase across the DMO period, which results in a shortfall in the smart meter allowance in the DMO price.

In the DMO 7 draft determination we proposed to continue the approach of basing the smart meter costs and allowance on actual installations, as at 30 September 2024 (draft determination) and 31 March 2025 (final determination), until legacy meter replacement plans are in place.[113]

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110 Regulations, s 16(4)(d).

111 See the AEMC's rule determination for the Accelerating smart meter deployment rule change for more information on smart meter up-front fees. AEMC, Accelerating smart meter deployment, Rule determination, Australian Energy Market Commission, 28 November 2024, pp. 26–27.

112 Regulations, s 16(4)(d).

113 See the AEMC's rule determination for the Accelerating smart meter deployment rule change for more information on legacy meter replacement plans. AEMC, Accelerating smart meter deployment, Rule determination, Australian Energy Market Commission, 28 November 2024, pp. 10–19.

7.2 Stakeholder views

Eleven stakeholders submitted feedback on issues relating to retail costs and smart meters.

7.2.1 Retail and other costs

Most stakeholders supported our decision to collect a broader retailer cost dataset.[114] EnergyAustralia, Alinta Energy and Red Energy and Lumo Energy noted that the expanded retailer dataset provides a more accurate representation of actual costs faced by retailers and would improve the accuracy and reliability of quantifying retail and other costs.[115] Origin Energy also supported replicating the cost categories used by the ACCC, noting that reporting on a consistent dataset enables retailers to leverage existing data collection systems. This improves efficiencies and reduces regulatory burden on retailers.[116]

In the DMO 7 draft determination, we proposed to set the retail and other costs component based on a customer-weighted average of retailers' reported retail and other cost information.[117] This approach was applied across all DMO regions and customer types. Red Energy and Lumo Energy supported this approach, noting this provides stability and consistency in setting the benchmark for retail and other costs. While acknowledging this methodology gives greater weight to larger retailers, they argued that it's a more robust approach than alternative measures, including the simple average and median, which are more sensitive to fluctuations in year-to-year costs.[118] AGL also endorsed the customer-weighted average approach because it strikes the right balance by incorporating cost data from a broad range of retailers in the market.[119]

In contrast, ENGIE opposed the continued use of customer-weighted average because it understates the true costs to serve for smaller retailers.[120] In their submission, ENGIE recommended using the median because it more accurately reflects the volatility retailers face in the costs of serving customers. ENGIE also argued that the use of the customer-weighted average lacks a sufficient evidence base and should not be justified based on other regulatory instruments such as the VDO.

Consumer groups urged the AER to apply greater scrutiny to the cost data reported by retailers.[121] Energy Consumers Australia (ECA) noted that the substantial increase in the retail and other cost component in the DMO 7 draft determination warrants a further

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114 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 6; AGL, Submission to DMO 7 draft determination, 7 April 2025, p. 4; Red Energy and Lumo Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 1; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 5; JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

115 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 6; Red Energy and Lumo Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 1; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4.

116 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 5.

117 AER, DMO 7 draft determination, Australian Energy Regulator, 13 March 2025, pp. 61–62.

118 Red Energy and Lumo Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 2.

119 AGL, Submission to DMO 7 draft determination, 7 April 2025, p. 4.

120 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 4.

121 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 5; ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 5.

investigation in the reported retail and other costs data.[122] ECA stated that this increase may significantly offset the impact of any measures aimed to ease the pressure of rising energy bills on consumers, including the Australian Government's $1.8 billion extension of energy rebates for households and small businesses.[123] In their joint submission, JEC/ACOSS/SACOSS/QCOSS also encouraged the AER to more rigorously assess retailer cost data to ensure that costs borne by retailers are prudent and fairly passed through to consumers.[124] Given this, JEC/ACOSS/SACOSS/QCOSS did not support the customer-weighted average approach.

In the 14 March Energy and Climate Change Ministerial Council Meeting communique, Ministers encouraged the AER to further interrogate retailer revenues and margins.[125] While this was not a submission to DMO 7, we have taken this communique into account in our final decision.

1st Energy contended that Energy Ministers' call to review retail costs should not result in an artificial lowering of prices that undermines the integrity of the framework.[126] They further stated that the data collected from the cohort of 26 retailers should be accurately reflected in the DMO 7 final determination, and that the AER does not set a benchmark that discourages competition or innovation.

Consumer groups also continued to oppose including costs to acquire and retain customers prices in the DMO.[127] ECA argued that retailers likely recover these costs through what they referred to as a 'loyalty tax', given many customers remain on market offers priced above the DMO.[128] Furthermore, ECA contended that costs to acquire and retain do not reflect an efficient retailer. They stated that new or smaller retailers would spend substantially more on these costs to grow their customer base and these costs would likely be recovered when these retailers become more established. JEC/ACOSS/SACOSS/QCOSS stated that there is no requirement for this allowance to be in the form of a specific, additional cost component.[129] They outlined that these costs have no direct benefit to consumers and are implicitly accounted for within retail margins as retailers can reinvest in the business by acquiring new customers. As such, they argued that there is no justification for treating costs to acquire and retain as a distinct cost element in DMO prices.

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122 ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 5.

123 See the Australian Government's announcement on the Energy Bill Relief Fund for more information. DCCEEW, Energy Bill Relief Fund, Department of Climate Change, Energy, the Environment and Water, 23 March 2025.

124 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 5; ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 5.

125 DCCEEW, Energy and Climate Change Ministerial communique , Department of Climate Change, Energy, the Environment and Water, 14 March 2025.

126 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, p. 5; ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 1.

127 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 5; ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 6–7.

128 ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 5–6.

129 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 5; ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 5–6.

When we sought additional information from retailers on their cost data after the draft determination, we let all stakeholders know that we were still considering our approach to determining retail costs. This included whether to maintain the weighted-average approach or instead use the weighted average based on the number of standing offer customers attributable to each retailer in DMO regions to set the retail and other cost benchmarks. Three retailers and one consumer group provided additional views on this topic.

The 3 retailers did not support the methodological change. Alinta Energy stated that the weighted-average approach more accurately reflects the actual costs faced by all retailers and that a shift in methodology based on standing offer customers would disproportionately reflect the costs of the Big 3 retailers.[130] Although retail costs represent a small component of the DMO, Alinta Energy conveyed concern that frequent changes to the methodology would undermine confidence in the DMO process.[131] Similarly, Energy Locals and ENGIE cautioned that a weighted-average approach based on the number of standing offer customers does not reflect the unique cost pressures faced by smaller retailers.[132] Energy Locals[133] argued that the DMO cost components should be reflective of a prudent retailer and ENGIE[134] proposed adopting the median since the customer-weighted average skews the retail cost estimate in favour of larger retailers that benefit from considerable cost advantages.

ECA reiterated their position from their submission to the DMO 7 draft determination, emphasising that the DMO's objective is to protect disengaged customers who do not benefit from costs relating to customer acquisition or retention.[135] As such, it recommended minimising these and lowering the benchmark for retail costs. ECA also questioned whether increasing costs to acquiring and retaining customers from the Big 3 were efficient, noting most customers are already with these providers.[136]

7.2.2 Bad and doubtful debt

Several stakeholders have identified rising bad and doubtful debt as contributing to the increase in DMO 7.[137]

EnergyAustralia noted that the rise in bad and doubtful debt reflects the growing pressures across the retail sector, particularly larger retailers managing higher costs associated with hardship and debt recovery. They emphasised that these increased retail costs illustrate the

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130 Alinta Energy, Additional retail cost feedback, 7 May 2025, p. 1.

131 Alinta Energy, Additional retail cost feedback, 7 May 2025, p. 2.

132 Energy Locals, Additional retail cost feedback, 28 April 2025, p. 1; ENGIE, Additional retail cost feedback, 24 April 2025, p. 1.

133 Energy Locals, Additional retail cost feedback, 28 April 2025, p. 2.

134 ENGIE, Additional retail cost feedback, 24 April 2025, p. 1.

135 Energy Consumers Australia, Additional retail cost feedback, 30 April 2025, p. 1.

136 Energy Consumers Australia, Additional retail cost feedback, 30 April 2025, p. 1.

137 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 6; Red Energy and Lumo Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 2; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 2; JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 6; ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 7; South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 2.

challenges retailers face in the current high-cost operating environment.[138] Similarly, Red Energy and Lumo Energy highlighted that the rise also stems from growing regulatory requirements and community expectations for retailers, particularly regarding increased support for vulnerable customers.[139] Powershop/Shell Energy further noted that the ongoing cost-of-living pressures have resulted in more customers experiencing financial hardship, which in turn increased the credit risk borne for retailers.

Consumer groups raised concerns that the current methodology may overstate bad and doubtful debt costs because it does not distinguish between actual unrecoverable debts and estimated or mitigated amounts of debt.[140] Given the increase in bad and doubtful costs, JEC/ACOSS/SACOSS/QCOSS considered it necessary for the AER to conduct a more granular assessment of the reported bad and doubtful debt data.[141] They also suggested the AER investigate the extent to which these unrecoverable costs are mitigated or offset by other provisions made by retailers, including sales to debt recovery. This view is also supported by ECA and the South Australian Department for Energy and Mining.[142]

In the DMO 7 draft determination we applied a customer-weighted average to quantify bad and doubtful debt costs by DMO region and customer type.[143] Only one submission commented on this aspect of the methodology, with Origin Energy expressing continued support for the approach.[144]

7.2.3 Smart metering costs

Retailers that commented on smart meter costs in their submissions to the draft determination were in support of the proposed methodology.

EnergyAustralia, ENGIE and Origin Energy supported the AER's current approach of using historic smart meter installation data and including forecast meter installation estimates for the allowance.[145] ENGIE considered this methodology change is more accurate in capturing the true quantum of installations that continue in line with the mandated smart meter rollout.[146]

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138 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 6.

139 Red Energy and Lumo Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 2.

140 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 6; ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 7; South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 2.

141 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 7.

142 South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 2.

143 AER, DMO 7 draft determination, Australian Energy Regulator, 13 March 2025, pp. 72–73.

144 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 6.

145 EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 7; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 5; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 5–6.

146 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 5.

Origin Energy considered the use of actual installations combined with a working capital allowance to be a more accurate approach to deriving smart meter costs than relying solely on forecast installations.[147]

Alinta Energy and EnergyAustralia supported the changes to the calculation of smart meter costs to reflect the change in how legacy meter costs are recovered from customers under the 2025–30 resets for SA Power Networks and Energex.[148]

Powershop/Shell Energy also noted that smart meter rollout is a driver of increasing retailer costs.[149]

JEC/ACOSS/SACOSS/QCOSS expressed concerns that there is a need for greater transparency of how retailers are incurring and recovering the smart meter costs and that they should not be included in retail costs calculations until then.[150] They also suggested that a regulated schedule of costs for smart meter installation and operation, including guidelines on how costs may be recovered from both individuals and the wider customer base, would have merit.

7.3 Final determination

7.3.1 Retail and other costs

Retailer cost data examination

The DMO Regulations require us to determine a ‘reasonable per-customer annual price’ for supplying electricity.[151] In assessing retail costs, we must also have regard to the costs to acquiring and retaining small customers, the cost of serving small customers and any other matter the AER considers relevant.[152]

To meet these objectives, and as we indicated we would do in statements accompanying the publication of our draft determination, we re-examined the retail and other cost data submitted by retailers and used in the calculation of retail and other costs in the draft determination.[153] This included consulting with external stakeholders and issuing a supplementary compulsory information request to the 26 retailers subject to the initial retailer cost data collection to seek further information on retail costs provided in response to the initial information notice.

Several retailers provided further information identifying retail and other costs that we considered were not reasonable to include as part of the retail cost stack. These costs

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147 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 5–6.

148 Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4; EnergyAustralia, Submission to DMO 7 draft determination, 3 April 2025, p. 7.

149 Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 2.

150 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 7.

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

152 Regulations, s. 16(4)(a)–(d).

153 Packham, C. (13 March 2025). Electricity bills to jump as much as 9pc in cost-of-living blow: energy regulator. *The Australian*. https://www.theaustralian.com.au/business/mining-energy/electricity-bills-to-jump-as-much-as-9pc-in-costofliving-blow-energy-regulator/news-story/1f8a3e0777fa1e2fca4249d33f7f3321?btr=eb6035d9026130725a16717085ce99f6

included provisioning for legal matters, costs associated with retailer offerings outside of the scope of the DMO, and other costs accounted for elsewhere in the DMO cost stack, We have excluded these costs from the final DMO prices. These costs have been excluded by DMO region and customer type, which reflects the level of disaggregation provided by retailers and results in reductions between $2.91 to $8.98 (inc. GST).

We have also applied a statistical approach to identifying significant outliers within the dataset, and excluded these outliers from the calculation of the weighted average retail costs. We consider removing outliers from the data provides additional rigour which ensures the resulting retail costs included in the DMO price remain reasonable. This approach has resulted in a reduction between $3.22 and $18.90 (inc. GST) on a per customer basis.

The combined effects of removing outliers and excluded costs results in reductions of between $6.69 and $21.81 (inc. GST) compared to the draft determination, as set out in Table 7.1.

We also received further supporting information from certain retailers on key cost-drivers. This approach aligns with ESC's approach that excludes one-off or non-recurring costs.[154] This allowed us to verify that the data reported by these retailers represent reasonable inputs into the DMO price. This includes detailed explanations of increases in cost-to-serve labour costs, which were primarily driven by hiring additional staff to manage:

- increases in inbound customer calls to retailers due to broader cost-of-living pressures, the energy bill relief scheme and rising bills
- increases in debt collection activity
- higher demand for payment support.

We will conduct our own information collection for the second time in DMO 8 and will apply some lessons from the DMO 7 process to provide additional clarity for retailers on the treatment of certain costs. However, we are satisfied, based on available information, that the retail cost component is a reasonable input and results in a reasonable DMO price. We acknowledge concerns from some stakeholders about the impact retail cost increases have on the DMO price. Nevertheless, we consider that the retail cost component determined in this decision is consistent with the Regulations, which direct the AER to determine a 'reasonable' price.[155]

Maintaining the customer-weighted average approach in DMO 7

We acknowledge ENGIE's suggestion of the median of retailers' actual cost information as an alternative to the customer-weighted average. However, we consider that the customer-weighted average approach provides a more robust and representative basis for setting the retail and other cost benchmark. The customer-weighted average approach ensures the cost structures of retailers serving most customers are reflected and minimises the influence of

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154 ESC, Victorian Default Offer 2024–25 Final Decision Paper, Essential Services Commission, 20 May 2024, p. 30.

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

newer retailers who may be incurring startup costs, which may be more volatile or unrepresentative of the broader retail market.

In contrast, the median represents the midpoint of the reported retailer cost data, which can disregard significant cost variations experienced by retailers in the market. The median is more susceptible to change than the weighted average if the number of retailers included in future dataset changes – for example, if new retailers gain more than 1,000 customers and are included in future requests, if retailers exit the market, or if a retailer is acquired and merged with another retailer. As such, we consider a customer-weighted average approach achieves the right balance between allowing a retailer to return a profit while also setting a reasonable price.

Furthermore, we considered stakeholder views on whether to maintain the customer-weighted average approach, or to adopt a weighted average based on the number of standing offer customers. As noted in these submissions, the customer-weighted average supports regulatory consistency and better reflects the actual costs from most retailers in the market, including smaller retailers. We also need to give further thought and consult with stakeholders on how moving to a weighting based on standing offer customers would be reconciled with our approaches to other parts of the DMO methodology (for example, the market-based approaches for determining reasonable wholesale and environment costs). We will continue to consider the methodology for weighting of retailer costs in DMO 8.

Therefore, for the DMO 7 final determination we maintained setting the benchmark for retail and other costs based on the customer-weighted average of retailers' reported cost data. This includes applying the weighted average to all retail and other cost subcomponents, which encompasses retailers' costs to serve, costs to acquire and retain, and other costs. This weighted average accommodates the retail and other costs of retailers selling to 78% of residential customers and 64% of small business customers in DMO regions, once excluded costs and outlier data has also been accommodated for, as discussed above.

Inclusion of costs to acquire and retain customers in the retail cost stack

In response to consumer groups' argument that costs to acquire and retain customers should not be included the retail cost stack methodology, we note that the Regulations require us consider the costs to acquire and retain customers.[156]

We agree with JEC/ACOSS/SACOSS/QCOSS that individual retailers may make strategic decisions to forego margin by increasing spending in costs to acquire and retain customers. However, we do not agree that it necessarily follows that costs to acquire and retain customers should not be explicitly accounted for and instead be included in the 6% and 11% retail margins.

The analysis of earnings before interest, tax, depreciation and amortisation (EBITDA) margins in our draft determination and previous DMO determinations, as well as ACCC findings, already account for the average costs retailers incur to acquire and retain customers. That is, average EBITDA margins are calculated once average customer acquisition and retention costs are subtracted from revenue. Based on our margins analysis

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156 Regulations, s. 16(4)(c)(iv).

in the draft determination, the weighted average EBITDA margin was 5.6% for residential customers and 11.6% for small businesses.[157]

If the EBITDA margins were recalculated such that costs to acquire and retain customers were not subtracted and instead fell within EBITDA, then these margins would be higher. Under such a DMO cost stack approach we may conclude that, while retail and other costs would be lower, margins would be higher. As such, we maintain it is appropriate to explicitly include costs to acquire and retain customers in the cost stack methodology.

Given the retailer cost data we have collected relates to the 2023–24 period, we have also applied forecast CPI using RBA forecast inflation for 2024–25 and 2025–26 to retain the value of these costs in real terms across the DMO 7 period.[158]

Table 7.1 and Table 7.2 provides an updated breakdown of retail and other cost components by DMO region for residential customers and small businesses, respectively.

Table 7.1 Retail and other costs ($/customer), by DMO region, residential customers, inc. GST

Category	Retail and other costs	NSW	SE Queensland	South Australia
Draft determination	Cost to serve	$112.02	$114.71	$108.23
	Cost to acquire and retain	$72.81	$60.45	$68.04
	Other costs	$27.14	$44.44	$31.83
	Total	**$211.97**	**$219.60**	**$208.10**
Final determination	Cost to serve	$109.61	$110.51	$105.58
	Cost to acquire and retain	$72.30	$58.20	$67.26
	Other costs	$22.80	$31.47	$28.57
	Total	**$204.70**	**$200.19**	**$201.41**
Change	Cost to serve	-$2.41	-$4.20	-$2.64
	Cost to acquire and retain	-$0.52	-$2.25	-$0.78
	Other costs	-$4.35	-$12.97	-$3.26
	Total	**-$7.27**	**-$19.42**	**-$6.69**

Source: AER analysis of retail cost information.

157 AER, DMO 7 draft determination, Australian Energy Regulator, 13 March 2025, p. 81.

158 We have used Reserve Bank of Australia (RBA) February 2025 forecast inflation for June 2025 (2.4%) and June 2026 (3.2%).

Table 7.2 Retail and other costs ($/customer), by DMO region, small businesses, inc. GST

Category	Retail and other costs	NSW	SE Queensland	South Australia
Draft determination	Cost to serve	$157.69	$129.09	$129.06
	Cost to acquire and retain	$80.34	$63.01	$72.58
	Other costs	$54.79	$29.67	$36.77
	Total	**$292.82**	**$221.78**	**$238.41**
Final determination	Cost to serve	$146.27	$125.33	$117.94
	Cost to acquire and retain	$77.86	$61.56	$66.28
	Other costs	$53.57	$25.62	$32.38
	Total	**$277.70**	**$212.51**	**$216.60**
Change	Cost to serve	-$11.42	-$3.76	-$11.12
	Cost to acquire and retain	-$2.48	-$1.45	-$6.30
	Other costs	-$1.22	-$4.05	-$4.39
	Total	**-$15.12**	**-$9.27**	**-$21.81**

Source: AER analysis of retail cost information.

7.3.2 Bad and doubtful debt

For the DMO 7 final determination we maintained the customer-weighted average approach to quantify bad and doubtful debt. This approach was applied to the bad and doubtful debt data reported by the cohort of 26 retailers by DMO region across residential customers (with and without controlled load) and small businesses. We also applied the same approach to removing significant outliers from the dataset, as discussed in section 7.3.1.

We acknowledge consumer groups' concerns about the distinction between actual and estimates of bad and doubtful debt. We intend to investigate this further in DMO 8.

Table 7.3 shows the change in bad and doubtful debt costs from the DMO 7 draft determination to our final determination as a result of removing significant outliers. Compared with DMO 6, residential bad and doubtful debt has remained stable in SA Power Networks but increased between $6.08 and $12.59 for residential customers in other DMO regions (inc. GST). Small business bad and doubtful debt decreased in SA Power Networks by $6.81 and increased $14.41 and $17.03 in SE Queensland and NSW respectively.

Table 7.3 Bad and doubtful debt in DMO 7 ($/customer), inc. GST

DMO region	Final determination bad and doubtful debt	Draft determination bad and doubtful debt	Change
Residential customers, with and without controlled load			
Ausgrid	$39.08	$42.13	-$3.05
Endeavour Energy	$39.08	$42.13	-$3.05
Essential Energy	$39.08	$42.13	-$3.05
Energex	$38.99	$40.05	-$1.06
SA Power Networks	$43.60	$43.94	-$0.33
Small businesses			
Ausgrid	$88.53	$101.01	-$12.47
Endeavour Energy	$88.53	$101.01	-$12.47
Essential Energy	$88.53	$101.01	-$12.47
Energex	$60.61	$77.53	-$16.92
SA Power Networks	$50.39	$74.72	-$24.33

Source: AER analysis of retail cost information.

7.3.3 Smart metering costs

Our updated retailer data requests issued on 31 March 2025 sought:

- the number of customers by meter and tariff type
- the projected customer numbers as at 31 December 2025
- smart meter costs
- any one-off or up-front fees for installation
- information on whether the costs are inclusive or exclusive of the costs incurred that are then recovered by charging that particular customer an up-front fee.

A group of 11 retailers selling to approximately 94% of customers in DMO regions responded, with a new additional retailer compared with DMO 6. In Figure 7.2 we have outlined a historic trend analysis of the rate of installations (September 2021 to March 2025). The rate of installations has gradually increased in all regions.

The proportion of smart meters in DMO regions continues to increase across DMO decisions:

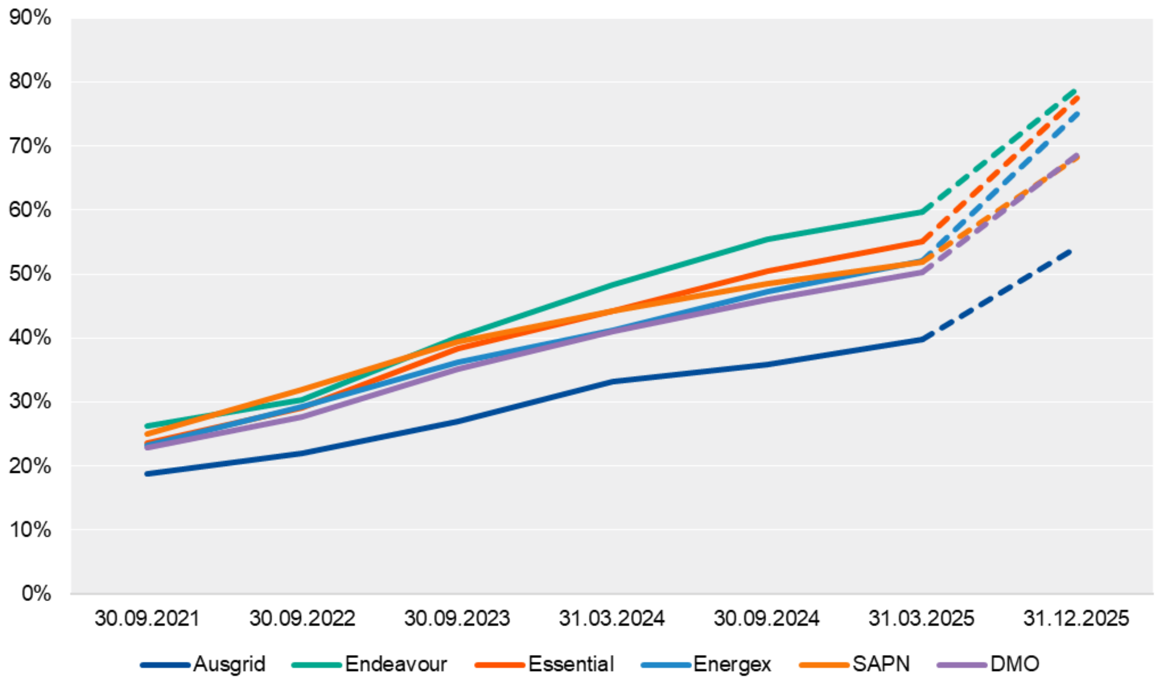
- 41.0% in the DMO 6 final determination (31 March 2024 data)
- 46.1% in the DMO 7 draft determination (30 September 2024 data)

- 50.3% in the DMO 7 final determination (31 March 2025 data).

This equates to an approximate increase of around 20% to 25% in the number of customers with smart meters since the DMO 6 final determination.

The retailer forecasts have a similar trend as in previous years in all DMO regions. The proportion of smart meters is projected by retailers to reach 68.9% of the customer base across all DMO regions at 31 December 2025, as set out in Figure 7.2.

Figure 7.2 Historic and projected smart meter installations, residential customers and small businesses



Source: AER analysis of retailer smart meter costs and count data.

The AER acknowledges the submission from JEC/ACOSS/SACOSS/QCOSS and the need for transparency on these costs. We have sought greater detail from retailers on how these costs are being incurred and recovered. Retailers' responses indicate the costs included are the direct costs incurred by external meter providers and do not include internal operating expenses such as labour, systems or management costs. Retailers also indicated that these costs are recovered across all customers, not just from customers with smart meters.

For the DMO 7 final determination, we have maintained the approach of basing the smart meter costs on actual installations, as at 31 March 2025, and including a cost of capital allowance based on the projected number of installations that will have occurred at the midpoint of DMO 7, 31 December 2025.

Smart meter costs for DMO 7 are set out in Table 7.4 and Table 7.5. Appendix B provides a detailed breakdown of our calculation of smart meter costs.

Table 7.4 Average residential smart meter cost, by DMO region, excl. GST

DMO region	Average annual cost per smart meter	Average annual cost per customer
Ausgrid	$116.66	$47.22
Endeavour Energy	$118.50	$74.57
Essential Energy	$126.39	$74.11
Energex	$117.57	$64.91
SA Power Networks	$118.21	$64.99

Table 7.5 Average small business smart meter cost, by DMO region, excl. GST

DMO region	Average annual cost per smart meter	Average annual cost per customer
Ausgrid	$127.69	$30.05
Endeavour Energy	$133.58	$56.06
Essential Energy	$140.03	$61.10
Energex	$144.12	$61.97
SA Power Networks	$137.74	$53.84

Queensland and South Australia network determinations and legacy meter cost recovery

In DMO 4 and DMO 5 the non-capital component of alternative control services (ACS) metering charges was subtracted from smart meter costs. This adjustment was necessary to avoid over-recovery for smart meters because:

- the full ACS metering charges were already included in the network costs component
- most smart meter customers would not be charged the non-capital component.

In the lead up to DMO 6, NSW network businesses underwent network resets and changed their cost recovery approach to recover these costs from all customers regardless of whether they had a smart meter installed. In DMO 6 the AER updated the smart meter allowance calculation by removing the subtraction of the non-capital component of ACS metering charges.

For DMO 7 we have accounted for recent changes to legacy meter cost recovery approaches for SA Power Networks and Energex from their recent draft network revenue determinations. Legacy meter costs will be recovered from all customers, including smart meter customers, which is the same approach as for Endeavour Energy and Essential Energy.

The smart meter allowance calculations have been updated for SA Power Networks and Energex in DMO 7. Because of this, in addition to the steady increase in smart meter installations, smart meter costs for DMO 7 have increased in SA Power Networks and Energex.

Appendix B sets out a detailed breakdown of our calculation of smart meter costs.

7.4 Summary of determinations for retail costs

Table 7.6, Table 7.7 and Table 7.8 set out the components for our cost build-up approach in DMO 7.

Table 7.6 Residential without controlled load retail costs, excl. GST

DMO region	Retail and other costs	Smart meter costs	Bad and doubtful debt costs	Forecast CPI adjustment	Total	Difference to DMO 6 (%)
Ausgrid	$186.09	$47.22	$35.53	$15.26	$284.10	25.9%
Endeavour Energy	$186.09	$74.57	$35.53	$16.81	$313.01	28.0%
Essential Energy	$186.09	$74.11	$35.53	$16.79	$312.51	27.3%
Energex	$181.99	$64.91	$35.45	$16.03	$298.37	35.4%
SA Power Networks	$183.10	$64.99	$39.64	$16.33	$304.07	23.6%

Table 7.7 Residential with controlled load retail costs, excl. GST

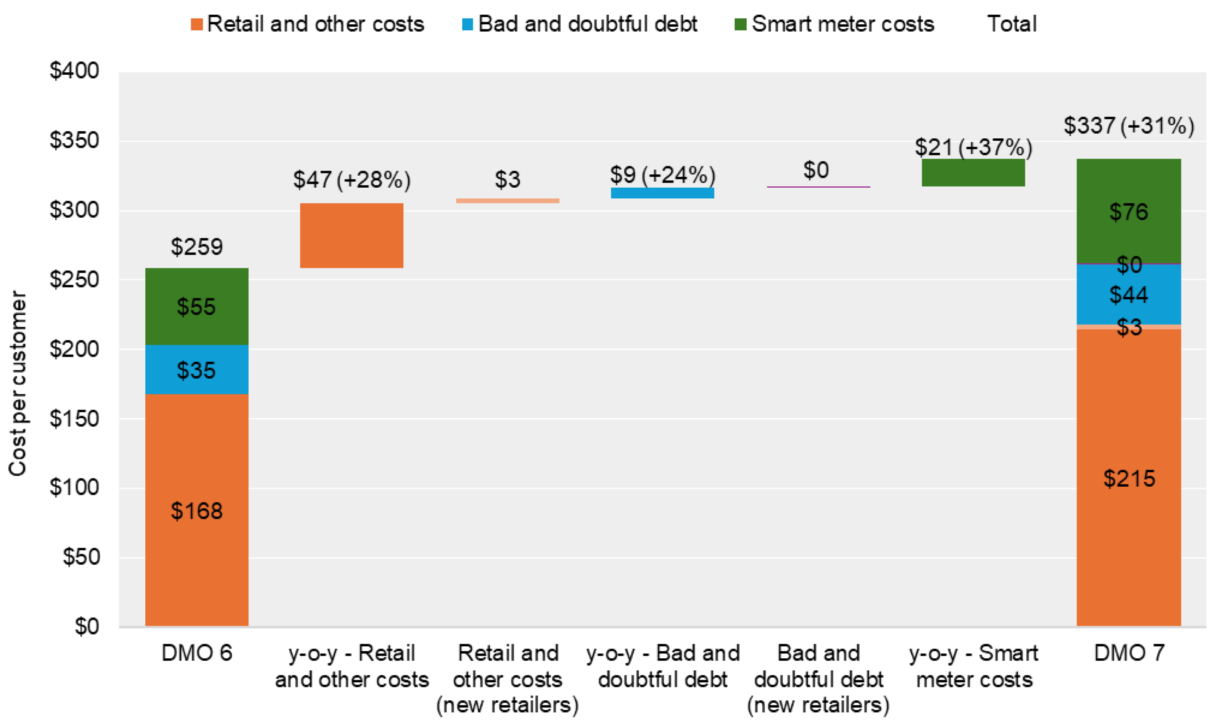
DMO region	Retail and other costs	Smart meter costs	Bad and doubtful debt costs	Forecast CPI adjustment	Total	Difference to DMO 6 (%)
Ausgrid	$186.09	$47.22	$35.53	$15.26	$284.10	25.9%
Endeavour Energy	$186.09	$74.57	$35.53	$16.81	$313.01	28.0%
Essential Energy	$186.09	$74.11	$35.53	$16.79	$312.51	27.3%
Energex	$181.99	$64.91	$35.45	$16.03	$298.37	35.4%
SA Power Networks	$183.10	$64.99	$39.64	$16.33	$304.07	23.6%

Table 7.8 Small business retail costs, excl. GST

DMO region	Retail and other costs	Smart meter costs	Bad and doubtful debt costs	Forecast CPI adjustment	Total	Difference to DMO 6 (%)
Ausgrid	$252.46	$30.05	$80.49	$20.61	$383.59	29.3%
Endeavour Energy	$252.46	$56.06	$80.49	$22.08	$411.08	33.1%
Essential Energy	$252.46	$61.10	$80.49	$22.37	$416.41	35.2%
Energex	$193.19	$61.97	$55.10	$17.61	$327.87	17.5%
SA Power Networks	$196.91	$53.84	$45.81	$16.83	$313.39	8.3%

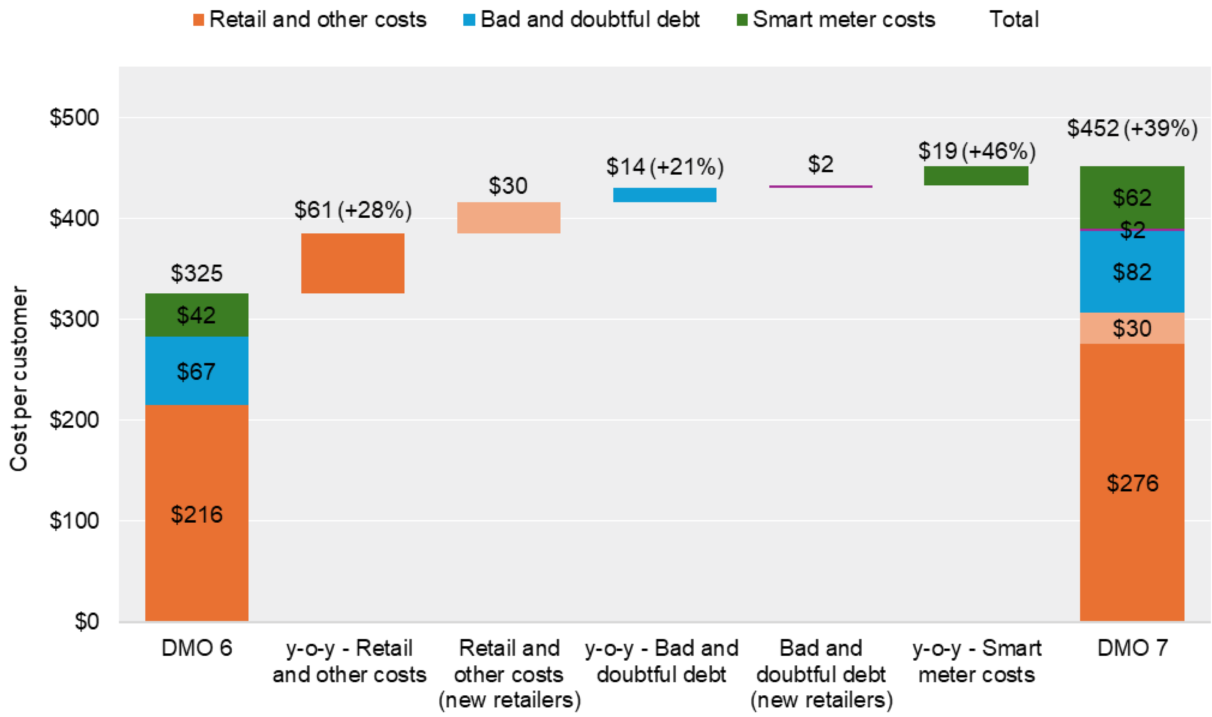
Figure 7.3 and Figure 7.4 illustrate the year-on-year increases in retail costs, and the impact on the customer-weighted average of retail costs, by including new retailers in the DMO 7 draft determination. These costs are averaged across all regions to summarise these movements.

Figure 7.3 Change in residential retail cost components from DMO 6 to DMO 7 ($/customer), all DMO regions



Source: AER analysis of retailer cost data and retailer smart meter costs and count data.

Figure 7.4 Change in small business retail cost components from DMO 6 to DMO 7 ($/customer), all DMO regions



Source: AER analysis of retailer cost data and retailer smart meter costs and count data.

8 Retail margins

- For the DMO 7 final determination, we have decided to maintain the retail margins at 6% for residential customers and 11% for small business customers, excluding any competition allowance.
- While we have held the margin steady as a percentage of the DMO price, increases in the underlying cost stack mean that, in dollar terms, margins have increased from DMO 6 between $0.65 and $16.75 for residential customers and between $3.66 and $53.79 for small businesses, depending on DMO region.

The Regulations require the DMO price be set such that it allows retailers to make a reasonable profit in supplying electricity.[159] To meet this objective, we split the retail allowance into separate margin and competition allowance components in DMO 7. This chapter discusses our considerations of retail margins and chapter 9 discusses our consideration of the competition allowance.

8.1 Draft determination

In our DMO 7 draft determination, we proposed setting retail margins as a percentage of the DMO price (before applying a competition allowance), with margins of 6% for residential customers and 11% for small business customers. Based on our analysis of various sources of retail margins in the 2023–24 year, we considered these values for retail would allow retailers to make a reasonable profit in supplying electricity.

8.2 Stakeholder views

Nine stakeholders submitted feedback on issues relating to retail margins.

Most retailers, including ENGIE, Alinta Energy, AGL, AEC, and Origin Energy, supported our decision to maintain the retail margins of 6% and 11% for residential customers and small business customers, respectively.[160]

ENGIE noted that these margins sit at the lower end of a reasonable range and cautioned that any further reduction would heighten risks to smaller retailers as actual margins are at historic lows.[161] It also encouraged the AER to maintain these margins in future DMO determinations, for regulatory certainty. Similarly, the AEC noted that the current margins align with regulatory goals and reflect the tight and risky environment retailers face, particularly for smaller retailers.[162] With margins at historic lows and the competition

159 Regulations, s. 16(4)(b).

160 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 5; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4; AEC, Submission to DMO 7 draft determination, 8 April 2025, p. 1; Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 1–2.

161 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 5.

162 AEC, Submission to DMO 7 draft determination, Australian Energy Council, 8 April 2025, p. 1.

allowance still suspended, the AEC argued these margins should be preserved and potentially increased to ensure retailer viability.[163]

AGL and ENGIE supported the AER's approach of applying a percentage-based retail margin.[164] AGL noted that ongoing retail market pressures are compressing retail margins across most regions, with many retailers facing significantly lower retail margins in pursuit of customer growth.[165] It contended that competition and long-term market efficiencies would be undermined if the regulated retail margin were set below an efficient return and that an appropriate margin is critical to support retailer viability and investment.[166]

Origin Energy stated that the current retail margins align with regulatory objectives by enabling a prudent retailer, facing the typical costs of supplying electricity, to earn a reasonable profit.[167] It emphasised that retail margins should compensate the level of risk borne by retailers. The greater the risk, the greater the retail margin that is required for the retailers to earn an appropriate return. This is distinct from EBITDA, which measures a retailer's operational profitability.[168]

In support of retaining the margins, Origin Energy cited that our weighted-average inferred EBITDA of 5.6% demonstrates that retailers have been able to achieve a reasonable rate of return relative to our proposed margins.[169] Origin Energy also cited Frontier Economics' expected returns modelling, which estimates the minimum margin needed to compensate for non-diversifiable risk.[170] It argued that the current 6% margin is set at a conservative level, and due to excluding the competition allowance, Origin Energy sees little justification for any change to the current retail margins.

These sentiments were reiterated in workshops with retailers and through several meetings held between the AER and individual retailers on request.

In contrast, consumer groups generally disagreed with our decision to maintain the margins in DMO 7.[171] ECA recommended that the AER align the small business retail margins with residential customers.[172] It noted its Consumer Energy Report Card survey found three-quarters of small businesses have raised concerns about the cost of electricity[173] and pointed to the AER's retail quarterly performance reports stating that the average energy debt of a

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163 AEC, Submission to DMO 7 draft determination, Australian Energy Council, 8 April 2025, p. 1.

164 AGL, Submission to DMO 7 draft determination, 7 April 2025, p. 4; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 5.

165 AGL, Submission to DMO 7 draft determination, 7 April 2025, p. 4.

166 AGL, Submission to DMO 7 draft determination, 7 April 2025, p. 4.

167 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, pp. 1–2.

168 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 6.

169 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 6.

170 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 6.

171 ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, pp. 7–8; South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 3; JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, pp. 7–8.

172 ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, pp. 7–8.

173 ECA, Consumer Energy Report Card, Energy Consumers Australia, December 2024.

small business is almost twice as high as residential customers.[174] ECA also emphasised that, since small businesses are more likely to be on a standing offer, it is critical to ensure that these customers have access to reasonable prices.[175]

Similarly, the SA Business Chamber advocated for reducing retail margins for small businesses from 11% to 6% to align with residential customers.[176] It cited its findings from the December 2024 Survey of Business Expectations that showed three-quarters of small businesses ranked the cost of doing business among their top 5 concerns. The SA Business Chamber highlighted that rising electricity prices are a constant source of concern for businesses and this was also reflected in their survey results.[177] While the SA Business Chamber agreed retailers should be able to make a reasonable profit, it stressed that these margins should be balanced with the principle that small electricity customers should make a reasonable profit, or at a minimum, remain solvent.[178]

The SA Business Chamber also pointed out that EBITDA reflects a retailers' earnings after accounting for its costs of delivering electricity to customers, including bad and doubtful debts in the retail cost stack, and stated that using this to substantiate a higher retail margin may result in double-counting.[179] As such, it is concerned that this creates a potential cycle where higher costs contribute to further risk of higher bad and doubtful debt costs.[180] Finally, it stated that South Australian electricity customers appear to be paying a premium to cover the risk management and contingency planning of retailers and government, including estimates for bad and doubtful debt risk management, market volatility and the growing impact of programs such as the Small Claims Compensation Scheme and Firm Energy Reliability Mechanism.[181]

JEC/ACOSS/SACOSS/QCOSS considered the 6% retail margins for residential customers was towards the higher end of ranges outlined in previous DMO determinations.[182] It argued that if the margins were maintained, it should offset any additional cost allowances set elsewhere in the DMO and remove the need to include costs to acquire and retain customers and competition allowance.[183] The joint submission also noted that the VDO has set an efficient retail margin of 5% in its draft decision and that setting a margin towards the lower end of a 'reasonable' range does not prevent retailers from recovering greater margins from other products and services not covered by the DMO.[184]

The South Australian Department for Energy and Mining submitted that there is an opportunity to improve outcomes for consumers by reducing the proposed 6% and 11%

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174 ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, pp. 7–8; AER, Quarter 2 2024–25 Retail Performance Data Schedule 3, Australian Energy Regulator, 18 March 2025.

175 ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, pp. 7–8.

176 SA Business Chamber, Submission to DMO 7 draft determination, 1 May 2025, p. 2.

177 SA Business Chamber, Survey of Business Expectations, December 2024.

178 SA Business Chamber, Submission to DMO 7 draft determination, 1 May 2025, p. 2.

179 SA Business Chamber, Submission to DMO 7 draft determination, 1 May 2025, pp. 2–3.

180 SA Business Chamber, Submission to DMO 7 draft determination, 1 May 2025, p. 3.

181 SA Business Chamber, Submission to DMO 7 draft determination, 1 May 2025, p. 3.

182 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, pp. 7–8.

183 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, pp. 7–8.

184 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 8.

margins, particularly since these have led to significant dollar increases in the DMO 7 draft determination.[185] It also cautioned that using a percentage-based approach will amplify price rises as other cost components grow. Referring to Frontier Economics' advice to the Independent Competition and Regulatory Commission for the 2024–27 period, it cited that a margin, in percentage terms, overcompensates retailers as increased energy costs would reduce the risks retailers face.[186] As such, it recommended the AER consider a hybrid or fixed-dollar approach to quantify margins.[187]

The NSW Minister for Energy commented that proposed retail margins in NSW are not appropriate given that the actual margins found by the ACCC's December 2024 Inquiry into the NEM were significantly smaller in NSW at 4% in 2023–24 and between 0% and 4% since 2019–20.[188] The NSW Minister for Energy also raised concerns that, since retail margins reflect a percentage of the DMO cost stack components, this led to a substantial increase in the absolute dollar value of margins.[189]

8.3 Final determination

For the DMO 7 final determination we have decided to maintain the retail margins of 6% for residential and 11% for small business customers.

To ensure that these margins remain appropriate for DMO 7, we analysed retail margins for residential customers (both with and without controlled load) and small business customers using a range of approaches. A summary is provided in Table 8.1. This analysis included:

- retail margins inferred from 2023–24 EBITDA data reported by retailers
- retail margins inferred from the ACCC's customer-weighted average annual prices
- ACCC analysis of actual retail margins in its December 2024 report
- using advertised market offers to infer retail margins
- benchmarking regulatory decisions of retail margins in other jurisdictions.

The range of margins presented reflects the differences in the scope data used across each approach. For example, using advertised market offers tends to result in lower retail margins. This is because these offers are typically discounted to attract new customers, with many discounts expiring after a fixed period, leading to temporarily lower prices.

Across all DMO regions, analysis of EBITDA as a percentage of retailers' reported revenue results in a customer-weighted average margin of 5.6% for residential customers and 11.6% for small businesses. This measure captures the margins retailers operating in a competitive

185 South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 3.

186 South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 3.

187 South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 3.

188 The Hon Penny Sharpe MLC, Minister for Climate Change, Energy, Environment and Heritage, Submission to DMO 7 draft determination, 10 April 2025, p. 1.

189 The Hon Penny Sharpe MLC, Minister for Climate Change, Energy, Environment and Heritage, Submission to DMO 7 draft determination, 10 April 2025, p. 1.

environment are achieving across all market offer customers, including both engaged customers that switch to acquisition offers and disengaged customers that may be on old market offers that return greater margins.

An additional advantage of this approach stems from the underlying data used to infer retail margins. The retail cost information, collected directly from 26 retailers representing approximately 99% of the market share in 2023–24, provides a more comprehensive view of the actual margins incurred by retailers. By applying a weighted-average approach, we can more accurately reflect the margins faced by a wide range of retailers, including smaller retailers that may experience more financial constraints compared with larger retailers. Given this, we have placed greater emphasis on this approach to inform the margins for residential and small businesses in DMO 7.

Table 8.1 Range of inferred margins under various approaches

Approach	Residential without CL	Residential with CL	Small businesses
Reported EBITDA margins using AER retailer cost data[190]	-39.9% to 29.4% (weighted avg. of 5.6%)		-33.4% to 29.4% (weighted avg. of 11.6%)
Reported EBITDA margins from ACCC's December 2024 report	4.2% (NSW), 9.2% (SE Queensland), 12.8% (South Australia)		9.5% (NSW), 11.5% (SE Queensland), 19.2% (South Australia)
Inferred margins using ACCC customer-weighted prices	-2.0% to 2.8%	3.1% to 10.5%	1.4% to 4.0%
Inferred margins using advertised market offers	-5.6% to 2.2%	-6.3% to 1.4%	7.0% to 10.7%

Source: AER updated analysis of ACIL Allen's retail margin analysis on advertised market offers; AER analysis of retail margins (EBITDA) based on retailer data for 2023–24; AER analysis of ACCC customer-weighted prices paid on 1 August 2024. Margins inferred using DMO 6 costs.

Based on our most recent analysis, we do not support the ECA's and the SA Business Chamber's recommendation to align small business retail margins with residential customers. Small businesses and residential customers have distinct consumption patterns and involve different cost structures and risk profiles for retailers. For example, higher average small business debt among small businesses indicates that serving small businesses comes at a greater financial risk to retailers.

Noting the EBITDA data reported by retailers for 2023–24, if we estimated a single weighted-average retail margin across both residential and small business customer types, this would underestimate small business margins and overestimate residential margins.

190 One small retailer from our retail cost information request is an outlier, so was excluded from the ranges from this table. However, the data for this retailer is included in the weighted average calculation.

Our analysis of margins across the various approaches also indicates it remains appropriate to set a higher margin for small businesses than for residential customers. Maintaining differentiated margins between residential and small business aligns with the requirements of the Regulations, which contemplates distinct types of small customers.

We acknowledge JEC/ACOSS/SACOSS/QCOSS's combined submission that stated that if the margins were maintained, it should offset any additional cost allowances set elsewhere in the DMO and justify the removal of an allowance for the cost of acquiring and retaining customers. However, the Regulations direct us to have regard to costs to acquire and retain customers.[191] We do not think it is appropriate for the retail margin to offset other costs that we must have regard to because the Regulations also require the DMO price to allow retailers to make a reasonable profit.[192]

In response to the South Australian Department for Energy and Mining's proposal to consider a hybrid approach that combines both fixed and percentage margins, we maintain that a percentage-based approach is more appropriate to ensure the risks scale with the underlying costs that retailers face. Percentage-based margins are also simple and transparent for retailers and consumers and are more closely aligned with the current market conditions, such as increases in price volatility.

In contrast, a hybrid approach introduces methodological complexities. Determining an appropriate fixed-cost component would require further consultation with stakeholders to identify what share of total DMO price should be fixed, including retail operating costs, network costs and wholesale electricity costs.[193] We also understand that stakeholders value regulatory consistency. Shifting from the current percentage-based approach would lead to further changes and uncertainty in our framework.

We also acknowledge the NSW Minister for Energy's observation that the ACCC has reported retailers achieved comparatively lower margins in NSW in 2022–23 and 2023–24. However, the ACCC noted that these low margins in NSW in 2022–23 were largely attributable to accelerated depreciation of the Eraring coal-fired plant and, without Origin Energy's NSW data, average margins would have increased substantially.[194] We note in Origin Energy's most recent financial report it has re-evaluated Eraring's useful life and has decelerated the depreciation due to an agreement with the NSW Government to delay the retirement of Eraring.[195] Our analysis of customer prices in 2023–24 also found inferred EBITDA margins in NSW were consistent with other regions.[196] We consider it important that retail margins are set uniformly across all regions so that customers do not face different margins just because of where they are located within DMO regions.

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191 Regulations, s. 16(4)(c)(iv).

192 Regulations, s. 16(4)(b).

193 Frontier Economics, Retail electricity price investigation 2024-27: Report for the Independent Competition and Regulatory commission p. 63.

194 ACCC, Inquiry into the National Electricity Market December 2023 report, Australian Competition and Consumer Commission, December 2023, p. 36.

195 Origin Energy, Annual Report 2024, p. 87.

196 AER, DMO 6 draft determination, Australian Energy Regulator, March 2024, p. 60.

We recognise the ongoing high-cost environment facing small businesses and will continue to explore alternative approaches in future DMO determinations, where supported by robust evidence and consistent with the Regulations.

8.4 Summary

The DMO 7 final determination maintains retail margins at 6% of residential and 11% of small business DMO prices, excluding any competition allowance. This is summarised in Table 8.2.

Table 8.2 Efficient retail margins, DMO 7 final determination and DMO 6 final determination (including GST)

Customer type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Residential customers without controlled load					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 7 ($)	$117.88	$144.68	$164.45	$128.55	$138.03
Retail margin in DMO 6 ($)	$108.61	$133.40	$150.75	$123.94	$133.80
Difference ($)	$9.27	$11.28	$13.70	$4.61	$4.23
Residential customers with controlled load					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 7 ($)	$163.02	$184.33	$192.64	$145.48	$169.43
Retail margin in DMO 6 ($)	$150.56	$168.06	$175.89	$144.84	$165.58
Difference ($)	$12.46	$16.27	$16.75	$0.65	$3.86
Small businesses					
Efficient margin	11%	11%	11%	11%	11%
Retail margin in DMO 7 ($)	$547.52	$525.28	$684.43	$472.33	$609.51

Customer type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Retail margin in DMO 6 ($)	$507.30	$486.39	$630.64	$468.67	$588.72
Difference ($)	$40.22	$38.88	$53.79	$3.66	$20.79

9 Competition allowance

- For the DMO 7 final determination we have calculated competition allowance values that would allow retailers serving 90% of customers to make a reasonable profit.
- This results in a competition allowance of $22.61 for residential customers and $26.19 for small business customers (excluding GST).
- Due to sustained cost-of-living pressures as indicated by the sustained nature of elevated underlying inflation, DMO 7 does not include the competition allowance.

The Regulations require us to set a reasonable price and have regard to the principle that retailers should be able to make a reasonable profit.[197] We also consider the policy objectives of:

- protecting consumers from unreasonably high prices
- allowing retailers to recover their efficient costs of providing services
- incentivising retailers to invest, innovate and compete in the market and incentivising customers to engage in the market.

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

The retail allowance was set to reflect a return on retailer risk, allow for differences in retailers' costs and provide additional room for competition.[198] We also considered it desirable that DMO prices include a similar level of allowance regardless of DMO region.

In setting the DMO price, we must have regard to any matter we consider relevant. One of these matters is electricity affordability, which remains a key issue for households and small businesses and is raised across many of the submissions to our process. Many customers continue to face challenges to absorb higher electricity prices in the current economic climate.

Since DMO 6 we have separately calculated a retail margin and a competition allowance, providing a mechanism for the DMO to explicitly reflect our considerations of electricity affordability and cost-of living pressures.

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

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

198 The DMO prices also include a separate allowance for the costs of competition because they include the average costs to acquire and retain customers.

In DMO 6 we determined not to include the competition allowance to give greater weighting to the price protection objectives of the DMO during a period of sustained high inflation and heightened cost-of-living pressures.

9.1 Draft determination

9.1.1 Quantifying the competition allowance

In our draft determination, we stated that we had determined the competition allowance method based on the spread of individual retailer costs to serve reported to the AER through formal information requests to retailers. These information requests were sent to 26 retailers, accounting for approximately 99% market share of residential and small business markets.

Many of the smaller retailers included in our information request do not exhibit the economies of scale of the larger retailers and in some instances report costs to serve that are materially higher than the weighted average of all retailers. As such, for the DMO 7 draft determination we determined to set the competition allowance such that retailers selling to 90% of the market would be able to make a reasonable profit with the competition allowance included in the DMO price.

We considered that setting the competition allowance to accommodate the costs to serve of retailers selling to 90% of customers in DMO regions contributes to the achievement of the DMO objective of incentivising competition because it enables a significant proportion of retailers to achieve a reasonable profit. It also avoids the competition allowance being excessively large due to the impact of more inefficient retailers, which would be inconsistent with the DMO pricing protection objectives.

9.1.2 Inclusion/exclusion of the competition allowance

Our draft determination indicated that we consider that cost-of-living pressures remain a relevant matter. Therefore, it is a matter the AER must have regard to under s.16(4)(d) of the Regulations.

We stated that trimmed mean CPI is the most appropriate metric for gauging cost-of-living pressures, given headline CPI movements have been driven in part by reductions in electricity prices due to temporary government electricity bill relief. We noted that 12-month movements in underlying CPI, reported on quarterly by the Australian Bureau of Statistics (ABS), would be the primary factor we would have regard to when determining to include the competition allowance. Where underlying CPI is materially above the RBA's target band of 2% to 3% for a sustained period, we stated we would exclude a competition allowance to prioritise consumer protections.

At the time of the draft determination, the most recent quarterly update by the ABS for annual CPI movements was for December 2024, with trimmed mean CPI inflation sitting at 3.2%. Therefore, we determined that due to the sustained nature of CPI inflation, we would exclude the competition allowance from the DMO 7 draft determination. However, we noted that for the final determination the ABS March 2025 quarter CPI data would be available. We stated that we would consider the updated CPI data and would reassess whether it remains appropriate to exclude the competition allowance for DMO 7 in our final determination.

9.2 Stakeholder views

Twelve stakeholders submitted feedback on issues relating to the competition allowance. Feedback focused on the quantification of the competition allowance and its inclusion or exclusion from the DMO cost stack.

9.2.1 Quantifying the competition allowance

ENGIE submitted that the calculated competition allowance in the draft determination was a material departure from the values determined, but not used, in DMO 6 and requested further clarification on what led to this change.[199]

Origin Energy submitted that determining a competition allowance that would allow most, but not all, retailers to cover their costs would be sufficient to incentivise competition.[200] They noted that while the calculated allowance may meet the objective of accommodating differences in retailers' costs, it does not meet the objective to provide room for competition. Finally, Origin Energy submitted that the competition allowance should not be designed as a cost recovery amount but instead calculated on the basis to stimulate competition.

9.2.2 Inclusion/exclusion of the competition allowance

On the consequences of excluding the competition allowance

The AEC, ENGIE, Energy Locals, Powershop/Shell Energy and AGL did not support excluding the competition allowance from the draft determination, noting its ability to support innovation and competition.[201] Powershop/Shell Energy cited the role of the competition allowance in providing for the costs of acquiring and retaining customers and, along with ENGIE, submitted that the exclusion of the competition allowance would hinder the ability for smaller retailers to compete with larger retailers.[202] Additionally, in workshops with retailers it was proposed that it was not the AER's role to be lowering the DMO price in response to cost-of-living pressures, stating external measures, such as energy bill relief, were better suited to the task.

ECA and the South Australian Department for Energy and Mining submitted that the exclusion of the competition allowance should be permanent, given its exclusion from DMO 6 has not had a noticeable impact on competition.[203] A joint submission from JEC/ACOSS/SACOSS/QCOSS proposed that the competition allowance should be permanently removed to prioritise energy affordability.[204]

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199 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 6.

200 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 7.

201 AEC, Submission to DMO 7 draft determination, Australian Energy Council, 8 April 2025, p. 1; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 5; Energy Locals, Submission to DMO 7 draft determination, 3 April 2025, p. 1; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 3; AGL, Submission to DMO 7 draft determination, 7 April 2025, p. 4.

202 Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 3; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

203 ECA, Submission to DMO 7 draft determination, Energy Consumers Australia, 3 April 2025, p. 7; South Australian Department for Energy and Mining, Submission to DMO 7 draft determination, 14 April 2025, p. 2.

204 JEC/ACOSS/SACOSS/QCOSS, Submission to DMO 7 draft determination, 3 April 2025, p. 8.

On the basis for decision-making

The AEC, ENGIE, Alinta Energy and 1st Energy submitted that the position in the draft determination to use underlying inflation as the primary factor in our decision-making represented a shift from the DMO 7 issues paper and raised concerns around regulatory certainty and transparency.[205] Further, ENGIE and Powershop/Shell Energy consider CPI is a lagging indicator, so may not be the best indicator for cost-of-living pressures, and the AER should have regard to RBA inflation forecasts, as in their Statement on Monetary Policy[206] This view was also conveyed in workshops, with retailers considering the current criteria are not thoroughly objective and do not promote regulatory certainty.

ENGIE and Energy Locals submitted that the AER had not sufficiently considered the state of retail competition in making its decision on excluding the competition allowance. They stated that an observation of continued discounted market offers was insufficient evidence of the state of retail competition.[207] This view was further conveyed in retailer workshops, with retailers noting that many acquisition offers are typically loss-making. Therefore, they are not a suitable metric for the state of retail competition. Red Energy and Lumo Energy encouraged the AER to monitor the impact of the decision to exclude the competition allowance on the broader retail market.[208]

The AEC and AGL requested the AER provide further guidance on the process for considering whether the competition allowance will be re-introduced in future determinations.[209] Similarly, Origin Energy supported the use of underlying CPI inflation as a stable measure, but requested further clarification on the application of the ‘material and sustained’ nature of elevated inflation.[210] In workshops, retailers requested the AER consider the objective of the competition allowance and its role in facilitating consumer engagement in the energy market.

9.3 Final determination

9.3.1 Quantifying the competition allowance

For the DMO 7 final determination we have calculated competition allowance values that would allow retailers serving 90% of customers to make a reasonable profit. This results in a competition allowance of $22.61 for residential customers and $26.19 for small business customers, excluding GST.

We acknowledge that the magnitude of competition allowance values determined for DMO 7 represent a material departure from the values determined, but not included, in DMO 6. In

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205 AEC, Submission to DMO 7 draft determination, Australian Energy Council, 8 April 2025, p. 1; ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 5; Alinta Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 4; 1st Energy, Submission to DMO 7 draft determination, 1 April 2025, p. 3.

206 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 3; Powershop/Shell Energy, Submission to DMO 7 draft determination, 4 April 2025, p. 4.

207 ENGIE, Submission to DMO 7 draft determination, 3 April 2025, p. 6; Energy Locals, Submission to DMO 7 draft determination, 3 April 2025, p. 2.

208 Red Energy and Lumo Energy, Submission to DMO 7 draft determination, 3 April 2025, p. 3.

209 AEC, Submission to DMO 7 draft determination, Australian Energy Council, 8 April 2025, p. 1; AGL, Submission to DMO 7 draft determination, 7 April 2025, p. 4.

210 Origin Energy, Submission to DMO 7 draft determination, 8 April 2025, p. 7.

the DMO 6 final determination we stated that it was not possible to provide detail on the methodology used for quantifying the competition allowance given doing so could risk the confidentiality of the retail cost information used in the methodology. Accordingly, it is not possible to provide a detailed description of how the methodology in DMO 7 differs from the one used in DMO 6.

For DMO 7 we used information gathered via our own information requests and did not rely on information gathered by the ACCC inquiry. This incorporates an additional 13 retailers approximately serving a cumulative 5% market share, many of which do not exhibit the cost efficiencies demonstrated by larger retailers. This has allowed us to take a wider view of the spread of retail costs across retailers compared with what was possible with the data available for DMO 6. It has also enabled us to take a more granular approach to determining a benchmark cost to serve, which would form the basis for the competition allowance.

As noted in our draft determination, while there is a large spread in the range of costs to serve across the new retailers included in our data gathering, the weighted average of this cohort is greater than the weighted average for all retailers.[211]

We consider that setting the competition allowance to accommodate the costs to serve of retailers selling to 90% of customers in DMO regions contributes to achieving the DMO objective of incentivising competition because a significant proportion of retailers could achieve a reasonable profit. It also avoids the competition allowance being excessively large due to the impact of more inefficient retailers, which would be inconsistent with the DMO pricing protection objectives.

9.3.2 Including or excluding the competition allowance

Affordability concerns are a relevant consideration in the DMO and we have determined that it is appropriate to continue to address these by including or excluding the competition allowance.

The primary factor we have had regard to when determining whether to include the competition allowance for DMO 7 are 12-month movements in trimmed mean CPI, reported on quarterly by the ABS. In this regard, we note concern from some stakeholders that selection of trimmed mean CPI (as opposed to headline CPI) did not promote transparency or regulatory certainty.

We consider that trimmed mean CPI is the more appropriate measure to gauge cost-of-living pressures because it minimises distortions by removing the more volatile items from the calculation of CPI, including those that both temporarily increase or decrease headline CPI. The RBA considers that measures of underlying inflation such as trimmed mean CPI are more likely than headline inflation to reflect inflationary pressures, and that evidence shows that headline inflation tends to move towards the trimmed mean, while the reverse is not true.[212]

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211 AER, DMO 7 draft determination, Australian Energy Regulator, 13 March 2025, p. 70.

212 Reserve Bank of Australia, Statement on Monetary Policy, August 2024, p. 60.

On 30 April 2025 the ABS issued annual CPI movements for the March 2025 quarter.[213] The update notes that trimmed mean inflation has fallen to 2.9%, down from the 3.3% in the December quarter data that was used to inform our draft determination. This is the first time that underlying inflation has fallen within the RBA target band of 2% to 3%, after sitting above this range for 12 consecutive quarters.

In assessing forecasts of economic conditions, our draft determination had regard to the RBA's February 2025 Statement on Monetary Policy, which noted that underlying CPI inflation was forecast to fall, and stay within, the target band in 2025. On 20 May 2025, the RBA released the May 2025 Statement on Monetary Policy. The RBA note that inflationary pressures have continued to ease, with the outlook for domestic inflation being revised down since the February Statement on Monetary Policy. However, they also note that this is dependent on developments in international trade policy, the impacts of which are highly uncertain. The RBA considers elevated global and domestic uncertainty persists in its baseline forecast[214] and notes that Australian economic policy uncertainty has increased.[215]

Therefore, while we note that underlying CPI has fallen marginally within the target band, we consider the sustained nature of elevated CPI inflation prior to the March 2025 quarter, along with uncertainty over economic forecasts, do not provide sufficient evidence that cost-of-living pressures have eased at this time. Therefore, we have determined to not include the competition allowance for the DMO 7 final determination.

In making this determination, we acknowledge concerns of retailers about the transparency of our decision-making framework and accept our decision reflects a degree of regulatory judgement given the March 2025 quarter update on underlying inflation. In this regard, we note the following:

- While we have regard to objective metrics to inform our decision-making (in this case, trimmed mean CPI), we consider it necessary to retain a degree of regulatory discretion to balance all other relevant factors, some of which may not be captured by objective metrics.
- We are aiming to create an enduring framework regarding the inclusion of the competition allowance. While the March 2025 quarter update does not yet offer conclusive evidence of relief from cost-of-living pressures, a sustained decline in underlying inflation across successive quarters would offer a more compelling basis for future DMO determinations.
- We would hold this view if the inverse situation was true. If inflation was persistently within the RBA target band for several successive quarters or years, we would not necessarily consider a single quarter of CPI above the RBA target band sufficient evidence to exclude the competition allowance.

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213 Australian Bureau of Statistics (March quarter 2025), Consumer Price Index, Australia, ABS Website, accessed May 2025.

214 RBA, May 2025 Statement on Monetary Policy, Reserve Bank of Australia, May 2025, p. 56.

215 RBA, May 2025 Statement on Monetary Policy, Reserve Bank of Australia, May 2025, p. 29.

We consider the decision to exclude the competition allowance is consistent with the requirement to have regard to retailers' ability to make a reasonable profit.[216] As discussed in chapter 7, the weighted average retail and other costs included in the DMO price allows retailers selling to 78% of residential and 64% of small business customers to recover costs and achieve a reasonable profit without the inclusion of the competition allowance.

We do not consider the exclusion of the competition allowance will unduly restrict competition, given 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.

Further, 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 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 note concerns from some retailers that evaluation of discounted market offers may not be a suitable metric for assessing whether the exclusion of the competition allowance in DMO 6 has impacted retail competition.

However, we also note during 2024–25:

- continued growth of many small and medium retailers and gradual declines in the collective market share of Tier 1 retailers
- 2 entities are undergoing applications for authorisations to sell electricity[217]
- 2 retailers were approved by the AER to sell electricity, indicating new participants continue to enter the market[218]
- continued customer engagement in the market with further reductions in the proportions of customers on standing offers.

We consider this provides reasonable evidence that the exclusion of the competition allowance from DMO 6 prices has not harmed retail competition.

216 Regulations, s. 16(4)(b).

217 AER, CEP Energy Retail Pty Ltd – Application for electricity retailer authorisation, Australian Energy Regulator, 28 January 2025; Banpu Energy Australia Pty Limited – Application for electricity retailer authorisation, 9 April 2025.

218 AER, Flipped Energy Australia – authorised electricity retailer, Australian Energy Regulator, 26 September 2024; AER, Euroka Energy Pty Ltd – authorised electricity retailer, Australian Energy Regulator, 6 September 2024.

9.4 Summary of determinations for the competition allowance

The final determination adopts the same approach as the draft determination to calculating competition allowances that reflect the range of costs to serve among retailers covering 90% market share. Under this approach, the 2025–26 amount would be $22.61 for residential customers and $26.19 for small business customers (excl. GST).

However, as a result of economic and market conditions as at March 2025, our final determination is that the competition allowance will not be applied to DMO 7.

10 Annual usage amounts, and timing and pattern of supply

- The DMO 7 final determination retains the annual usage benchmarks from DMO 6 for residential and small business customers, including the current controlled load amounts.
- We will retain our approach from DMO 6 for calculating the timing and pattern of supply, updating the usage profiles with new AEMO interval meter data.

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. Throughout this document we refer to annual supply as annual usage.

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

10.1 Draft determination

10.1.1 Annual usage amounts

In our draft determination we had regard to stakeholder submissions to the issues paper, the available information from the ACCC June 2024 Inquiry report[219] and DNSP consumption data. We considered the annual usage amounts were still broadly representative of residential and small business customer usage. Our draft determination retained the annual usage amounts from DMO 6 for residential and small business customers, including the current controlled load amounts.

10.1.2 Timing and pattern of supply

In our draft determination we had regard to stakeholder submissions to the issues paper and interval meter data from AEMO. We decided to maintain the existing approach from DMO 6 with updated usage profiles based on current AEMO interval meter data. The timing and pattern of supply continued to be based on residential time of use profiles, because small business customers have widely varying consumption patterns. We noted that further engagement with AEMO, network businesses and meter providers was required to accurately remove controlled load from the time of use pattern in future determinations.

10.2 Stakeholder views

10.2.1 Annual usage amounts

No submissions to our draft determination discussed annual usage amounts.

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219 ACCC, Inquiry into the National Electricity Market report - June 2024, Australian Competition and Consumer Commission, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report.

10.2.2 Timing and pattern of supply

No submissions to our draft determination discussed time of use consumption patterns.

10.3 Final determination

10.3.1 Annual usage amounts

The DMO 7 final determination retains the annual usage benchmarks from DMO 6 for residential and small business customers, including the controlled load amounts. The per-customer annual usage determination is set out in Appendix C.

Having regard to the most recent available information on annual usage sourced from the ACCC June 2024 Inquiry report[220] and data collected from DNSPs, and set out in our draft determination,[221] we consider the amounts remain broadly representative of residential and small business customer usage.

10.3.2 Timing and pattern of supply

The DMO 7 final determination retains our approach to timing and pattern of supply used for DMO 6 and uses updated usage profiles sourced from new AEMO interval meter data.

We have determined that our approach from DMO 6 remains the most appropriate method to calculate a representative time of use profile due to limitations of the underlying Market Settlement and Transfer Solutions (MSATS) data and data provided by network businesses. We have updated the time of use consumption profiles based on the most recent interval meter data from AEMO. We retained our assumptions, and the reasoning on which we make these assumptions, from prior determinations because it remains broadly reflective of a time of use patterns in each region.

In summary, we have:

- assumed the same usage occurs every day (with no variation for weekday, weekend or season), as in previous determinations
- used the same proportional allocations of annual controlled load usage across multiple controlled loads
- retained a single 24-hour usage profile
- updated profiles using the AEMO interval meter data for each region, averaged over 3 years
- specified 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).

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220 ACCC, Inquiry into the National Electricity Market report - June 2024, Australian Competition and Consumer Commission, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report.

221 AER, DMO 7 draft determination, Australian Energy Regulator, 13 March 2025, p. 93–96.

For the reasons set out in our draft determination,[222] we will continue to engage with AEMO, network businesses and meter providers to understand the most accurate approach to removing controlled load from the MSATS data in future determinations.

222 AER, DMO 7 draft determination, Australian Energy Regulator, 13 March 2025, pp. 96–97.

11 Appendices

Appendix A – Listening report

Appendix B – Smart meter costs

Appendix C – DMO Legislative Instrument 2025–26

Appendix D – DMO 6 to DMO 7 price movements

Appendix E – State-based summaries of cost changes

A. Listening report

AUSTRALIAN ENERGY REGULATOR

26 May 2025

DMO 7 Listening Report

Moving from draft determination to final determination

Our engagement process for DMO 7 involved undertaking targeted consultation activities with a range of key stakeholders.

We publicly invited written submissions, conducted one-on-one meetings, presented to consumer representatives and facilitated online workshops with retailers to listen to and discuss stakeholders' perspectives on our draft determination published in March 2025. The consultation approach for DMO 7 has:

- allowed the AER to directly listen to key stakeholders' views before receiving written submissions
- allowed stakeholders to ask questions of AER staff before writing submissions
- provided an opportunity for stakeholders who choose not to provide a written submission to have input into our DMO methodology considerations
- ensured our rationale and decision-making process is transparent.

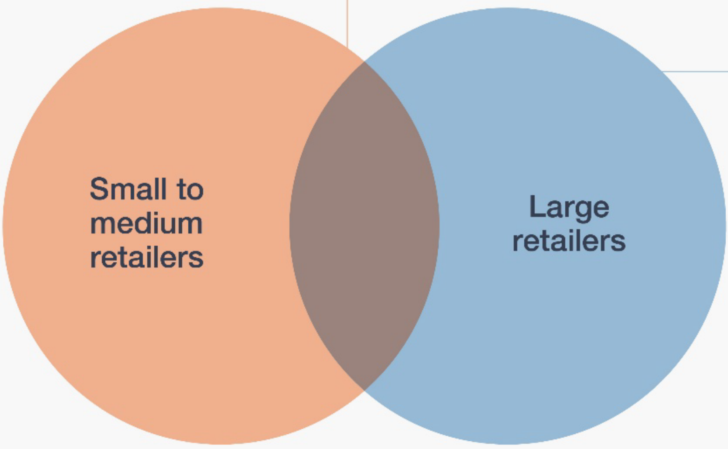
The topics presented in this Listening Report represent the verbal stakeholder feedback received during one-on-one meetings and group discussions in March and April 2025. The issues presented do not represent the written submissions that have been included in the DMO 7 draft determination and published on our website.

Engagement timeline since draft determination

13 March 2025	Draft determination published for consultation
26–27 March	Online group meetings with retailer and consumer advocacy groups
17 March 2025 – 3 April 2025	One-on-one meetings with industry, and consumer advocacy groups
30 April 2025	Extended consultation on retail costs
26 May 2025	Final determination published

Wholesale

Solar exports and hedging adjustment



Small to medium retailers

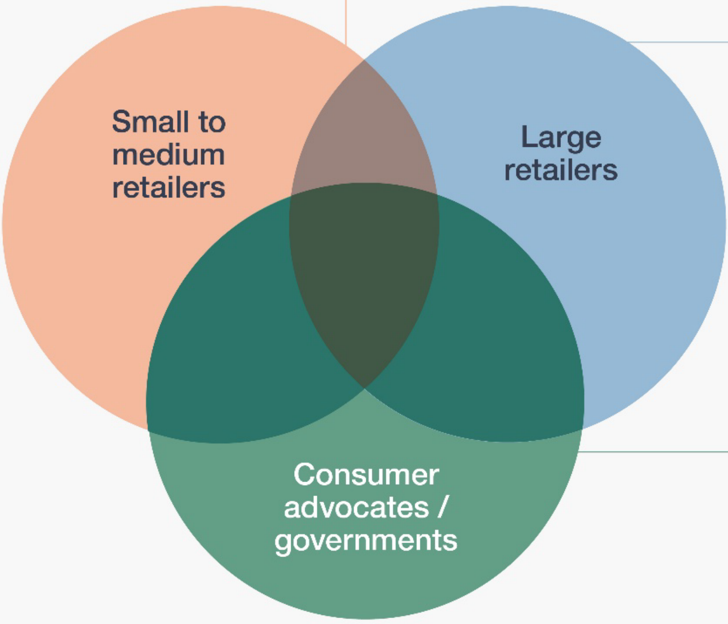
- Did not support the decision to exclude solar exports from the load profiles.
- Solar penetration is considered extremely significant and driven by government policy. The value of feed-in tariffs is declining.
- Retailers face a significant cost exposure when they're a net exporter during negative price intervals. There are no hedging products to cover this.

Large retailers

- The change in the hedging strategy resulting from the hedging adjustment is overshadowed by more fundamental assumptions in the wider hedging strategy.
- The fluctuating nature of the adjustment's contribution to total wholesale costs was unexpected.

Retail

Retail costs



Small to medium retailers

- Supported the expanded retailer dataset but disagreed with the customer weighted average approach to calculate retail costs. Instead recommended a median approach to be more reflective of smaller retailer cost structures.

Large retailers

- Supported the expanded retailer dataset and encouraged the AER to maintain position on moving forward.

Retailer agreement

- The expanded retailer dataset is more reflective of the varied cost structures among retailers and promotes competition.

Consumer advocates/groups

- A broader retailer dataset will increase retail costs and may not account for the costs of a prudent retailer and promote efficiency.
- The methodology for how the cost to acquire and retain customers and bad and doubtful debt costs are assessed needs to be improved to protect consumers.

75th percentile estimate of modelled wholesale cost outcomes

- Retailers noted various aspects of the draft determination that resulted in downward pressure on DMO prices, such as maintaining the 75th percentile and the inclusion of a solar adjustment causing a reduction in the wholesale energy cost in some regions.
- Retailers strongly encouraged the 95th percentile to be reconsidered to account for risks and volatility faced by retailers.

Competition allowance

- Retailers had mixed views around the AER's decision to benchmark the trimmed mean CPI to the competition allowance considering recent announcements of further energy bill relief by the Australian Government.
- Retailers suggested that the consideration of the trimmed mean inflation was not consistent with previous positions. Retailers also questioned whether it is within the AER's remit to consider cost-of-living when assessing the competition allowance.
- There was a common consensus from industry that further clarification is required around the pre-conditions on the inclusion of the competition allowance.
- Consumer groups advocated for the removal of the competition allowance, on the basis that this should already be accounted for in the retail margin component.

Thank you for your feedback

15 stakeholders spoken to through online workshops and one-on-one meetings

17 written submissions received

+4 additional retail costs submissions received

9 retailers attended 2 separate workshops, accounting for over 90% of residential and small business customers across NSW, SE Queensland and South Australia

10 one-on-one meetings

Other feedback received

We consulted on a broad range of topics verbally where we also heard:

- Consumer group stakeholders advocated for policy-level changes to the DMO
- Consumer groups raised concerns around different retail margins for residential and small business customers
- Concerns around using a flat network tariff approach considering the upcoming AEMC rule change
- Support for a blended network cost approach in future DMO determinations
- Support for our current approach for environmental costs
- Support for the use of AEMO's historical Controlled Load Profile to simulate the controlled load profile in NSW for DMO 7

Written feedback

We invited stakeholders to publicly contribute to our consultation process, and received 17 written submissions from:

- 1st Energy
- ActewAGL
- AGL
- Alinta Energy
- Australian Energy Council
- Energy Consumers Australia
- Energy Locals
- EnergyAustralia
- ENGIE
- The Hon Penny Sharpe MLC
- Jason Page
- Justice and Equity Centre, South Australian Council of Social Service, Australian Council of Social Service, Queensland Council of Social Service
- Origin Energy
- Red Energy and Lumo Energy
- South Australian Business Chamber
- South Australian Department for Energy and Mining
- Powershop/Shell Energy Australia

How we collected feedback

1 consumer group presentation held with the AER's Customer Consultative Group	**2** retailer workshops grouped by size, involving 9 participants	**10** one-on-one meetings with stakeholders

Our continued engagement

We value the contributions of all stakeholders that provided feedback during the consultation process for our DMO 7 draft determination. We will continue our stakeholder engagement activities as part of our DMO process in future determinations.

The final determination outlines how we considered stakeholder feedback and includes our rationale behind each component of the final determination.

We would like to thank participants for their involvement in this process and look forward to further positive engagement in the future.

Australian Government

AUSTRALIAN ENERGY REGULATOR

B. Smart meter costs

We requested retailers selling to approximately 94% of customers in DMO regions to provide the number of customers on advanced meters and accumulation meters for each DMO region and customer type as at 31 March 2025, and projected installations for the mid-point of DMO 7 (31 December 2025). We also asked retailers to provide the average costs they incur per advanced meter and the extent to which a portion of these costs are recovered in up-front and/or one-off installation fees. Tables B.1 and B.2 set out our calculations for estimating advanced meter costs per residential and small business customer.

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

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	$72,208,006	$68,828,003	$52,794,060	$84,349,884	$50,322,503	$328,502,457
Total advanced meter customers	618,939	580,814	417,695	717,418	425,702	2,760,568
Average cost incurred per advanced meter ($) (excl. GST)	$116.66	$118.50	$126.39	$117.57	$118.21	$119.00
ACS metering allowance included in network component ($) (excl. GST)	$27.54	N/A				
Proportion of customers that do not incur an ACS charge (new connections with smart meters) (%)	6.96%	N/A				
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-$1.92	N/A				
Total customers	1,520,355	951,201	740,003	1,354,686	798,124	5,364,369
Customers with advanced meters (%)	40.7%	61.1%	56.4%	53.0%	53.3%	51.5%
Advanced meter cost per customer ($)	$45.58	$72.36	$71.34	$62.27	$63.05	N/A
Additional capital allowance adjustment (see Table B.3)	$1.65	$2.21	$2.76	$2.64	$1.94	N/A

N/A: Data not applicable.
Source: Retailer data request as at 31 March 2025.

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

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	$4,867,407	$3,396,399	$4,139,203	$5,722,150	$4,098,513	$22,223,672
Total advanced meter customers	38,120	25,426	29,560	39,704	29,755	162,565
Average cost incurred per advanced meter ($) (excl. GST)	$127.69	$133.58	$140.03	$144.12	$137.74	$136.71
ACS metering allowance included in network component ($) (excl. GST)	$38.16	N/A				
Proportion of customers that do not incur an ACS charge (new connections with smart meters) (%)	21.61%	N/A				
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-$8.25	N/A				
Total customers	133,915	64,943	72,939	99,579	79,094	450,470
Customers with advanced meters (%)	28.5%	39.2%	40.5%	39.9%	37.6%	36.1%
Advanced meter cost per customer ($)	$28.10	$52.30	$56.75	$57.46	$51.82	N/A
Additional capital allowance adjustment (see Table B.3)	$1.94	$3.76	$4.35	$4.51	$2.02	N/A

N/A: Data not applicable.
Source: Retailer data request as at 31 March 2025

Table B.3 Calculation of residential capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 7, based on actual installs at 31 March 2025	$45.58	$72.36	$71.34	$62.27	$63.05
Smart meter allowance based on retailer projected installations at 31 December 2025	$62.04	$94.51	$98.97	$88.68	$82.46
Projected shortfall in smart meter allowance at 31 December 2025	$16.46	$22.15	$27.63	$26.42	$19.41
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)	$1.65	$2.21	$2.76	$2.64	$1.94

Source: Retailer data request as at 31 March 2025

Table B.4 Calculation of small business capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 7, based on actual installs at 31 March 2025	$28.10	$52.30	$56.75	$57.46	$51.82
Smart meter allowance based on retailer projected installations at 31 December 2025	$47.55	$89.89	$100.21	$102.54	$72.06
Projected shortfall in smart meter allowance at 31 December 2025	$19.45	$37.59	$43.47	$45.07	$20.24
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)	$1.94	$3.76	$4.35	$4.51	$2.02

Source: Retailer data request as at 31 March 2025

C. DMO Legislative Instrument 2025–26

Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2025

The Australian Energy Regulator makes the following determination.

Dated 26 May 2025 Australian Energy Regulator

1. Name

This instrument is the *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2025.*

2. Commencement

This instrument commences on 1 July 2025.

3. Authority

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

4. Definitions

In this Determination:

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

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

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

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

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

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

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

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

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

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

5. Per-customer usage determination

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

Per-customer annual usage determination (365 days p.a. in 2025-26)				
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)	**0.2426**	**0.2352**	**0.2227**	**0.1973**	**0.1787**	**0.1630**	**0.1523**	**0.1457**	**0.1431**	**0.1430**	**0.1482**	**0.1570**	**0.1738**	**0.1948**	**0.2050**	**0.2158**	**0.2168**	**0.2136**	**0.2113**	**0.2079**	**0.2062**	**0.2035**	**0.2015**	**0.2013**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2022**	**0.2022**	**0.2014**	**0.2007**	**0.2006**	**0.2022**	**0.2061**	**0.2160**	**0.2298**	**0.2483**	**0.2701**	**0.2968**	**0.3123**	**0.3168**	**0.3120**	**0.3048**	**0.2996**	**0.2932**	**0.2821**	**0.2705**	**0.2668**	**0.2645**	**0.2575**	**0.2479**

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)	**0.2986**	**0.2895**	**0.2741**	**0.2428**	**0.2199**	**0.2006**	**0.1875**	**0.1793**	**0.1762**	**0.1760**	**0.1824**	**0.1932**	**0.2140**	**0.2398**	**0.2523**	**0.2656**	**0.2668**	**0.2628**	**0.2601**	**0.2559**	**0.2538**	**0.2505**	**0.2480**	**0.2478**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2489**	**0.2489**	**0.2478**	**0.2470**	**0.2468**	**0.2489**	**0.2536**	**0.2659**	**0.2828**	**0.3056**	**0.3325**	**0.3653**	**0.3844**	**0.3900**	**0.3841**	**0.3751**	**0.3688**	**0.3608**	**0.3472**	**0.3329**	**0.3284**	**0.3256**	**0.3170**	**0.3051**

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)	**0.3197**	**0.3125**	**0.2877**	**0.2475**	**0.2191**	**0.1990**	**0.1870**	**0.1813**	**0.1806**	**0.1813**	**0.1888**	**0.1999**	**0.2195**	**0.2438**	**0.2487**	**0.2586**	**0.2584**	**0.2531**	**0.2534**	**0.2519**	**0.2499**	**0.2487**	**0.2471**	**0.2474**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2473**	**0.2466**	**0.2452**	**0.2470**	**0.2513**	**0.2565**	**0.2657**	**0.2837**	**0.3044**	**0.3319**	**0.3551**	**0.3868**	**0.4017**	**0.4043**	**0.3973**	**0.3884**	**0.3772**	**0.3642**	**0.3474**	**0.3257**	**0.3257**	**0.3331**	**0.3289**	**0.3242**

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)	**0.3393**	**0.3316**	**0.3054**	**0.2626**	**0.2326**	**0.2112**	**0.1984**	**0.1924**	**0.1916**	**0.1924**	**0.2003**	**0.2121**	**0.2330**	**0.2588**	**0.2639**	**0.2745**	**0.2742**	**0.2686**	**0.2690**	**0.2674**	**0.2652**	**0.2639**	**0.2622**	**0.2626**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2625**	**0.2617**	**0.2602**	**0.2622**	**0.2667**	**0.2722**	**0.2820**	**0.3011**	**0.3230**	**0.3522**	**0.3769**	**0.4105**	**0.4262**	**0.4291**	**0.4216**	**0.4121**	**0.4003**	**0.3865**	**0.3686**	**0.3456**	**0.3457**	**0.3535**	**0.3491**	**0.3441**

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)	**0.2085**	**0.1935**	**0.1837**	**0.1741**	**0.1665**	**0.1614**	**0.1587**	**0.1578**	**0.1605**	**0.1663**	**0.1761**	**0.1887**	**0.2099**	**0.2301**	**0.2450**	**0.2482**	**0.2474**	**0.2423**	**0.2409**	**0.2393**	**0.2404**	**0.2478**	**0.2539**	**0.2592**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2586**	**0.2583**	**0.2581**	**0.2571**	**0.2605**	**0.2647**	**0.2741**	**0.2902**	**0.3090**	**0.3351**	**0.3656**	**0.3994**	**0.4169**	**0.4189**	**0.4043**	**0.3884**	**0.3769**	**0.3572**	**0.3348**	**0.3145**	**0.2977**	**0.2768**	**0.2552**	**0.2300**

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)	**0.1995**	**0.1851**	**0.1757**	**0.1665**	**0.1593**	**0.1544**	**0.1518**	**0.1509**	**0.1535**	**0.1591**	**0.1685**	**0.1805**	**0.2008**	**0.2201**	**0.2343**	**0.2374**	**0.2366**	**0.2318**	**0.2304**	**0.2289**	**0.2300**	**0.2371**	**0.2428**	**0.2479**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2473**	**0.2471**	**0.2469**	**0.2459**	**0.2491**	**0.2532**	**0.2622**	**0.2776**	**0.2956**	**0.3206**	**0.3497**	**0.3820**	**0.3987**	**0.4007**	**0.3867**	**0.3715**	**0.3605**	**0.3416**	**0.3202**	**0.3008**	**0.2848**	**0.2648**	**0.2441**	**0.2200**

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)	**0.2892**	**0.2811**	**0.2684**	**0.2540**	**0.2373**	**0.2169**	**0.2003**	**0.1899**	**0.1840**	**0.1831**	**0.1910**	**0.2036**	**0.2246**	**0.2417**	**0.2474**	**0.2519**	**0.2460**	**0.2339**	**0.2334**	**0.2314**	**0.2294**	**0.2328**	**0.2343**	**0.2338**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2361**	**0.2316**	**0.2256**	**0.2202**	**0.2184**	**0.2198**	**0.2263**	**0.2383**	**0.2539**	**0.2754**	**0.3077**	**0.3468**	**0.3713**	**0.3769**	**0.3686**	**0.3571**	**0.3500**	**0.3406**	**0.3305**	**0.3212**	**0.3240**	**0.3156**	**0.3061**	**0.3013**

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)	**0.2892**	**0.2811**	**0.2684**	**0.2540**	**0.2373**	**0.2169**	**0.2003**	**0.1899**	**0.1840**	**0.1831**	**0.1910**	**0.2036**	**0.2246**	**0.2417**	**0.2474**	**0.2519**	**0.2460**	**0.2339**	**0.2334**	**0.2314**	**0.2294**	**0.2328**	**0.2343**	**0.2338**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2361**	**0.2316**	**0.2256**	**0.2202**	**0.2184**	**0.2198**	**0.2263**	**0.2383**	**0.2539**	**0.2754**	**0.3077**	**0.3468**	**0.3713**	**0.3769**	**0.3686**	**0.3571**	**0.3500**	**0.3406**	**0.3305**	**0.3212**	**0.3240**	**0.3156**	**0.3061**	**0.3013**

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)	**0.2327**	**0.2720**	**0.2979**	**0.2782**	**0.2418**	**0.2110**	**0.1845**	**0.1683**	**0.1573**	**0.1529**	**0.1547**	**0.1624**	**0.1796**	**0.1875**	**0.2086**	**0.1980**	**0.1907**	**0.1808**	**0.1764**	**0.1888**	**0.2055**	**0.2312**	**0.2407**	**0.2344**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2272**	**0.2154**	**0.2074**	**0.2018**	**0.2022**	**0.2025**	**0.2070**	**0.2070**	**0.2233**	**0.2387**	**0.2726**	**0.3076**	**0.3277**	**0.3320**	**0.3274**	**0.3205**	**0.3115**	**0.2991**	**0.2824**	**0.2610**	**0.2367**	**0.2117**	**0.1918**	**0.2084**

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)	**0.2443**	**0.2856**	**0.3128**	**0.2921**	**0.2539**	**0.2216**	**0.1937**	**0.1767**	**0.1651**	**0.1606**	**0.1625**	**0.1705**	**0.1885**	**0.1969**	**0.2191**	**0.2079**	**0.2002**	**0.1898**	**0.1852**	**0.1982**	**0.2158**	**0.2428**	**0.2527**	**0.2461**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2385**	**0.2262**	**0.2178**	**0.2119**	**0.2123**	**0.2126**	**0.2174**	**0.2173**	**0.2345**	**0.2506**	**0.2863**	**0.3229**	**0.3441**	**0.3486**	**0.3437**	**0.3365**	**0.3271**	**0.3141**	**0.2965**	**0.2741**	**0.2485**	**0.2223**	**0.2014**	**0.2188**

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 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.0000**	**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)[223]

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

[223] 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 draft annual price determination (all prices GST-inclusive)			
Distribution region	**Annual Residential Price without Controlled Load**	**Annual Residential Price with Controlled Load**	**Small Business Annual Price**
Ausgrid	$1,965	$2,717	$4,977
Endeavour Energy	$2,411	$3,072	$4,775
Energex	$2,143	$2,425	$4,294
Essential Energy	$2,741	$3,211	$6,222
SA Power Networks	$2,301	$2,824	$5,541

DATED THIS 26 DAY OF
MAY 2025

Australian Energy Regulator

D. DMO 6 to DMO 7 price movements

The charts in this appendix show the movement in the DMO cost components between the DMO 6 and DMO 7 final determinations, with the overall height indicating the total DMO price for each DNSP.

We note that:

- Network and environmental cost components in the DMO 7 final determination are calculated using predominantly the same methodology as DMO 6, so the changes directly reflect year-on-year movement.
- Changes to the retail cost component reflect both year-on-year movement and the impact of a broader retailer cost dataset that covers 99% of the small customer market.
- Changes to the wholesale cost component reflect both year-on-year movement and the impact of using one year of NSLP data to simulate the load profiles, instead of 2 years as used in previous DMO determinations.
  - For DMO 6 we also used the 'midpoint' of 2 load profiles in Energex and SA Power Networks, due to challenges with load profile data.

Figure D.1 Residential without controlled load, % change from DMO 6 (nominal)

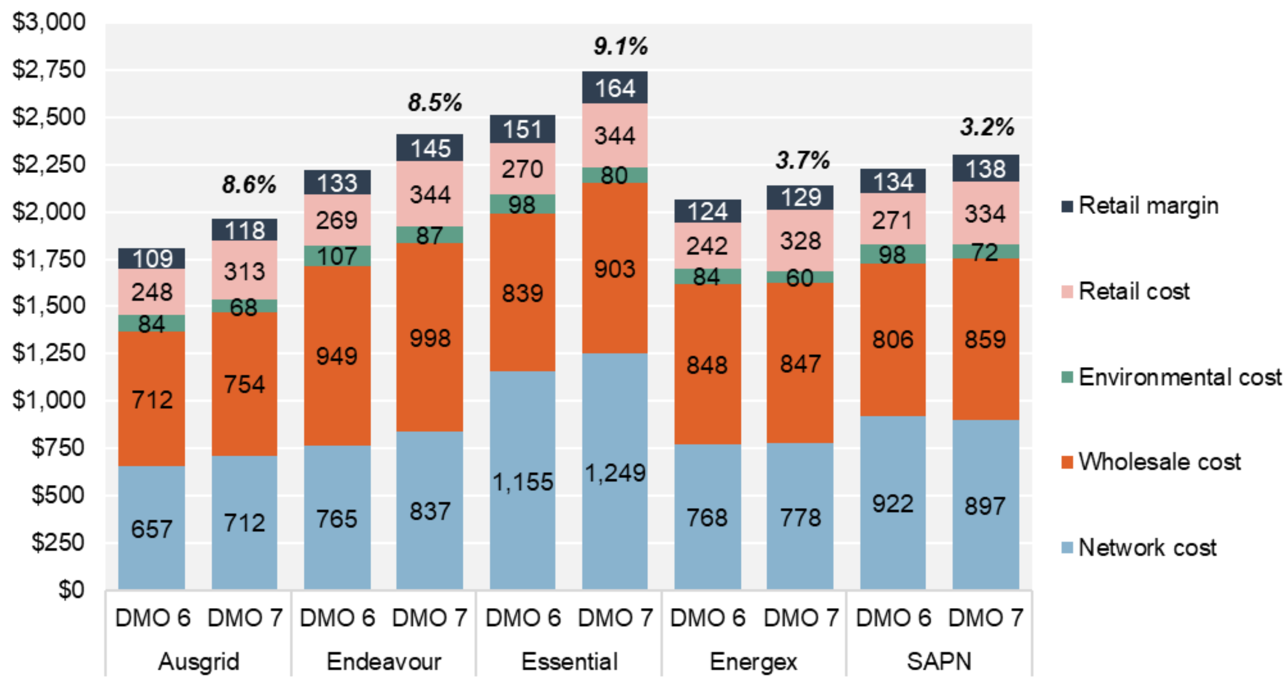


Figure D.2 Residential with controlled load, % change from DMO 6 (nominal)

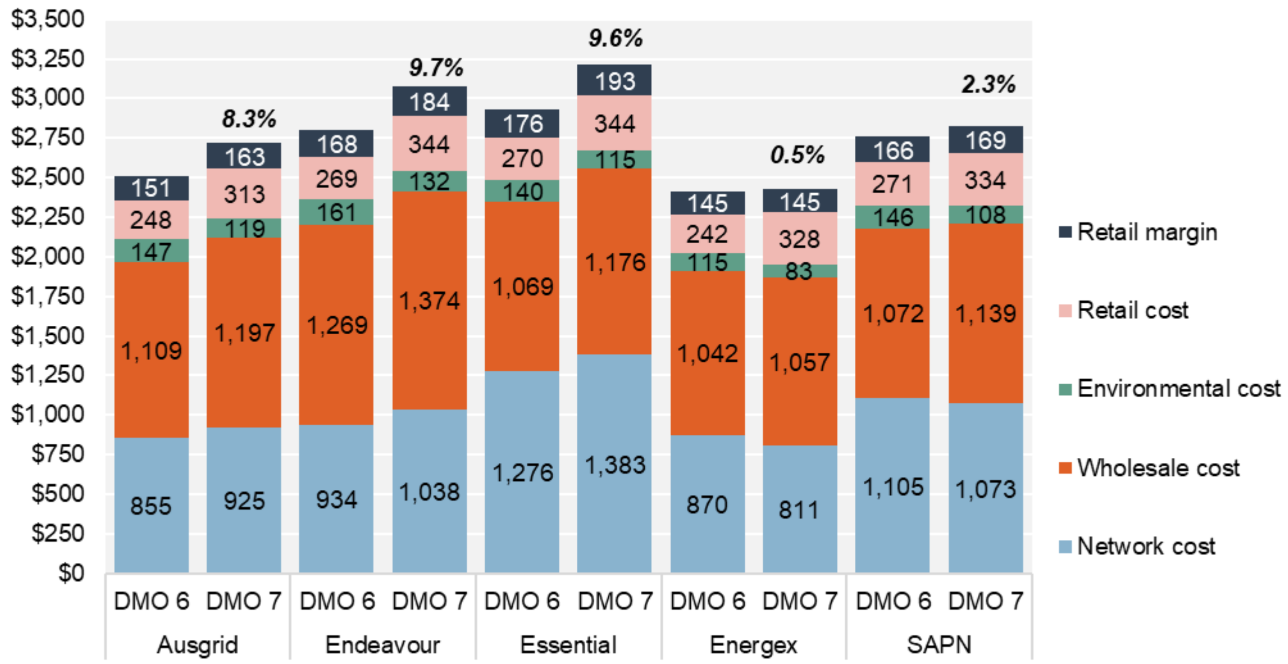
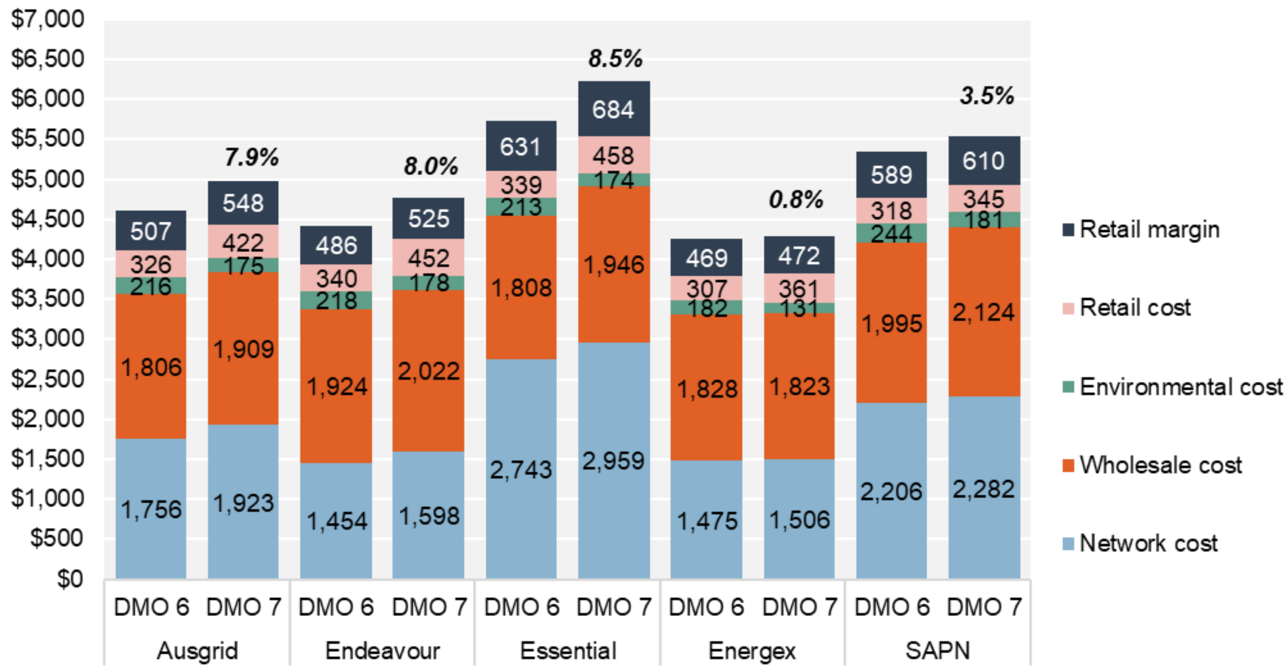


Figure D.3 Small business, % change from DMO 6 (nominal)



E. State-based summaries of cost changes

This appendix explains in detail the DMO cost stack changes from the DMO 6 final determination to the DMO 7 draft and final determinations for each state.

NSW summary

NSW **residential customers without controlled load** will see price increases of $155 or 8.6% (Ausgrid), $188 or 8.5% (Endeavour Energy) and $228 or 9.1% (Essential Energy). These increases are between 6.1% and 6.7% above forecast inflation.

Residential customers with controlled load will see price increases of $208 or 8.3% (Ausgrid), $271 or 9.7% (Endeavour Energy) and $280 or 9.6% (Essential Energy). These are increases of between 5.9% and 7.3% above forecast inflation.

Small business customers will see increases of $365 or 7.9% (Ausgrid), $353 or 8.0% (Endeavour Energy) and $489 or 8.5% (Essential Energy). These are increases of between 5.5% and 6.1% above forecast inflation.

As outlined in Tables E.1 to E.3, since the DMO 6 final determination we have observed:

- Across each region of NSW there have been increases in wholesale costs for all customer types, largely driven by movements in contract prices. Specific contract price movements for 2025–26 on an annualised and trade-weighted basis were increases in base futures contract prices of $8.80/MWh and in cap contract prices of $7.40/MWh. Increases in contract prices were partially offset by a slight flattening of load profiles in NSW regions, which reduced hedging costs.
- Across each region of NSW network costs have risen. Increases in network costs for NSW customers are driven by the price paths set in our 2024–29 regulatory determinations, with a key driver across each of these determinations being market factors (higher actual inflation and interest rates). Our determinations also included expenditure in important emerging areas such as improved network resilience to address climate change-related risks, the uptake and integration of consumer energy resources (including rooftop solar, batteries and electrical vehicles), and cyber security and digitalisation measures. In making our revenue determinations, we assess these expenditure proposals to ensure consumers pay no more than necessary for a safe and reliable power supply. The determined NSW Roadmap cost increases and higher transmission costs are also contributing to increases. However, forecast increasing energy consumption acts to partially offset price increases for NSW customers.
- Environmental costs have decreased across each region of NSW and all customer types. These decreases are primarily driven by decreases in both federal and state renewable energy target schemes, offset slightly by an increase in the NSW peak demand reduction scheme cost.
- Retail costs have risen for all customers in each region of NSW, primarily due to increases in retailers’ operating costs. Increases in bad and doubtful debt costs and smart meter costs also contributed to the overall increases.
- The dollar value of the retail margin has increased in DMO 7 due to increases in wholesale, network and retail costs. The retail margin is set at 6% of the total DMO price for residential customers and 11% for small business customers, so increases in other components of the cost stack cause the retail margin to also increase.

Table E.1 Residential without CL, change from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Final determination DMO 7		Difference from DMO 6 to Draft DMO 7		Difference from DMO 7 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	656.75		719.64		711.92		62.88	9.6%	-7.71	-1.1%	55.17	8.4%
	Wholesale cost	712.34		742.23		753.97		29.89	4.2%	11.74	1.6%	41.63	5.8%
	Environmental cost	84.26		69.93		68.33		-14.33	-17.0%	-1.60	-2.3%	-15.92	-18.9%
	Retail cost	248.17		318.76		312.51		70.59	28.4%	-6.25	-2.0%	64.34	25.9%
	Retail margin	108.61	6.0%	118.12	6.0%	117.88	6.0%	9.51	8.8%	-0.24	-0.2%	9.27	8.5%
	Total	**1,810**		**1,969**		**1,965**		**159**	**8.8%**	**-4**	**-0.2%**	**155**	**8.6%**
Endeavour Energy	Network cost	764.81		841.49		836.51		76.67	10.0%	-4.98	-0.6%	71.69	9.4%
	Wholesale cost	949.36		974.34		998.46		24.98	2.6%	24.12	2.5%	49.10	5.2%
	Environmental cost	106.78		88.61		87.41		-18.16	-17.0%	-1.20	-1.4%	-19.37	-18.1%
	Retail cost	268.94		348.35		344.31		79.41	29.5%	-4.05	-1.2%	75.36	28.0%
	Retail margin	133.40	*6.0%*	143.80	*6.0%*	144.68	*6.0%*	10.40	7.8%	0.89	0.6%	11.28	8.5%
	Total	**2,223**		**2,397**		**2,411**		**174**	**7.8%**	**14**	**0.6%**	**188**	**8.5%**
Essential Energy	Network cost	1,155.09		1,243.71		1,248.98		88.62	7.7%	5.27	0.4%	93.89	8.1%
	Wholesale cost	838.81		882.30		903.45		43.49	5.2%	21.15	2.4%	64.64	7.7%
	Environmental cost	97.86		81.21		80.17		-16.65	-17.0%	-1.04	-1.3%	-17.69	-18.1%
	Retail cost	270.03		342.80		343.76		72.77	26.9%	0.96	0.3%	73.73	27.3%
	Retail margin	150.75	*6.0%*	162.77	*6.0%*	164.45	*6.0%*	12.01	8.0%	1.68	1.0%	13.70	9.1%
	Total	**2,513**		**2,713**		**2,741**		**200**	**8.0%**	**28**	**1.0%**	**228**	**9.1%**

Table E.2 Residential with CL, change from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Final determination DMO 7		Difference from DMO 6 to Draft DMO 7		Difference from DMO 7 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	854.76		928.49		925.13		73.73	8.6%	-3.36	-0.4%	70.37	8.2%
	Wholesale cost	1,108.68		1,181.83		1,197.17		73.15	6.6%	15.34	1.3%	88.50	8.0%
	Environmental cost	147.15		122.12		119.14		-25.03	-17.0%	-2.98	-2.4%	-28.01	-19.0%
	Retail cost	248.17		318.76		312.51		70.59	28.4%	-6.25	-2.0%	64.34	25.9%
	Retail margin	150.56	*6.0%*	162.84	*6.0%*	163.02	*6.0%*	12.28	8.2%	0.18	0.1%	12.46	8.3%
	Total	**2,509**		**2,714**		**2,717**		**205**	**8.2%**	**3**	**0.1%**	**208**	**8.3%**
Endeavour Energy	Network cost	934.14		1,042.86		1,037.55		108.72	11.6%	-5.31	-0.5%	103.41	11.1%
	Wholesale cost	1,268.54		1,341.73		1,373.96		73.19	5.8%	32.23	2.4%	105.43	8.3%
	Environmental cost	161.25		133.82		132.00		-27.43	-17.0%	-1.82	-1.4%	-29.25	-18.1%
	Retail cost	268.94		348.35		344.31		79.41	29.5%	-4.05	-1.2%	75.36	28.0%
	Retail margin	168.06	*6.0%*	182.99	*6.0%*	184.33	*6.0%*	14.93	8.9%	1.34	0.7%	16.27	9.7%
	Total	**2,801**		**3,050**		**3,072**		**249**	**8.9%**	**22**	**0.7%**	**271**	**9.7%**
Essential Energy	Network cost	1,276.37		1,375.56		1,383.26		99.19	7.8%	7.70	0.6%	106.88	8.4%
	Wholesale cost	1,068.76		1,149.11		1,176.01		80.35	7.5%	26.90	2.3%	107.25	10.0%
	Environmental cost	140.41		116.52		115.03		-23.89	-17.0%	-1.50	-1.3%	-25.38	-18.1%
	Retail cost	270.03		342.80		343.76		72.77	26.9%	0.96	0.3%	73.73	27.3%
	Retail margin	175.89	*6.0%*	190.47	*6.0%*	192.64	*6.0%*	14.58	8.3%	2.17	1.1%	16.75	9.5%
	Total	**2,931**		**3,174**		**3,211**		**243**	**8.3%**	**37**	**1.2%**	**280**	**9.6%**

Table E.3 Small business without CL, change from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Final determination DMO 7		Difference from DMO 6 to Draft DMO 7		Difference from DMO 7 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	1,756.19		1,929.35		1,923.34		173.16	9.9%	-6.02	-0.3%	167.15	9.5%
	Wholesale cost	1,806.03		1,882.53		1,909.46		76.50	4.2%	26.93	1.4%	103.43	5.7%
	Environmental cost	216.04		179.30		175.21		-36.74	-17.0%	-4.09	-2.3%	-40.83	-18.9%
	Retail cost	326.29		447.96		421.95		121.66	37.3%	-26.01	-5.8%	95.66	29.3%
	Retail margin	507.30	*11.0%*	548.66	*11.0%*	547.52	*11.0%*	41.35	8.2%	-1.14	-0.2%	40.22	7.9%
	Total	**4,612**		**4,988**		**4,977**		**376**	**8.2%**	**-11**	**-0.2%**	**365**	**7.9%**
Endeavour Energy	Network cost	1,453.95		1,611.61		1,597.55		157.66	10.8%	-14.06	-0.9%	143.60	9.9%
	Wholesale cost	1,923.84		1,974.71		2,021.84		50.87	2.6%	47.12	2.4%	97.99	5.1%
	Environmental cost	217.91		180.84		178.38		-37.07	-17.0%	-2.46	-1.4%	-39.53	-18.1%
	Retail cost	339.66		470.68		452.19		131.03	38.6%	-18.49	-3.9%	112.53	33.1%
	Retail margin	486.39	*11.0%*	523.78	*11.0%*	525.28	*11.0%*	37.39	7.7%	1.50	0.3%	38.88	8.0%
	Total	**4,422**		**4,762**		**4,775**		**340**	**7.7%**	**13**	**0.3%**	**353**	**8.0%**
Essential Energy	Network cost	2,742.78		2,951.28		2,959.14		208.49	7.6%	7.87	0.3%	216.36	7.9%
	Wholesale cost	1,808.12		1,902.55		1,946.16		94.43	5.2%	43.61	2.3%	138.04	7.6%
	Environmental cost	212.74		176.55		174.28		-36.19	-17.0%	-2.27	-1.3%	-38.46	-18.1%
	Retail cost	338.81		472.37		458.05		133.56	39.4%	-14.32	-3.0%	119.24	35.2%
	Retail margin	630.64	*11.0%*	680.11	*11.0%*	684.43	*11.0%*	49.47	7.8%	4.31	0.6%	53.79	8.5%
	Total	**5,733**		**6,183**		**6,222**		**450**	**7.8%**	**39**	**0.6%**	**489**	**8.5%**

Source: AER Default market offer 2025–26 cost assessment model.

SE Queensland summary

SE Queensland **customers without controlled load** face an overall price increase of $77 or 3.7% (1.3% above forecast inflation).

Customers with controlled load will face an increase of $11 or 0.5% (1.9% below forecast inflation).

Small business customers can expect an increase of $33 or 0.8% (1.6% below forecast inflation).

As outlined in Table E.4, since the DMO 6 final determination we have observed the following in SE Queensland:

- Small movements in wholesale costs depending on customer type, driven by movements in contract prices and 'other' wholesale costs, partially offset by a slight flattening of load profiles. Specific contract price movements for 2025–26 on an annualised and trade-weighted basis were increases in base futures contract prices of $4.60/MWh and in cap contract prices of $0.40/MWh. These slight increases in relevant contract prices resulted from significant volumes of base and cap contract purchases occurring at lower prices during 2023. These trades partially offset contracts purchased at higher prices throughout 2024 and early 2025.
- Network costs have increased for residential and small business customers without controlled load and decreased for residential customers with controlled load. The changes are driven by the price path in our 1 July 2025 to 30 June 2030 regulatory determination for Energex. The price path increase is largely due to a higher return on capital, which is driven by market factors (higher actual inflation and interest rates). Our determinations also included expenditure in important emerging areas such as improved network resilience to address climate change-related risks, the uptake and integration of consumer energy resources (including rooftop solar, batteries and electrical vehicles), mitigating the risks of the increasing frequency of extreme weather events and cyber security. In making our revenue determinations, we assess these expenditure proposals to ensure consumers pay no more than necessary for a safe and reliable power supply. The increases are mostly offset by the return of previously over-recovered distribution revenues. Decreases in costs for Queensland residential customers with controlled load reflect lower prices for controlled load tariffs.
- Environmental costs have decreased across all customer types, driven by decreases in the federal renewable energy target schemes.
- Retail costs have increased across all customers by 35.4% for residential customers and 17.5% for small business customers. This has been primarily due to increases in operating costs, smart meter costs and increases in bad and doubtful debt costs.
- Retail margin has increased in DMO 7 primarily due to increases in network and retail costs. The retail margin is set at 6% of the total DMO price for residential customers and 11% for small business, so increases in other components of the cost stack cause the retail margin to also increase.

Table E.4 Summary of DMO price changes from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7, SE Queensland (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Final determination DMO 7		Difference from DMO 6 to Draft DMO 7		Difference from DMO 7 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 6 to draft determination DMO 7 and final determination DMO 7 (nominal)													
Energex	Network cost	767.70		788.19		778.45		20.49	2.7%	-9.74	-1.2%	10.75	1.4%
	Wholesale cost	847.87		861.20		847.01		13.33	1.6%	-14.19	-1.6%	-0.86	-0.1%
	Environmental cost	83.64		62.85		60.31		-20.80	-24.9%	-2.54	-4.0%	-23.34	-27.9%
	Retail cost	242.45		341.25		328.20		98.80	40.7%	-13.05	-3.8%	85.75	35.4%
	Retail margin	123.94	*6.0%*	131.07	*6.0%*	128.55	*6.0%*	7.14	5.8%	-2.52	-1.9%	4.61	3.7%
	Total	**2,066**		**2,185**		**2,143**		**119**	**5.8%**	**-42**	**-1.9%**	**77**	**3.7%**
Residential with CL, change from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7 (nominal)													
Energex	Network cost	870.27		828.09		811.08		-42.18	-4.8%	-17.01	-2.1%	-59.19	-6.8%
	Wholesale cost	1,041.80		1,071.38		1,057.39		29.58	2.8%	-14.00	-1.3%	15.58	1.5%
	Environmental cost	114.55		86.07		82.59		-28.48	-24.9%	-3.48	-4.0%	-31.96	-27.9%
	Retail cost	242.45		341.25		328.20		98.80	40.7%	-13.05	-3.8%	85.75	35.4%
	Retail margin	144.84	*6.0%*	148.52	*6.0%*	145.48	*6.0%*	3.68	2.5%	-3.03	-2.0%	0.65	0.4%
	Total	**2,414**		**2,475**		**2,425**		**61**	**2.5%**	**-50**	**-2.0%**	**11**	**0.5%**
Small business without CL, change from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7 (nominal)													
Energex	Network cost	1,475.39		1,585.14		1,506.37		109.75	7.4%	-78.77	-5.0%	30.98	2.1%
	Wholesale cost	1,827.81		1,856.68		1,823.45		28.87	1.6%	-33.23	-1.8%	-4.36	-0.2%
	Environmental cost	181.83		136.62		131.10		-45.21	-24.9%	-5.52	-4.0%	-50.73	-27.9%
	Retail cost	306.97		372.09		360.66		65.13	21.2%	-11.44	-3.1%	53.69	17.5%
	Retail margin	468.67	*11.0%*	488.27	*11.0%*	472.33	*11.0%*	19.59	4.2%	-15.94	-3.3%	3.66	0.8%
	Total	**4,261**		**4,439**		**4,294**		**178**	**4.2%**	**-145**	**-3.3%**	**33**	**0.8%**

Source: AER Default market offer 2025–26 cost assessment model.

South Australia summary

South Australian **residential customers without controlled load** will experience a price increase of $71 or 3.2% (0.8% above forecast inflation).

Residential **customers with controlled load** face an increase of $64 or 2.3% (0.1% below forecast inflation).

Small business customers will see an increase of $189 or 3.5% (1.1% above forecast inflation).

As outlined in Table E.5, since the DMO 6 final determination we have observed the following in South Australia:

- Wholesale cost increases 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 2025–26 on an annualised and trade-weighted basis were increases in base futures contract prices of $2.40/MWh and in cap contract prices of $2.90/MWh.
  - The load profile used to model wholesale costs in South Australia has become peakier during the evening, resulting in higher hedging costs.
  - Minor changes in other wholesale costs partially offset the increases, primarily from decreases in direction costs from AEMO.
- Network costs have decreased for residential customers with and without controlled load and increased for small business customers. Increases in network costs for small business customers are driven by the price path in our 1 July 2025 to 30 June 2030 regulatory determination for SA Power Networks. The price path increase is largely due to a higher return on capital, which is driven by market factors (higher actual inflation and interest rates). Our determinations also included expenditure in important emerging areas such as improved network resilience to address climate change-related risks, the uptake and integration of consumer energy resources (including rooftop solar, batteries and electrical vehicles), expenditure to improve the management of safety risks to the public and workers and cyber security. In making our revenue determinations, we assess these expenditure proposals to ensure consumers pay no more than necessary for a safe and reliable power supply. This is partially offset by the return of previously over-recovered revenues. Decreases in costs for South Australian residential customers reflect a reduced allocation of transmission costs to the residential flat rate tariff.
- Environmental costs have decreased across all customers, mainly driven by decreases in both federal and state renewable energy target schemes.
- Retail costs have increased across all customers. The year-on-year increase of 8.3% to 23.6% is primarily due to increased operating costs, and increases in bad and doubtful debt and smart meter costs.
- Retail margin has increased in DMO 7 due to increases in wholesale and retail costs. The retail margin is set at 6% of the total DMO price for residential customers and 11% for small business customers, so increases in other components of the cost stack cause the retail margin to also increase.

Table E.5 Summary of DMO price changes from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7, South Australia (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Final determination DMO 7		Difference from DMO 6 to Draft DMO 7		Difference from DMO 7 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 6 to draft determination DMO 7 and final determination DMO 7 (nominal)													
SA Power Networks	Network cost	922.34		900.67		896.99		-21.67	-2.3%	-3.68	-0.4%	-25.35	-2.7%
	Wholesale cost	805.77		890.38		858.80		84.60	10.5%	-31.58	-3.5%	53.02	6.6%
	Environmental cost	97.50		76.30		72.25		-21.21	-21.8%	-4.05	-5.3%	-25.26	-25.9%
	Retail cost	270.61		335.69		334.47		65.09	24.1%	-1.22	-0.4%	63.87	23.6%
	Retail margin	133.80	*6.0%*	140.62	*6.0%*	138.03	*6.0%*	6.82	5.1%	-2.59	-1.8%	4.23	3.2%
	Total	**2,230**		**2,344**		**2,301**		**114**	**5.1%**	**-43**	**-1.8%**	**71**	**3.2%**
Residential with CL, change from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7 (nominal)													
SA Power Networks	Network cost	1,105.12		1,077.33		1,072.66		-27.79	-2.5%	-4.67	-0.4%	-32.46	-2.9%
	Wholesale cost	1,072.05		1,181.06		1,138.96		109.01	10.2%	-42.10	-3.6%	66.91	6.2%
	Environmental cost	146.26		114.44		108.37		-31.81	-21.8%	-6.07	-5.3%	-37.89	-25.9%
	Retail cost	270.61		335.69		334.47		65.09	24.1%	-1.22	-0.4%	63.87	23.6%
	Retail margin	165.58	*6.0%*	172.89	*6.0%*	169.43	*6.0%*	7.31	4.4%	-3.45	-2.0%	3.86	2.3%
	Total	**2,760**		**2,881**		**2,824**		**121**	**4.4%**	**-57**	**-2.0%**	**64**	**2.3%**
Small business without CL, change from final determination DMO 6 to draft determination DMO 7 and final determination DMO 7 (nominal)													
SA Power Networks	Network cost	2,206.45		2,299.44		2,281.98		92.99	4.2%	-17.46	-0.8%	75.53	3.4%
	Wholesale cost	1,994.79		2,206.15		2,124.17		211.36	10.6%	-81.98	-3.7%	129.38	6.5%
	Environmental cost	243.76		190.74		180.62		-53.02	-21.8%	-10.12	-5.3%	-63.14	-25.9%
	Retail cost	318.27		383.02		344.73		64.75	20.3%	-38.29	-10.0%	26.46	8.3%
	Retail margin	588.72	*11.0%*	627.78	*11.0%*	609.51	*11.0%*	39.07	6.6%	-18.27	-2.9%	20.79	3.5%
	Total	**5,352**		**5,707**		**5,541**		**355**	**6.6%**	**-166**	**-2.9%**	**189**	**3.5%**

Source: AER Default market offer 2025–26 cost assessment model.