



Australian Government



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Default market offer 2026–27

Issues paper

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Inquiries about this publication should be addressed to:

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

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Invitation for submissions

Interested parties are invited to make submissions on this issues paper by close of business, Wednesday 26 November 2025.

Submissions should be sent to: DMO@aer.gov.au

Alternatively, submissions can be sent to:

Adam Day
a/g Executive Director, Default Market Offer and Consumers
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

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

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

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

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

Key DMO concepts

The table below summarises key methodological approaches, definitions and considerations made in relation to and used in the DMO 8 issues paper.

Cost-stack component	Aspect	Approach
General	AEMO Market Settlement and Transfer System	A system designed to facilitate customer transfer process and provide data for the efficient settlement in the National Electricity Market.
General	Annual price	For DMOs 1 to 7, the AER has calculated the DMO as annual prices for a given amount of usage and pattern of usage determined by the AER. Retailers must not price their standing offers such that their annual price for the annual usage amount and pattern (if applicable) is greater than the DMO price. This is different to other regulators that determine a standing offer tariff.
General	Distribution network service providers	An entity that owns, operates or controls a distribution network's physical infrastructure, including the poles, cables, substations, transformers and safety equipment.
General	Maximum annual bill	An annual amount calculated to provide price protection to standing offer customers for which there is no corresponding DMO regulated tariff. For example, standing offer customers on a demand tariff would be protected by the maximum annual bill. This is a new requirement for the AER to determine as part of the recommended reforms.
General	Outcomes paper	The paper published by the Australian Government on 4 November 2025 summarising outcomes of the 2025 review of the DMO. The paper includes a package of recommended reforms aimed at strengthening the DMO's role in protecting customers on standing offers and small customers in embedded networks, and improving the DMO's effectiveness as a comparison tool.
General	Tariff	Under the proposed Regulations, from DMO 8 onward, the AER will be required to express the DMO in tariff form. Electricity tariffs include a fixed daily supply charge presented in dollars per day (\$/day) and a variable usage charge presented in cents per kilowatt hour (c/kWh).
Wholesale	Net System Load Profile	Data that contains aggregated electricity consumption of all customers with accumulation meters (or legacy meters) only.

Cost-stack component	Aspect	Approach
Wholesale	Load profile	The aggregate customer consumption (or demand) profile for residential and small business customers, which is a key input into forecasting wholesale energy costs for the DMO. Since DMO 6, the AER has used a blend of Net System Load Profile data (to reflect customers with accumulation meters) and interval meter data (to reflect customers with interval meters).
Wholesale	Percentile estimate	The selected modelled wholesale cost estimate from the distribution of almost 600 modelled wholesale energy costs produced by our wholesale consultant, based on various combinations of weather, baseload availability, renewable generation and demand.
Retail	AER information notice / request	An information notice served by the AER for information relating to section 16(4) of the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019, and based on a reason to believe formed by the AER under section 44AAFA(1) of the <i>Competition and Consumer Act 2010</i> .
Retail	Bad debt	Unpaid energy bills that become unrecoverable financial losses for energy retailers. Bad debt can fall into 2 categories: • actual bad debt written off by retailers • provisioned bad and doubtful debt, which is the estimated amount set aside to cover costs for accounts retailers do not expect to be able to collect from.
Retail	Competition allowance	Previous DMOs have either explicitly or implicitly included allowances to incentivise competition through varying approaches across DMOs. In the 2 most recent DMO determinations (DMO 6 and DMO 7), this involved calculating a competition allowance separately to a retail margin and costs to serve. The competition allowance was calculated to allow retailers with higher-than-average costs to serve, e.g. smaller and new entrant retailers, to make a reasonable profit when selling at the DMO price. We also introduced an element into our DMO methodology during DMO 6 and 7 whereby we would not apply the competition allowance if the consumer price index was outside the Reserve Bank of Australia's target band on a material and sustained basis. The competition allowance was not included in the DMO 6 or 7 prices as a result of this consideration of cost-of-living pressures.

Cost-stack component	Aspect	Approach
Retail	Costs to Acquire and Retain	Costs relating to competition in the electricity market. The group of costs electricity retailers incur to acquire new customers and retain current customers. Costs include advertising, marketing, etc.
Retail	Costs to Serve	The group of costs electricity retailers incur as part of serving its customers, such as billing and call centres.
Retail	Market offer	Market offers are offers retailers make to customers under a market retail contract. The National Energy Retail Rules do not prescribe terms and conditions for market offer plans but contain minimum requirements for these contracts. As such, market offer contracts may be different to standard retail contracts. For example, retailers may be able to change prices more frequently under a market offer plan but may offer lower tariffs or other beneficial terms and conditions that appeal to customers.
Retail	Retail cost data	The data received from the information request above.
Retail	Retail margin	Included in the DMO price. A return to retailers reflecting the risk of selling electricity. For DMO 7 this was 6% and 11% of the DMO residential and small business prices, respectively.
Retail	Smart meter	Also referred to as interval meter, a meter with the ability to record consumption in 30-minute intervals, allowing time-of-use and other flexible tariffs. Smart meters are managed by retailers.
Retail	Standing offer	It is a default electricity plan intended to provide a level of protection to customers not engaged in the retail electricity market. This may be due to various reasons, such as if they have never switched to a retailer's market offer or may have defaulted to a standing offer at the end of their market offer benefit period.
Environmental	Large-scale Renewable Energy Target	The Large-scale Renewable Energy Target encourages investment in the development of renewable energy power stations, like wind and solar farms, by providing a financial incentive for electricity generated from renewable sources.
Environmental	Small-scale Renewable Energy Scheme	The Small-scale Renewable Energy Scheme 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 source pumps.

Cost-stack component	Aspect	Approach
Usage	Annual usage	An annual electricity consumption amount considered broadly representative by the AER. This amount is applied to retailer’s individual standing and market offers to determine whether standing offers are compliant with the DMO annual price.
Usage	Pattern of supply	Different levels of electricity used by residential customers and small business throughout the day. The varying levels of demand form the pattern of supply.

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CER	Clean Energy Regulator
CPI	Consumer price index
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DMO	Default market offer
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
DMO 9	Default market offer determination for 2027–28
DNSP	Distribution network service provider
ESC	Essential Services Commission
ICRC	Independent Competition and Regulatory Commission
NEM	National Electricity Market
NSLP	Net System Load Profile
NSW	New South Wales
OTTER	Office of the Tasmanian Economic Regulator
QCA	Queensland Competition Authority
SA	South Australia
VDO	Victorian Default Offer
WEC	Wholesale energy cost

1 Introduction

This marks the release of the Australian Energy Regulator's (AER) eighth issues paper for the electricity retail default market offer (DMO). This issues paper is the first step in our development of DMO 8 to set out the DMO prices that will apply from 1 July 2026 to 30 June 2027.

1.1 Default market offer

The DMO is the maximum price an electricity retailer can charge standing offer customers.¹ Standing offers are default electricity plans intended to provide a level of protection to customers who do not or cannot engage in the electricity retail market.²

Since its inception, the DMO has acted as an electricity price 'safety net', protecting consumers from unjustifiably high prices while also allowing retailers to recover costs. The DMO price for each area also acts as a reference price, helping consumers compare different residential and small business electricity offers.³

The AER's role is to determine the DMO price annually. Our DMO price determination applies to residential and small business customers across South Australia, New South Wales (NSW) and South East Queensland, where there is no other retail price regulation.

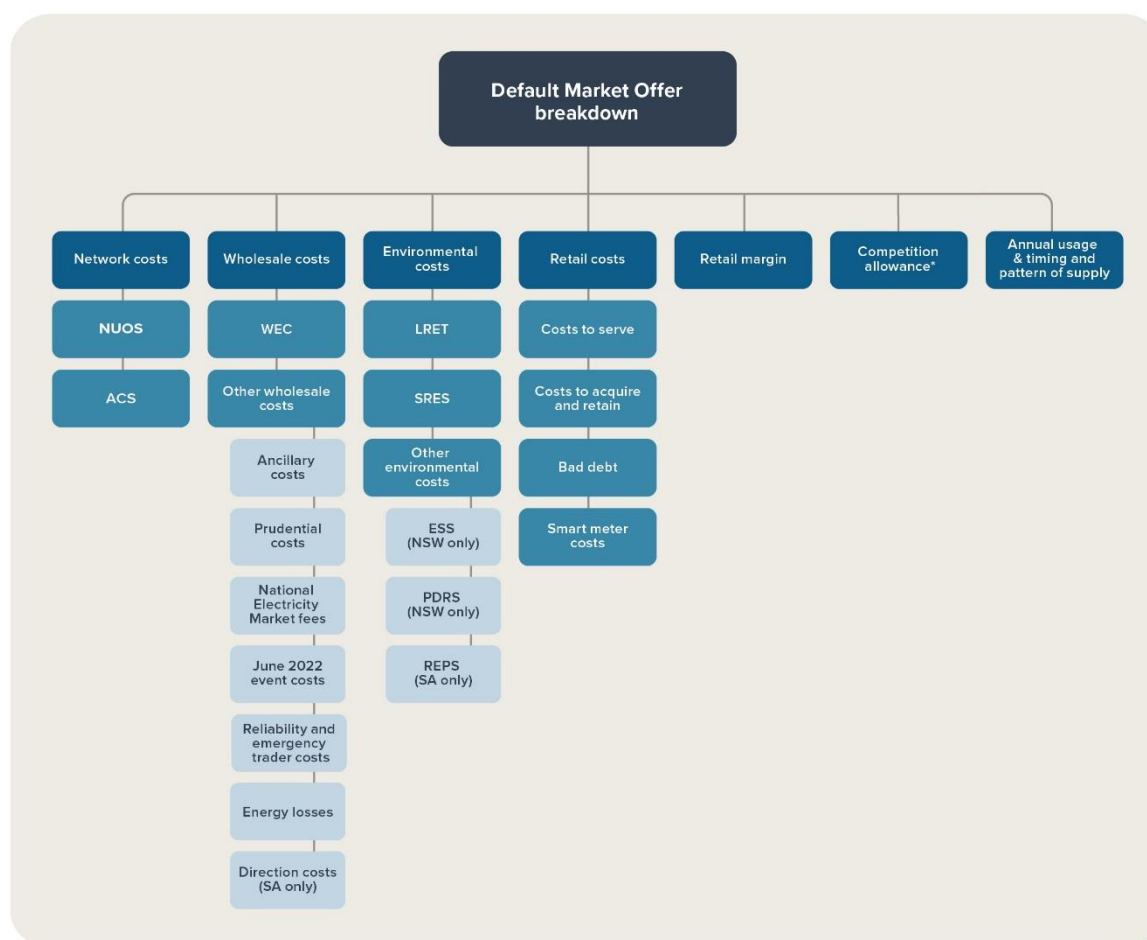
The Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (the Regulations) set out the legislative framework for the DMO. Throughout each DMO process, we consider network, wholesale, environmental and retail operating costs as well as the retail margin and any allowances to determine a reasonable price (Figure 1.1).

For the past 7 DMOs, the AER has applied the Regulations and had regard to guiding policy objectives set by government when determining the annual DMO price. The DMO framework has recently been reviewed by the Australian Government Department of Climate Change, Energy, the Environment and Water (DCCEEW). This review focused on potential reforms to the DMO regulatory framework that would ensure it is fit-for-purpose to address the current and emerging challenges in the retail electricity space.

¹ Standing offers have been defined in the Key DMO concepts table.

² The cap on standing offer prices does not apply to customers on demand tariffs or small business customers on flexible or time-of-use tariffs.

³ When advertising or promoting an offer, retailers must show the price of the offer in comparison to the DMO.

Figure 1.1 DMO cost structure

Note: The competition allowance has been marked with an asterisk because it is proposed to not apply in DMO 8. Acronyms are defined as follows: NUOS – Network Use of System charges, ACS – Alternative Control Services charges, WEC – Wholesale energy cost, LRET – Large-scale Renewable Energy Target costs, SRES – Small-scale Renewable Energy Scheme costs, ESS – Energy Savings Scheme, PDRS – Peak Demand Reduction Scheme, REPS – Retailer Energy Productivity Scheme.

1.2 Approach for consultation

The AER's DMO issues paper typically sets out our approach for each year's determination of the DMO and seeks stakeholder comment on various aspects of the DMO methodology that may need to be refined or changed. Given the outcomes of the DMO framework review, we have developed this issues paper based on the Australian Government's intention for the reforms to take effect for DMO 8.⁴

The Regulations will need to be amended before the AER can apply such new measures for the DMO 8 draft determination. If there is a delay to this and the recommended changes to the Regulations are not adopted, the AER will need to publish the DMO 8 draft determination in accordance with the current Regulations.

⁴ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Chapter 1: Scope of Reforms.

This issues paper also seeks input from stakeholders on the changes that we would make under either the current Regulations or the proposed reforms. A number of these refinements for DMO 8 were foreshadowed in the DMO 7 final determination. To make it clear for stakeholders, we explicitly set out when a topic applies to the current Regulations. We also specifically note when a consultation question is exclusively related to the current Regulations and would not apply under the proposed reforms.

This issues paper represents our best point-in-time attempt to identify all the potential methodological changes to consult on under the recommended changes to the Regulations in the final outcomes paper. However, the final form of the enacted Regulations may present additional methodological considerations beyond those envisaged in this issues paper. If this occurs, stakeholders will still have an opportunity to provide feedback to these additional considerations in submissions to our draft determination, which will be published after the Regulations are in effect.

1.3 Next steps

Our timetable for the development of DMO 8 is as follows:

Date	Milestone
5 November 2025	AER DMO 8 issues paper consultation commences
Mid-November 2025	AER DMO 8 issues paper stakeholder engagement
26 November 2025	AER DMO 8 issues paper submissions due
Prior to draft determination	Regulations amended to bring new DMO framework into effect
March 2026	AER DMO 8 draft determination published for consultation
April 2026	AER DMO 8 draft determination submissions due
26 May 2026	AER DMO 8 final determination published
1 July 2026	DMO 8 in force

2 2025 reforms to the DMO

This chapter summarises the Australian Government's recommended reforms to the Regulations and how this will change the AER's DMO process.

On 4 November 2025, DCCEEW announced the outcomes of the DMO framework review, including a package of recommendations that seek to:

1. introduce a new guiding DMO objective focussed on protecting small customers on standing offers and small customers in embedded networks
2. require the determination of the DMO based on the efficient costs of supplying those customers and cap the prices payable by those customers
3. require the AER to determine a tariff cap for common standing offer tariff types to improve consumer price protections.⁵

We have summarised the outcomes of the review below. Chapter 3 elaborates on some of these impacts and seeks stakeholder views to shape the AER's approach to implementing the proposed recommendations for DMO 8.

2.1 Current and proposed DMO policy objectives and mandatory considerations

Current objectives and considerations

Since the Regulations were introduced, the AER has made DMO determinations in accordance with the Regulations by determining a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of a type in a region.⁶ To determine a reasonable annual price, the Regulations have required us to have regard to a range of specific matters and costs:⁷

- 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)

⁵ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Overview of recommendations.

⁶ Regulations, s. 16(1)(b).

⁷ Regulations, s. 16(4).

- the cost of serving small customers.

We have also had the ability to have regard to any other matter the AER considers relevant.⁸

The AER’s approach has also been guided by policy objectives and advice from various sources, including recommendations from the Australian Competition and Consumer Commission (ACCC) in the Retail Electricity Pricing Inquiry and letters from the Australian and state governments.^{9 10} This advice from the Australian and state governments and the following policy objectives are the matters we have considered relevant when setting a reasonable price.

Figure 2.1 Original DMO policy objectives



Proposed objective and mandatory considerations

The DCCEEW outcomes paper proposes to introduce a single objective into the Regulations and additional mandatory considerations for the AER when determining the DMO (Figure 2.2). The DMO objective would be to ‘protect households and small businesses on standing offers and in embedded networks by providing a fair, trusted and reasonably priced electricity option that reflects the costs of supplying customers with an essential service’.¹¹ Further, the outcomes paper states that the AER would not be permitted to include a competition

⁸ Regulations, s. 16(4)(d).

⁹ 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 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.

¹⁰ 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.

¹¹ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 1.

allowance in the DMO.¹² It is also recommended that the current principle that an electricity retailer should be able to make a reasonable profit be removed.¹³

Figure 2.2 New single objective and mandatory considerations



The recommended mandatory considerations require the AER to consider efficient costs to supply small customers on standing offers, including modest costs for customer acquisition and retention. These are not an exhaustive list of matters for consideration, but when making the DMO 8 determination the AER will apply them along with any other matters specified in the Regulations. This issues paper discusses how the AER will approach these new mandatory considerations and invites stakeholder feedback.

2.2 Who the DMO protects

The outcomes paper notes that, under the proposed amendments to the Regulations, the DMO will be reformed in a staged way to protect all customers on standing offers and all small customers in embedded networks. The AER will be required to set DMO tariffs for tariff types specified in the amended Regulations and will have discretion to set a DMO regulated tariff for other standing offer or embedded network tariff types.

All standing offer customers and small customers in embedded networks would be protected under the proposed amendments. The form of protection provided would depend on the customer and tariff type, as discussed below.

Tariffs the AER must determine

For DMOs 1 to 7, the AER was required to set DMO prices for the following types of small customers as set in the Regulations:¹⁴

- residential customers on flat rate or time-of-use tariffs

¹² DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 2.

¹³ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Section 3.2: Considerations.

¹⁴ Regulations, s. 6.

- residential customers with controlled load – controlled load tariffs are separately metered tariffs used for appliances such as electric hot water storage systems, pool pumps or underfloor heating
- small business customers (without controlled load) on flat rate tariffs.

Under the proposed reforms, the AER will continue to be required to determine a cap for these customer types. In addition, for DMO 8, we will be required to determine a cap for small business customers (without controlled load) on a simple time-of-use tariff.

From DMO 9 onwards, the AER will also be required to set the DMO for small customers supplied by authorised retailers in embedded networks.¹⁵

As discussed in section 2.4, the proposed reforms will require these caps to be expressed as a tariff, rather than an annual price cap at a set usage amount, as determined previously.

Tariffs the AER may determine

From DMO 9 onwards, the AER will have discretion to determine tariff caps for other standing offer or embedded network tariff types.¹⁶

The AER will consult on whether the DMO should regulate additional types of tariff caps as part of the DMO guideline development (discussed in section 2.6).

Protection for non-standard standing offer customers – maximum annual bill

If the AER has not set a DMO tariff for a particular tariff structure, standing offer customers on that tariff would still be protected by the DMO framework through a maximum annual bill, with the amount to be set by the AER.¹⁷ This ensures that, for example, customers on a standing offer tariff with a demand charge component, or small business customers on a standing offer tariff with a controlled load component, would still be protected. The annual price (for a given annual usage amount and pattern of supply) of these non-standard standing offers must not exceed the maximum annual bill amount determined by the AER. Section 3.2 discusses our proposed approach to determining maximum annual bill amounts.

Embedded network customers

From DMO 9 onwards, it is proposed that the DMO be expanded to protect customers in embedded networks (both residential and small business) served by an authorised retailer. Currently, only customers in embedded networks served by an exempt seller are protected by the DMO. Energy charges for these embedded network customers must be no higher than the standing offer prices that a local area retailer can charge contracted customers. These customers would continue to be protected under the proposed reforms.

¹⁵ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 4 and Transitional arrangements.

¹⁶ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 6.

¹⁷ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 7.

Market offer prices for small customers in all embedded networks, regardless of whether they are supplied by an exempt seller or authorised retailer, would be capped based on the respective DMO tariff caps determined by the AER. Small customers in embedded networks not covered by a DMO tariff cap would be protected by the relevant maximum annual bill set by the AER. The AER would also have the discretion to create DMO tariff types specific to embedded network customers.

In keeping with the recommendations for the DMO guideline as discussed in section 2.6, we will develop our approach to setting DMO tariffs unique to small customers in embedded networks in consultation with stakeholders for DMO 9.

2.3 Efficient costs to supply electricity

The AER will be required to take into account the efficient costs to supply small customers on standing offers and in embedded networks when determining DMO tariffs.¹⁸ To date, the Regulations have required the AER to determine a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of a type in a region.¹⁹ The AER has also been required to have regard to the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region.²⁰

Setting the DMO based on the efficient costs to supply customers will have implications for each element of the DMO cost stack, which are discussed in relevant individual chapters of this paper.

2.4 Tariff cap

The DCCEEW outcomes paper notes the AER will be required to determine a tariff cap for specified small customer types instead of an annual price at a set usage amount.²¹ This change in expression would bring the DMO into closer alignment with other regulated pricing frameworks, including the Essential Services Commission’s (ESC) Victorian Default Offer (VDO) and Queensland Competition Authority’s (QCA) regulated electricity prices in regional Queensland. A tariff cap expression will affect how the DMO apportions costs across fixed and variable components of the tariff, which is discussed further in section 3.1. This change will also affect how we assign network tariffs, which is discussed further in chapter 4.

The AER would still calculate annual prices for the purposes of determining the maximum annual bill (see section 2.2), the comparison price role (see section 2.5) and allowing ease of comparison with previous DMO determinations.

¹⁸ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 2.

¹⁹ Regulations, s. 16(1)(b).

²⁰ Regulations, s. 16(4)(b).

²¹ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 5.

2.5 Comparison price role

The outcomes paper recommends changing the language used in the DMO; specifically, to use the term ‘comparison price set by the Australian Energy Regulator’ instead of ‘reference price’.²² It also recommends extending the DMO’s comparison price role to all market offers.²³ Under the current Regulations, market offers with a different structure to standing offers covered by the DMO do not have any pricing communication requirements.

For any market offer that has the same or similar tariff structure to a DMO tariff, a retailer must compare the price of its market offer to the corresponding DMO tariff when advertising and engaging with customers.

For any other market offer type, a retailer must convert the market offer into an annual price using annual usage assumptions determined by the AER and then compare it against the maximum annual bill (discussed in section 3.2).

The ACCC monitors and enforces the Regulations as a mandatory industry code prescribed under the *Competition and Consumer Act 2010*. The ACCC will still be responsible for retailers’ compliance with the Regulations when the reforms are in force.

2.6 New DMO guideline

Under the proposed reforms, the AER will be required to develop a guideline on our approach to determining the DMO. This document must be published in 2026 before commencing the process to determine DMO 9. It must also be developed in consultation and can be amended from time to time.²⁴ The aim of the DMO guideline is to enhance transparency and regulatory certainty by setting out our intended approach to:

- identify the cost components we propose to include in the DMO
- determine the cost components of the DMO, including the information and data we intend to use
- consider the additional standing offer types that should be specified as a DMO tariff
- determine the DMO for embedded network customers
- undertake the DMO determination process each year.

The outcomes paper notes that the guideline would not bind the AER in making a DMO determination. DCCEEW recommended the AER be required to provide reasons for departing from the DMO guideline in any DMO determination. The guideline will be an

²² DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Section 3.6.

²³ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 9.

²⁴ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 3.

enduring complement to the current approach to annually review the DMO through the issues paper consultation, which will only consult on a more specific set of issues.²⁵

We intend to develop and consult on this guideline between the DMO 8 final determination and DMO 9 issues paper.

2.7 Solar Sharer Offer

The outcomes paper recommends introducing a new time-of-use tariff category under the DMO framework called a Solar Sharer Offer (SSO).²⁶ The SSO would provide all consumers on that offer zero-cost electricity during designated time windows. The Australian Government has commenced consultation on the application and implementation of the SSO.

Under this new requirement, all electricity retailers must offer a SSO standing offer tariff under the DMO or an approved alternative. The implementation would be phased, commencing with DMO jurisdictions by 1 July 2026 to align with DMO 8, with further consultation to occur in preparation of a potential national rollout from 2027.

Given the imminent rollout of SSO tariffs to DMO jurisdictions for DMO 8, we propose to consider the outcomes of DCCEE's SSO tariff consultation. Input stakeholders provide as part of that consultation may inform how we calculate the SSO for DMO 8. Therefore, we encourage stakeholders to engage in the DCCEE process. If required, we will conduct targeted consultation (such as industry and consumer group workshops) on our approach to setting SSO tariffs prior to finalising the DMO 8 draft determination.

²⁵ DCCEE, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Section 3.2: Considerations.

²⁶ DCCEE, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 10.

3 Overall changes to the DMO

This chapter discusses the overarching impacts of the outcomes of the DMO framework review on the AER's approach to setting DMO prices for DMO 8. This includes our approach to allocating fixed and variable costs across elements of the DMO tariffs and determining maximum annual bills.

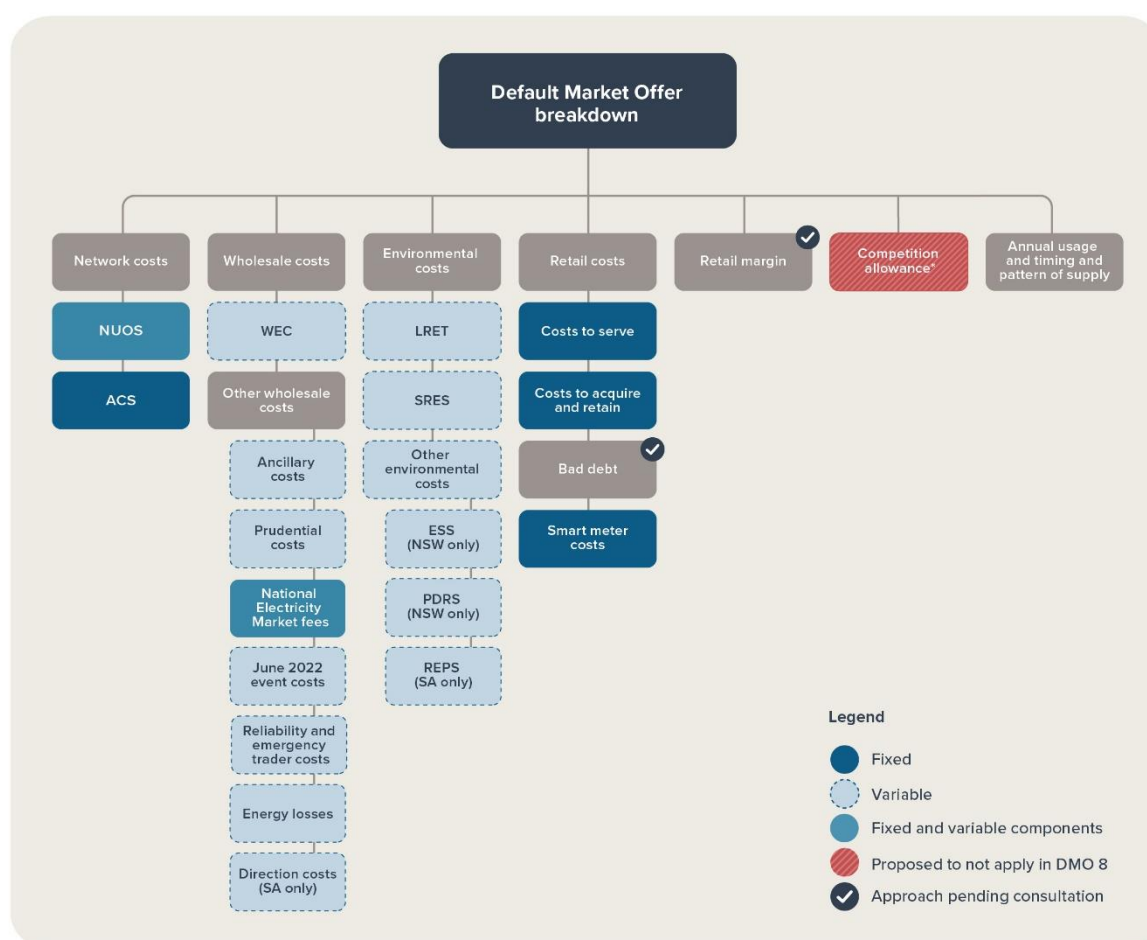
3.1 Allocation of fixed and variable costs

Simple electricity tariffs include a fixed daily supply charge presented in dollars per day (\$/day) and a variable usage charge presented in cents per kilowatt hour (c/kWh). A key implication of a tariff structure for the DMO will be the allocation of cost components across these elements of the tariff. To date, the DMO has been expressed as an annual price for a set usage amount and we have built up a cost stack on this basis. However, with the proposed tariff expression for the DMO, we consider it appropriate to instead build separate fixed and variable cost stacks to create DMO tariffs. This is the approach of the ESC and QCA, and allows for the accurate and equitable recovery of fixed and variable costs across all ranges of customer usage amounts.

We consider all costs should be categorised as either fixed or variable components, or a combination of both where we consider a cost has both fixed and variable elements (Figure 3.1). This would mostly be done in alignment with previous DMO determination cost assessment models where we have already allocated cost components as either variable or fixed in the calculation of annual DMO prices. We consider retailers' costs of supplying electricity are driven in two ways:

- Number of customers served – these are 'fixed costs' that increase as the number of customers served by a retailer increase. Examples include call centres, billing and advertising costs.
- Volume of energy sold – these are 'variable costs' that increase as the volume of electricity sold increases. Examples include wholesale energy costs and environmental scheme costs.

We propose that variable costs (that were previously multiplied by annual usage amounts) be allocated to the usage charge of the tariff, and any other costs be allocated to the daily supply charge. For example, wholesale costs would remain almost entirely variable except for the fixed element of National Electricity Market fees. However, there are also some elements that require further consideration, including network tariffs, bad debt and retail margins. Discussion of these cost components and how they could be captured in the tariff cap are detailed in sections 4.1.2, 7.4 and 8.1.2.

Figure 3.1 Proposed apportionment of DMO cost components

Note: The competition allowance has been marked with an asterisk because it is proposed to not apply in DMO 8. Acronyms are defined as follows: NUOS – Network Use of System charges, ACS – Alternative Control Services charges, WEC – Wholesale energy cost, LRET – Large-scale Renewable Energy Target costs, SRES – Small-scale Renewable Energy Scheme costs, ESS – Energy Savings Scheme, PDRS – Peak Demand Reduction Scheme, REPS – Retailer Energy Productivity Scheme.

Question 1: How should the AER apportion costs across the supply and usage charge elements of the tariff? Is the proposed apportionment of cost elements appropriate?

3.2 Approach to determining maximum annual bills

The AER will be required to determine a maximum annual bill amount for types of customers on standing offers for which there is no DMO regulated tariff. As explained in section 2.2, these amounts will be used to provide price protection to non-standard standing offer customers.

We propose to determine maximum annual bill amounts by annualising the cost of the flat rate DMO tariff using given annual usage amounts determined by the AER for residential and small business customers, respectively. This is similar to previous DMOs that were expressed as an annual price. We consider this to be the simplest and most transparent

approach that is least impacted by any assumptions made by the AER on usage patterns and timing. Further, annualising the flat tariff would ensure that small customers on standing offers with more sophisticated cost-reflective tariff structures not covered by the DMO would not pay more than standing offer customers on a flat tariff (at a given usage amount).

We note the approach to annualise the flat tariff aligns with the approach the ESC is required to follow to determine the VDO ‘compliant maximum annual bill’ that protects customers on non-standard standing offers in Victoria.

Question 2: How should the AER determine maximum annual bill amounts? Should they be based on the flat DMO tariffs?

4 Network costs

In a retail electricity bill, network costs represent the cost a network distributor incurs in transporting electricity to a customer, as well costs to safely manage these networks and measure this electricity.

Under the National Electricity Rules, the AER regulates network charges by approving the network tariffs that distribution network businesses set on an annual basis.²⁷ Network charges typically comprise:

- Distribution Use of System (DUoS) charges – the recovery of regulated distribution revenues, reflecting the costs of delivering safe and reliable electricity to customers and for managing the distribution network
- Transmission Use of System (TUoS) charges – the recovery of regulated transmission revenues, reflecting the costs of delivering safe and reliable energy to distribution networks and for managing the transmission network
- metering charges – covers the maintenance, reading, data services and the recovery of capital costs for accumulations and interval meters
- jurisdictional schemes – the recovery of costs to support jurisdictional schemes, including (but not limited to) premium feed-in tariffs and renewable energy zones.

4.1 Blending network tariffs

In DMO 7, as with prior DMOs, network costs were based on the approved flat rate network tariff prices. However, there continues to be a growing proportion of customers being assigned to time-of-use or other flexible network tariffs. Stakeholder submissions on the DMO 7 draft determination were largely supportive of a blended estimate or alternative approaches being explored for DMO 8 and future determinations to develop a more accurate approach. They noted the increased installation of smart meters and reassignment of customers onto time-of-use and other network tariffs will make a flat rate approach less reflective of costs that retailers actually incur.²⁸

Under the AEMC accelerating smart meter deployment rule change, retailers will require explicit informed consent to assign customers onto corresponding flexible retail tariffs for 2 years from the point of installation.²⁹ It is possible that a proportion of these customers will remain on flat rate retail offers, resulting in a mismatch between network and retail tariffs. This aspect of retailer pricing will persist regardless of whether the Regulations change.

The outcomes paper considers this potential misalignment between the network tariff structure and the DMO tariff. DCCEEW recognises this misalignment represents a risk for

²⁷ National Electricity Rules 2025, clause 6.18.2.

²⁸ 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.

²⁹ AEMC, [National Electricity Amendment \(Accelerating Smart Meter Deployment\) Rule](#), Australian Energy Market Commission, 28 November 2024, p. 28.

retailers but considers it may be appropriate to use the most common network tariffs in the relevant distribution regions. However, DCCEEW also recommends giving the AER discretion to decide the appropriate approach for determining network costs in DMO tariffs.

The proposed Regulations direct the AER to determine separate flat rate and time-of-use retail tariffs (and other retail tariffs if applicable). Therefore, it may be more appropriate to assign the respective network tariff to the corresponding DMO retail tariff (for example, for time-of-use retail tariffs, a time-of-use network tariff would be used), instead of developing a blended network tariff. This approach would be simpler and more transparent than developing a blended network cost that then requires reapportioning across the different flat rate and time-of-use DMO tariffs. We note that the other regulators that determine retail tariffs assign network tariffs corresponding to retail tariffs.³⁰

However, the proposed Regulations also require the AER to determine a maximum annual bill, which acts as a price cap for standing offers, and a reference price for market offers, that are of a different tariff structure to a DMO tariff. While the exact details of the maximum annual bill are still to be determined, it may be appropriate for this ‘catch all’ price to include a blended network cost (noting the issues discussed in section 4.1.1), rather than a particular network tariff.

If the Regulations do not change, we will be required to determine a single DMO price for each customer type. In this context, it may be appropriate to move to a blended network approach instead of continuing the approach since DMO 2 of adopting the flat rate network tariff. While a blended network approach is more complex (as discussed in section 4.1.1), it may result in a more accurate derivation of network costs given that a growing number of customers are on cost-reflective network tariffs.

This issues paper seeks stakeholder feedback on whether we should blend network tariffs to determine network costs under both the proposed reforms and the current Regulations.

Question 3: Under the proposed Regulations, should the separate flat rate and time-of-use DMO tariffs use the corresponding network tariff to determine network costs? Why or why not? What alternative approaches should be considered?

Question 4: Should the AER develop a blended network cost for the maximum annual bill, or should it instead adopt a particular network tariff? Why or why not? What alternative approaches should be considered?

Question 5: Under the current Regulations, should the AER continue to use the flat rate network tariff or instead develop a blended network tariff to derive network costs?

³⁰ ESC and QCA adopt this approach in setting retail tariffs. OTTER calculates the total revenue Aurora requires to recover its costs by adding all network charges across all network tariffs in TasNetworks, rather than assigning particular network tariff. However, Aurora then designs its retail tariffs which are then assessed by OTTER. The ACT Independent Competition and Regulatory Commission (ICRC) does not set individual retail tariffs and instead determines a price control formula, which restricts the average increase in ActewAGL’s standing offer prices.

4.1.1 Approach to determining blended network tariffs

Under a blended network tariff approach (including for use in determining a maximum annual bill), we would need to estimate annual network costs for each distribution network service provider (DNSP) under the applicable flat rate, time-of-use and any other applicable network tariffs. We would then blend these separate annual costs likely based on a customer-weighted average corresponding to the customer numbers on each network tariff. While this should be possible, further work will be required to determine that the data required to implement a blended network tariff approach is available and suitably robust.

In determining the annual cost, we would need to consider the amount of energy consumed in each distribution business's charging windows ('peak', 'off-peak' and 'shoulder' periods) for an average 'typical' customer. We would draw on the published pricing models provided within distributors' pricing proposals to model this. These models include inputs, calculations and outputs related to energy consumption, charging periods and average customers on each tariff.

For small business customers, blending network tariffs is potentially as straightforward as for residential customers under the proposed reforms, as the small business DMO would now apply to all small business customers instead of the subset of small business customers on flat rate tariffs. This would mean that the network pricing information provided by DNSPs should provide sufficient granularity to determine suitable weightings for blending small business network tariffs.

However, if the Regulations do not change, the DMO will continue to apply to residential customers on a flat rate tariff or time-of-use tariff and only small business customers on a flat rate tariff. For small business customers, to calculate a blended network tariff cost we would need to know the separate proportions of flat-rate small business customers with flat rate network tariffs and time-of-use network tariffs. Retailers will report on this information under the new retail performance reporting guidelines that come into effect for Q1 2025–26. This information may be suitable in developing blended network costs, but this would need to be tested once the information is received.

Question 6: If we were to create a blended cost, how could the issues for small business network tariffs be overcome?

4.1.2 Selecting the appropriate network tariff to apply to the DMO tariff

If we do not blend flat rate, time-of-use and other network tariffs to derive a single network cost, there is still a complexity in selecting a particular network tariff to form the basis for calculating network costs for the corresponding DMO tariff – in some instances, there are more than one default network tariff of the same structure as the retail tariff. This occurs in the Essential Energy and SA Power Networks regions, which have multiple time-of-use network tariffs (Table 4.1). In these instances, we are seeking stakeholder views on whether to:

- adopt the most common time-of-use network tariff
- apply some blend, such as a weighted average of the multiple time-of-use network tariffs.

Table 4.1 Proportions of customers on time-of-use network tariffs

DNSP	Customer type	Tariff code	Proportion among TOU network tariffs
Essential Energy	Residential	BLNT3AL - TOU 1	65.6%
		BLNRSS2 - TOU 2	31.4%
		BLNT3AU - TOU 3	3.0%
	Small business	BLNT2AL - TOU 1	58.4%
		BLNBSS1 - TOU 2	30.0%
		BLNT2AU - TOU 3	11.6%
SA Power Networks	Small business	SBTOU - TOU 1	78.2%
		B2R - TOU 2	21.8%

Note: DNSP: distribution network service provider. SA Power Networks. TOU: time-of-use.

Source: AER analysis of network pricing proposals

Adopting the most common network tariff of the same structure would be the simpler approach. However, using the most common network tariff might not accurately reflect the overall network costs for a group of customers on that tariff structure, because customers on other network tariffs of the same structure would not be accounted for. The latter approach, applying a blend, may on average more accurately reflect underlying network costs across a tariff structure, but it would introduce methodological complexity in calculating these costs and would not directly match each individual customer's underlying network costs.

Question 7: Where the corresponding network tariffs are used, and there is more than one default network tariff (for instance in Essential Energy and SA Power Networks), what approach should be used?

5 Wholesale costs

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 from the National Electricity Market (NEM).

This is reflected in our ‘market-based’ wholesale methodology, which involves:

- forecasting demand (also known as load) and electricity spot market outcomes
- building an assumed hedging strategy to protect the retailer and its customers during spot market simulations and the extreme price volatility that can occur in the wholesale spot market.

We use an external consultant to assist us with determining wholesale costs in the DMO.

This chapter outlines the aspects of the wholesale cost methodology that we are proposing to refine in DMO 8. Outside of those aspects, we expect to maintain our approach to the wholesale cost methodology unless compelling reasoning or significant market developments warrant a change.

After the finalisation of DMO 7, we assessed the performance of the wholesale model in response to stakeholder feedback from previous DMO determinations. The results are detailed in a standalone report published alongside this issues paper and discussed in section 5.3. Based on findings that the model has generally provided sufficient cost recovery for retailers, we do not intend to consult on detailed modelling inputs such as varying fuel prices and outage rates.

To validate the wholesale cost methodology, we will continue to assess contract data from South Australian market participants, which aims to confirm over-the-counter (OTC) contracts comparable to Australian Securities Exchange (ASX) contracts are broadly aligned in terms of volume and price in the South Australian market. As part of a commitment to ensure our approach to data collection is proportionate and efficient, the AER has committed to ceasing separate collection of OTC data for the purposes of the DMO.³¹ The AER is currently considering outcomes of its consultation on a draft Market Monitoring Information Order (MMIO-ELEC-2025-02).³² The information order seeks to collect contract information, including on standard OTC contracts from several classes, including retailers. We consider that this information (while collected for the purpose of AER’s wholesale market monitoring functions) could be used to compare OTC and ASX contracts as part of the DMO process, once the Order is made. Pending consultation feedback and final decision, we anticipate that the initial submission of information will be due in March 2026 and could be assessed in time for the DMO 8 final determination. This consolidation of contract market information collection will reduce duplication of reporting and regulatory burden for market participants.

³¹ AER, [Letter to the Treasurer and Minister for Finance](#), Australian Energy Regulator, 1 August 2025, p. 3.

³² See our website [for more information on the Market Monitoring Information Order](#) (MMIO-ELEC-2025-02).

5.1 Risk management costs arising from solar exports

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. We therefore exclude solar exports from the interval meter data used to create the blended load profiles for wholesale modelling.

In the DMO 7 draft determination we explored including a solar hedging adjustment to reflect the impact of customers' solar exports on retailers' risk management costs. However, we did not apply this adjustment in our final determination because retailers did not consider it representative of the costs they face in practice, and consumer groups did not support the inclusion of any adjustment.

The DMO 7 final determination indicated we would engage further with retailers to explore alternative ways any potential risk management costs (or benefits) arising from solar exports could be considered within the wholesale methodology. We noted we were also conscious of the need to avoid over-recovery of costs from consumers.

The AER has subsequently engaged with a range of retailers on alternative methods to recognise potential risk management costs arising from solar exports. While the AER cannot disclose confidential information and data provided, retailers reiterated that the presence of solar exports can contribute to their costs. However, this consultation did not result in any new or alternative methodologies to potentially account for risk management costs arising from solar exports.

We consider there are various ways retailers can manage potential risks (and potentially benefit) from customers' solar exports. These include adjustments to feed-in tariffs, the wholesale value of solar exports when a retailer is a net exporter (which can be positive and negative), load flattening measures such as virtual power plant offerings, hot water and electric vehicle charging orchestration and industrial customer load. We maintain that it is not reasonable or possible to reflect all potential hedging strategies that may be employed by retailers across the market and the resulting costs/benefits arising from the presence of customers' solar exports.

We are concerned that introducing an additional element to the DMO in this context could lead to the over-recovery of costs from customers because it would be accounting for a cost that retailers can offset or manage in a range of other ways. Therefore, we do not propose to separately account for any potential risk management costs arising from solar exports in DMO 8.

We also acknowledge retailer views on the cost exposure when a retailer is a net exporter during negative price intervals. However, we note retailers can benefit during positive price intervals and maintain the view that feed-in tariffs continue to be one potential mechanism to mitigate any cost exposure. Under the current Regulations, the AER has been required to disregard feed-in tariffs retailers must pay.³³ While the outcomes paper proposes to remove

³³ Regulations, s. 8A.

this clause from the Regulations, DCCEEW also considers it remains appropriate that costs of feed-in tariffs paid by retailers are not included in the DMO.³⁴

We consider this aligns with our positions set out in previous DMO determinations – that feed-in tariffs are a mechanism retailers can use to manage any potential costs, and reflect benefits, relating to solar exports. The proposed Regulations also require the AER to consider the types of customers on standing offers, who we consider may be less likely to have a solar system installed.

5.2 Controlled load methodology

As discussed above, a key part of the DMO wholesale methodology is to forecast demand (also known as load) to create a load profile. We need to undertake load forecasting for general energy usage as well as a customer's controlled load. Unlike general use energy, controlled load energy is delivered to large appliances (or loads), such as hot water systems, pool pumps and underfloor heating, which are pre-programmed to switch on during times of low demand.

For all prior DMO determinations, the assumed load profile for controlled load has been based on the Controlled Load Profile produced by the Australian Energy Market Operator (AEMO), which used data from a sample of 200 accumulation meters. This profile was used to settle accumulation meter controlled load against spot market outcomes. However, AEMO discontinued production and publication of its Controlled Load Profile in NSW regions in September 2024 and in South Australia on 1 July 2025.³⁵ In both instances, AEMO was advised by the Energy Ministers' Sub-Group to discontinue production of the profiles to alleviate costs associated with maintaining and reading controlled load sample meters.

In both NSW and South Australia, accumulation meter controlled load energy is now settled against the Net System Load Profile (NSLP), rather than a dedicated controlled load profile.

We consider that the controlled load profile should encompass interval meter controlled load customers, unlike in prior determinations where only accumulation meter controlled load demand was included. More than half of controlled load customers will be settled on interval meters during DMO 8. Interval meter penetration will continue to increase in future determinations due to the Australian Energy Market Commission's (AEMC) *Accelerating smart meter deployment* rule change, which aims to replace all accumulation meters in the NEM with interval meters by 2030.³⁶ Retailers are also increasingly gaining the capability to activate interval meter controlled load demand flexibly, rather than following fixed schedules determined by a given DNSP, as is the case with accumulation meter controlled load. DNSPs indicated in pre-issues paper engagement that this may cause interval meter demand patterns to diverge materially from AEMO's published profiles in the near future.

³⁴ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Section 3.2: Considerations.

³⁵ AEMO, [Removal of Controlled Load Profile – NSW](#), Australian Energy Market Operator; AEMO, [Removal of Controlled Load Profile and Metering Installation Reversion Provisions – SA](#), Australian Energy Market Operator.

³⁶ AEMC, [Accelerating smart meter deployment](#), Australian Electricity Market Commission, 28 November 2024.

Therefore, we plan to use interval meter controlled load data as the basis for our controlled load profile in DMO 8 to improve the accuracy of our data and reflect the ongoing smart meter rollout.

We are consulting on whether and how we might continue to account for accumulation meter controlled load in the absence of a current controlled load profile published by AEMO. We are seeking stakeholder comment on 3 options set out below.

To inform creation of controlled load profiles for DMO 8, we have requested interval meter controlled load profiles from DNSPs in each DMO region. These profiles span 2 years from 1 October 2023 to 30 September 2025, which ensures alignment with data used for the general use load profiles.

During our engagement with AEMO and DNSPs, we identified that the interval meter dataset AEMO provides us to inform our assumed load profile for 'residential customers without controlled load' (general use) does not exclude interval meters with controlled load. Acquisition of an interval meter controlled load profile allows us to remove any residual controlled load from the general use interval meter dataset. We consider this is worth doing for DMO 8 since we expect the volume of interval meter controlled load present in the general use profile to increase as more controlled load customers switch to interval meters.

Aligning the data sources for all regions

Since AEMO continues to publish the Controlled Load Profile for Energex, it is not strictly necessary to align the data sources for the controlled load profile for Energex with the other DMO regions. However, there is merit in adopting consistency across all regions, including Energex, because:

- A consistent approach may provide greater simplicity for market participants operating across multiple regions.
- Adopting in Energex whichever new approach is applied to other regions would enable us to fully capture all controlled load customers regardless of their meter type, including interval meter controlled load customers, who are not represented by the current approach.

Options for consideration

We plan to use the interval meter controlled load profiles provided by DNSPs in all cases. However, given the absence of a current accumulation meter controlled load profile, we need to decide whether and how to account for accumulation meter customers. We discuss 3 options for doing this below.

We will evaluate these options against the following decision criteria:

- **Reflection of market outcomes** – we consider we should strive to include load profile data that is an appropriate reflection of a load profile shape a retailer would hedge against for its small customers during the DMO 8 period.
- **Data transparency** – we are aware of strong support from stakeholders to base the DMO on publicly available data (where possible), but note the trade-off that may occur, as confidential data often provides greater insights to market outcomes.

- **Longevity of the decision** – we are aware that consistency in the DMO methodology remains important to stakeholders. We will consider how any decision on load profiles may continue to be upheld as market conditions change.
- **Continuity between determinations** – we consider that we should avoid drastic changes to the methodology where possible, to minimise confusion and regulatory burden. Where available, we will aim to select options that serve as updates to the prior methodology, rather than fundamental changes to it.

Option 1: Use only the interval meter controlled load profile

Option 1 would use the interval meter controlled load profile exclusively, to represent the entire controlled load customer cohort. This would reflect the demand patterns of interval meter controlled load customers, but not of accumulation meter controlled load customers. In this option, the volume of the interval meter controlled load profile would be scaled up to the total controlled load volume consumed in the relevant distribution region so that it represents the entire controlled load customer cohort.

- **Reflection of market outcomes** – this option would accurately reflect the time-of-day demand shape of interval meter controlled load customers, but not of accumulation meter controlled load customers. Currently, accumulation meter customers still make up a significant proportion of controlled load customers. Insufficient representation of accumulation meter customers could diminish the accuracy of the simulated profile if the demand shape of interval meter controlled load is materially different to modern accumulation meter controlled load demand. However, any diminished accuracy driven by a lack of accumulation meter controlled load representation would be reduced over time as more customers switch to interval meters.
- **Data transparency** – we have received permission from all relevant DNSPs to publish the underlying data for interval meter controlled load profiles alongside our draft and final determinations.
- **Longevity of the decision** – there are no foreseen issues with implementation of this method in future determinations. The exclusive use of interval meter controlled load data would become more representative of the whole market as more customers transition to interval meters through the smart meter rollout. By 2030, the interval meter controlled load profile should represent 100% of controlled load customers.
- **Continuity between determinations** – we do not consider this to be a change to our underlying methodology. We are simply using a more up-to-date dataset with a larger sample size as the basis for our controlled load profile.

Option 2: Blend an interval meter controlled load profile with AEMO's historical accumulation meter Controlled Load Profile

Option 2 would involve blending the interval meter controlled load profile for a given region with AEMO's last published Controlled Load Profile for the same region. This would mean that the accumulation meter portion of the controlled load profile would be more than one year old, but the interval meter portion would be current. The blended profile would be weighted according to the number of customers belonging to each profile. For example, if 50% of controlled load customers in the given region are settled with an interval meter, the

volume of the interval meter profile would be multiplied by 0.5 and then scaled up as in option 1.

- **Reflection of market outcomes** – option 2 would account for demand patterns from both interval and accumulation meter controlled load customers, but would rely on outdated accumulation meter demand data. In all regions except Energex, AEMO's Controlled Load Profile is more than one year old, which could reduce its accuracy. However, in response to this concern, during recent engagement, DNSPs indicated that they have no plans to change accumulation meter activation timing. Therefore, it is unlikely that accumulation meter controlled load demand has diverged materially from AEMO's most recently published Controlled Load Profiles. Another disadvantage of this option is that it would not reflect the settlement arrangements of accumulation meter National Metering Identifiers, which are settled against the NSLP.
- **Data transparency** – AEMO's Controlled Load Profile, though discontinued, remains publicly available on AEMO's website. As with option 1, all relevant DNSPs have permitted the AER to publish the underlying data for interval meter controlled load profiles.
- **Longevity of the decision** – the data used to inform the accumulation meter component of the blended controlled load profile would grow older with each determination, potentially diminishing accuracy. However, the customer-weighted blended profile will dynamically adjust as more controlled load customers transition to an interval meter, giving more weight to the interval meter profile and less to the accumulation meter profile. Interval meters should make up almost 100% of controlled load demand by 2030, given the estimated completion date of the smart meter rollout. At that point, the accumulation meter profile would be multiplied by zero, so would have no impact on the shape of the profile.
- **Continuity between determinations** – we don't consider this to be a change to our underlying methodology. We are simply using a more up-to-date dataset with a larger sample size as the basis for our controlled load profile and blending this with the controlled load profile used in prior determinations.

Option 3: Blend interval meter controlled load profile with the NSLP

Option 3 uses the same interval meter controlled load profile as in the previous 2 options but would blend this profile with the NSLP. Unlike option 2, the accumulation meter portion of the controlled load profile in option 3 would be current, since it is represented by the NSLP. This option aims to reflect that accumulation meter controlled load is now settled against the NSLP in regions where AEMO's Controlled Load Profile has been discontinued.³⁷ As with option 2, the relative representation of each profile in the blend would be proportionate to the number of customers belonging to each profile, according to their meter type.

³⁷ Option 3 would not be appropriate in simulating the controlled load profile for Energex, where AEMO's Controlled Load Profile continues to be published and remains current. Accumulation meter controlled load customers in Energex regions are still settled against the published controlled load profile rather than the NSLP. As such, we would still blend the interval meter controlled profile with AEMO's Controlled Load Profile in Energex if option 3 were adopted.

- **Reflection of market outcomes** – option 3 would replicate settlement arrangements of both interval and accumulation meter controlled load customers by blending the interval meter controlled load profile with the NSLP. However, this would cause the blended profile to differ significantly from actual controlled load demand patterns. Controlled load typically achieves its lower wholesale cost by avoiding dispatch in morning and evening peak periods, when most NSLP demand occurs. Blending with the NSLP would cause the controlled load profile to resemble general use consumption more closely, with more volume during peak periods and less during solar and overnight periods, when controlled load typically operates. By attempting to replicate settlement arrangements, this approach produces a profile that diverges materially from the known demand shape of controlled load, likely resulting in overestimation of the controlled load WEC.
- **Data transparency** – the data informing the NSLP is published on AEMO’s website. We have received permission from all relevant DNSPs to publish the underlying data for interval meter controlled load profiles alongside our draft and final determinations.
- **Longevity of the decision** – there are no known issues with the applicability of this approach in future determinations. However, the methodology would need to be reconsidered if the NSLP in any region were to become unstable and require adjustment by AEMO, as occurred in SA Power Networks and Energex regions from 2021 to 2023.
- **Continuity between determinations** – we don’t consider this to be a change to our underlying methodology. We are simply using a more up-to-date dataset with a larger sample size as the basis for our controlled load profile and blending this with the NSLP.

Additional methods considered but not proposed

We also evaluated a fourth method, which would have used the general use profile for customers without controlled load to estimate controlled load costs. This would have resulted in the same wholesale energy cost (WEC) for both customer types. We are not consulting on this method because we do not consider it adequately satisfies the decision criteria.

Under the fourth option, the consumption of controlled load customers would be modelled using the same load profile as general use customers, effectively treating controlled load consumption patterns as identical to general use consumption patterns. This change would fundamentally alter the shape of the controlled load demand modelled in the DMO. As discussed above, most general use demand occurs during morning and evening peak periods, which controlled load profiles specifically avoid. Therefore, this method would result in a complete inversion of the controlled load demand pattern, which we consider is not an accurate reflection of market outcomes. We do not consider this an appropriate method given the availability of the more suitable options discussed above.

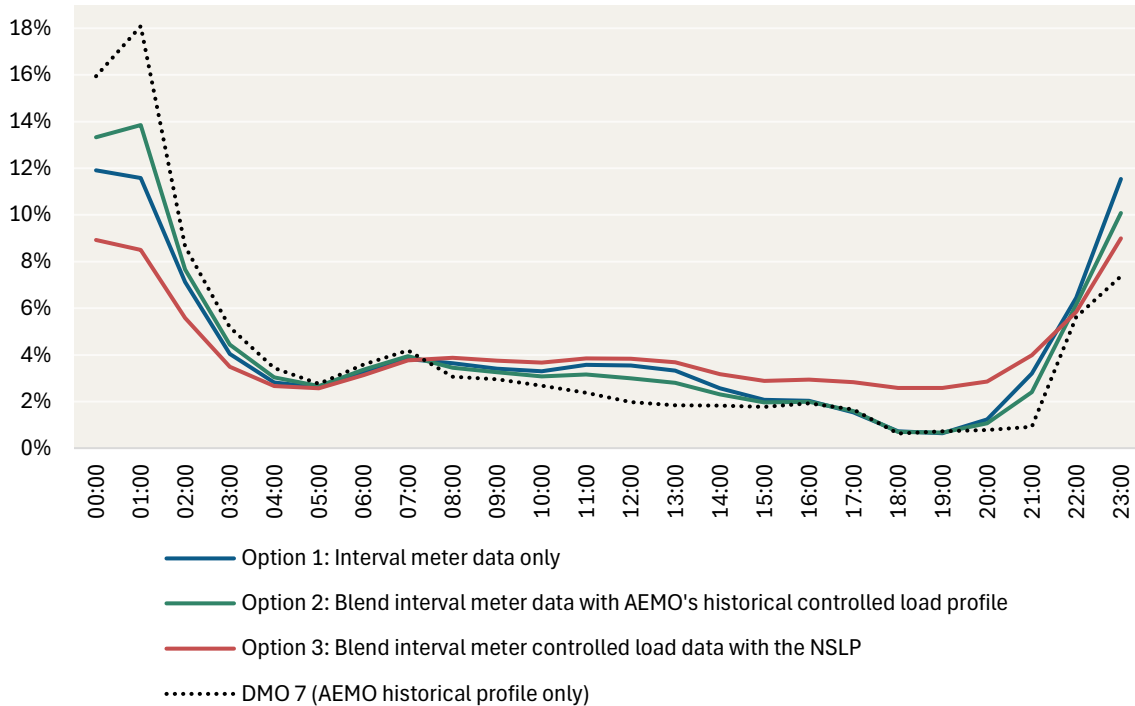
Shapes resulting from each option

Some DNSPs have provided preliminary data for the first year of the 2-year sample proposed to be used in the options above (October 2023 to September 2024). Since this period matches the span used for DMO 7, we have tested how the shape of the assumed controlled load profile would have changed under each of the options presented to assist stakeholders in their consideration of this issue (Figure 5.1 to Figure 5.3).

For all regions reviewed so far, interval meter controlled load profiles show shifting of some overnight controlled load demand to solar hours during the middle of the day. This shift is

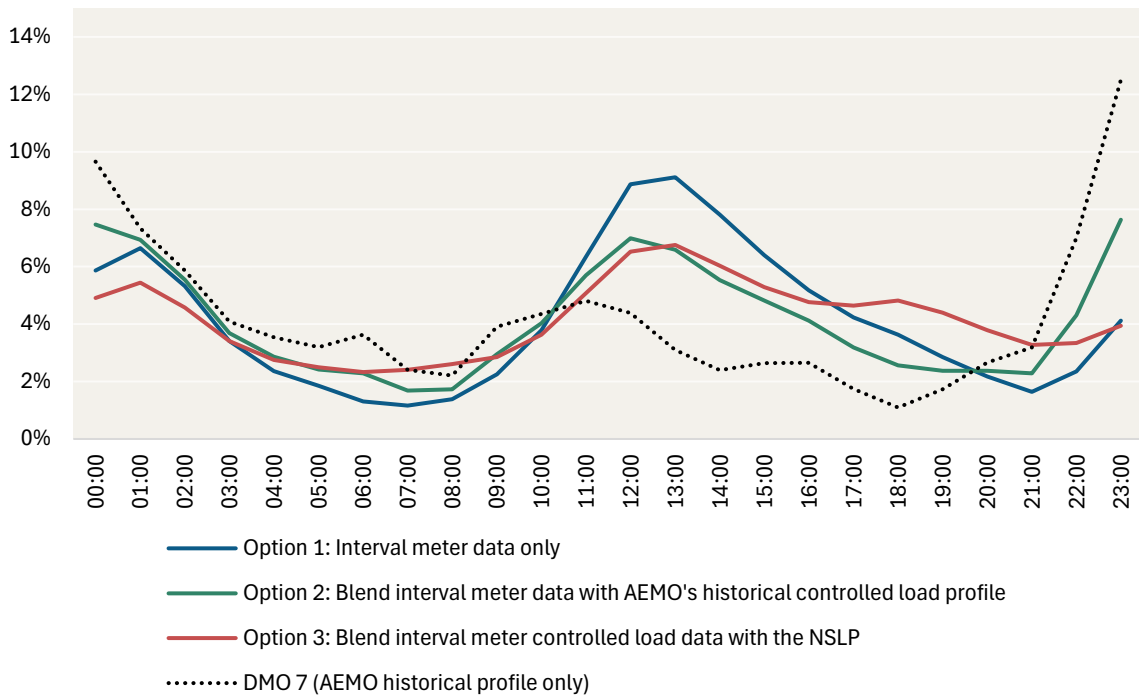
most pronounced when option 1, using exclusively interval meter controlled load data, is applied. Applying option 2, blending the interval meter controlled load profile with AEMO's historical controlled load profile, still shows the shift from overnight to midday demand but to a lesser extent. Applying option 3, blending the interval meter controlled load profile with the NSLP, also results in an increase in midday controlled load demand but additionally increases demand at peak times.

Figure 5.1 DMO 7 controlled load profile under each option, Ausgrid



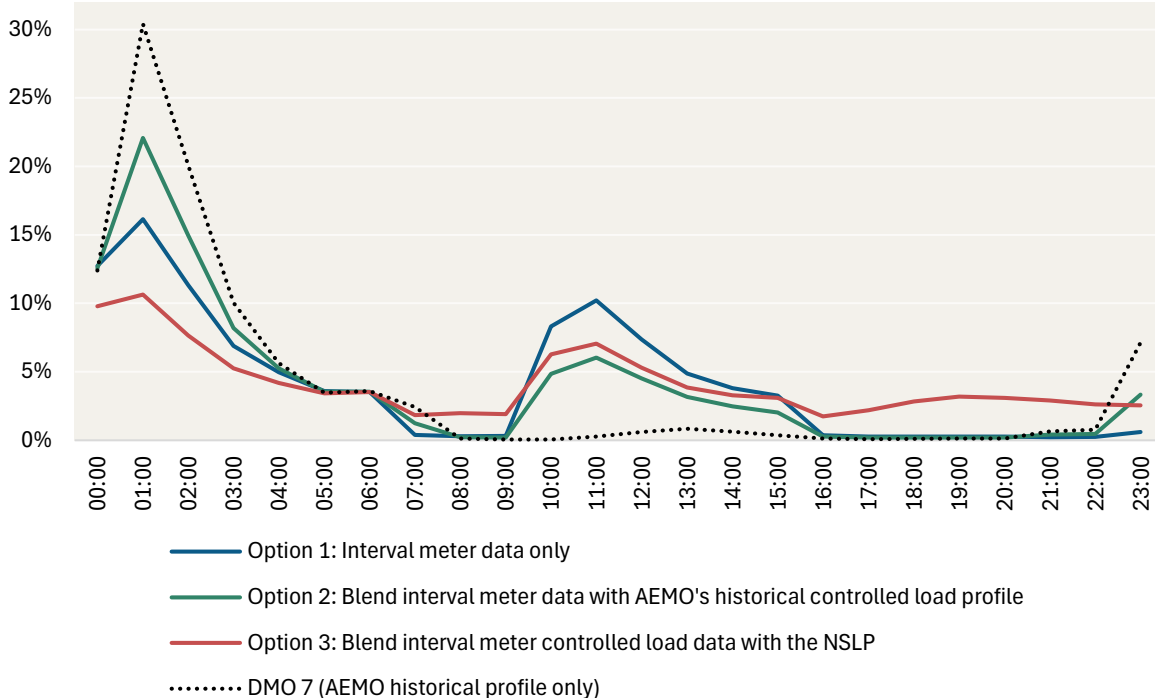
Note: Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2024. For Ausgrid, values for CL1 and CL2 have been aggregated into a single series for readability. However, these profiles will remain separate in the wholesale cost modelling.

Figure 5.2 DMO 7 controlled load profile under each option, Essential Energy



Note: Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2024.

Figure 5.3 DMO 7 controlled load profile under each option, SA Power Networks



Note: Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2024.

Question 8: Which option do you consider best meets the criteria set out above?

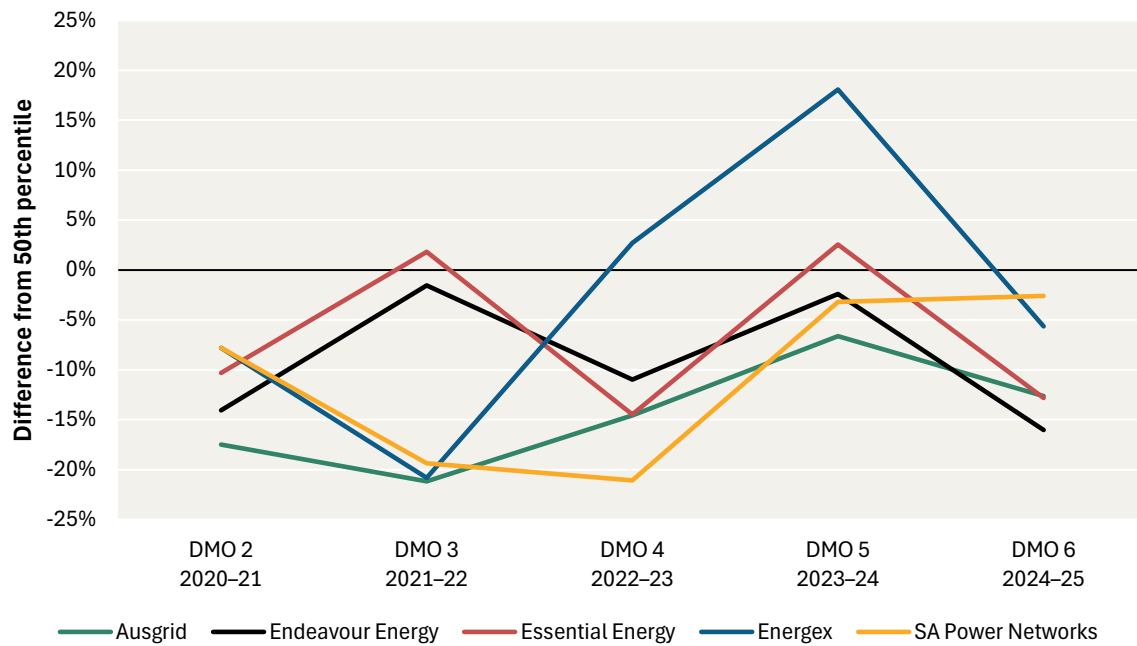
Question 9: What are your views on the application of the new approach to the Energex controlled load profile, in addition to the regions where AEMO's Controlled Load Profile is no longer published?

5.3 Percentile WEC estimate

Several submissions from retailers throughout DMO 7 called for the performance of the wholesale cost model to be transparently reviewed against actual outcomes that have occurred in the market. We have completed this back-cast analysis and our findings are detailed in *Assessing the performance of the wholesale cost model*, a supplementary report to this issues paper. The analysis calculated WECs incurred by a retailer using the hedging strategy assumed in previous DMO determinations by settling each hedging strategy against actual spot price and load profile outcomes from their respective years.

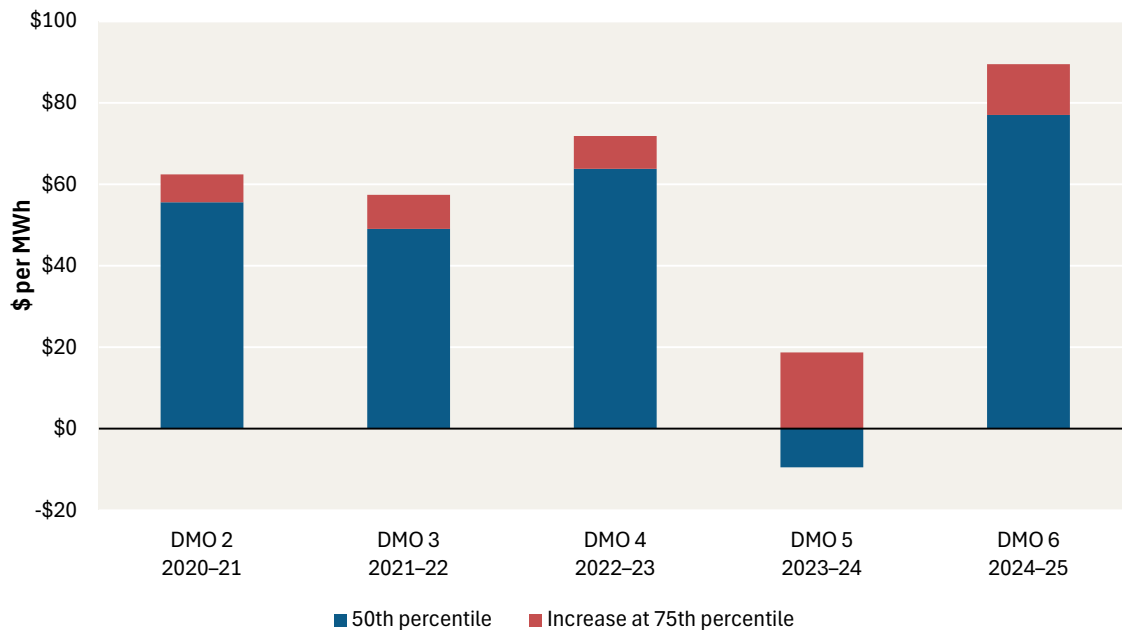
The analysis found that the 75th percentile WEC estimate has resulted in retailers over-recovering costs from standing offer customers in most years, sometimes by a significant margin. Given these findings, we are consulting on whether the 50th percentile WEC should be adopted from the distribution of WEC estimates produced by the wholesale cost modelling, rather than the 75th percentile as in recent determinations. We are considering this shift may be merited under both the current and proposed Regulations.

We have previously selected the 75th percentile WEC estimate to provide retailers with a buffer against unexpected volatility. The back-cast analysis indicated that using the 50th percentile WEC estimate would still provide that buffer without allocating disproportionate risk to consumers, as occurs at the 75th percentile. The only notable instance of underestimation of the WEC occurred in Energex in 2022–23, when cheaper gas generation driven by the Australian Government's gas price cap reduced the actual cap payout well below modelled estimates. The back-cast analysis showed that at the 50th percentile retailers using similar hedging strategies to the DMO would have recovered their costs in 84% of instances across regions and determination years (Figure 5.4).

Figure 5.4 Actual WEC difference from 50th percentile WEC estimate

Note: Zero represents the 50th percentile WEC from each DMO determination. Individual lines measure the difference between the actual WECs calculated from the back-cast analysis and the 50th percentile WEC estimates from each DMO determination.

Adoption of the 50th percentile WEC estimate would also reduce the scale of overestimation that has occurred at the 75th percentile in most years (Figure 5.5)

Figure 5.5 Recovery by the modelled retailer compared with the back-cast actual WEC, sum of all regions

Note: Zero represents the 50th percentile WEC from each DMO determination.

We also consider that the 50th percentile WEC estimate aligns more closely with the proposed requirement to consider the efficient costs to supply small customers. The 50th percentile estimate represents the median forecast outcome, meaning it compensates retailers for the expected cost of efficient hedging. Conversely, the 75th percentile results in compensating retailers for a more volatile than expected outcome, effectively applying an additional risk premium on top of the expected efficient cost to supply small customers.

Whether to include a volatility allowance if the 50th percentile WEC is adopted

We are also consulting on whether to include a volatility allowance if the 50th percentile is adopted. The purpose of a volatility allowance would be to replace the risk buffer currently provided to retailers by the 75th percentile WEC estimate.

A volatility allowance would be calculated by multiplying the difference between the 50th and 100th percentile WEC estimates by the weighted average cost of capital in a given region.

We consider that a volatility allowance may be unnecessary, since the 50th percentile has been shown by the back-cast analysis to have overestimated the WEC by an average of 6.8% across the last 5 determinations. This would suggest that an adequate risk buffer already exists at the 50th percentile. However, we acknowledge that some stakeholders may hold opposing views.

Question 10: What are the implications of adopting the 50th percentile WEC estimate instead of the 75th percentile, based on the back-cast analysis?

Question 11: What factors should we consider in determining whether a volatility allowance is necessary?

Question 12: Do you agree that the 50th percentile WEC estimate aligns more closely with the proposed requirement to consider the efficient costs to supply small customers?

5.4 New morning and evening peak contracts

The ASX introduced new morning and evening peak contracts. Similar to traditional peak contracts, these financial products allow retailers to manage their exposure to wholesale market outcomes at predetermined times of day. The new morning and evening peak contracts differ from the older peak contracts in that their prescribed times have been adapted to the peakier shape of the modern retailer load profile.

At this stage, we do not consider that the new morning and evening peak contracts have been traded at sufficient volume to justify their inclusion in the DMO 8 hedging strategy. Morning and evening peak contracts commenced trade in July 2025, but so far have seen limited traded volume. For the DMO 8 period, only 10 megawatts (MW) of evening peak contracts have been traded across all regions: 5 MW for Q2 2027 in NSW and 5 MW for Q4 2026 in Queensland. No evening peak products have been traded in South Australia. Morning peak contracts have not yet been traded in any region or period. With significantly fewer trades than there are retailers in the market, it would be incorrect to assume that a standard retail hedging strategy includes either of the new peak contracts.

It is possible that trade of the new peak products will increase in the coming months and years. Since this is the first time a new product has begun trading on the ASX while the DMO has been in place, there are no established parameters for a level of traded volumes that would justify inclusion of a new product in the hedging strategy. Therefore, we are seeking stakeholder views on the parameters we should consider for inclusion of new products in the hedging strategy.

Question 13: What parameters should we consider when deciding whether to include new products in the hedging strategy?

5.5 Time-of-use wholesale energy costs

The proposed reforms would require us to express the DMO as a tariff rather than an annual price cap, including for time-of-use offers. As discussed in chapter 3, the wholesale cost (except for NEM fees) will be allocated to the usage charge component of the tariff.

In practice, this means that a single WEC needs to be apportioned across multiple time periods. To do this, we propose to adopt an approach like that used by the QCA. This would involve calculating time-varying WECs by dividing the load profile into specified time slices (for example, peak and off-peak). The WEC for each period would then be scaled from the total WEC using the ratio of the demand-weighted price in that period to the overall demand-weighted price for the profile. This method ensures that:

- the sum of the periodic WECs is equal to the total across the demand profile
- the resulting price relativities reflect the underlying cost curve (that is, lower WECs in daylight hours and higher WECs during peak periods).

We consider this approach is an objective and transparent method to divide the WEC across prescribed time-of-use periods, but we seek stakeholder views on whether an alternative approach may be more suitable.

We would need to consider how this approach needs to be adapted for a Solar Sharer Offer. We will give this further consideration as the details of the Solar Sharer Offer are finalised.

Question 14: Do you agree with the proposed approach to estimating time-of-use WECs? Is there an alternative approach we should consider?

6 Environmental costs

Environmental schemes, at the national level and in some states, require retailers to procure energy from renewable sources and improve customer energy efficiency. The costs of complying with these schemes are incurred by retailers.

In DMO 7, the environmental costs component made up between 3% and 4% of the DMO prices set.

Environmental costs fall into 3 main categories:



The Large-scale Renewable Energy Target (LRET)
LRET costs are incurred by retailers when they acquire the necessary amount of large-scale generation certificates (LGCs) to promote long-term investment in renewable energy infrastructure.²⁵



The Small-scale Renewable Energy Scheme (SRES)
SRES costs are incurred by retailers when they acquire the necessary amount of small-scale technology certificates (STCs) to support small-scale renewable energy infrastructure.²⁶



Jurisdictional-based schemes
Includes policies encouraging improving energy efficiency 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. There are schemes specific to NSW and South Australia.²⁷

From DMO 2 to DMO 7 we have used a market-based approach to environmental cost estimations with updates to new and amended schemes.⁴¹

³⁸ CER, [Large-scale Renewable Energy Target](#), Clean Energy Regulator.

³⁹ CER, [Small-scale Renewable Energy Scheme](#), Clean Energy Regulator; CER, [Small-scale technology certificates](#), Clean Energy Regulator.

⁴⁰ In NSW, these are the [Energy Savings Scheme](#) (ESS) and the [Peak Demand Reduction Scheme](#) (PDRS), both run by the NSW Government. In SA, there is the [Retailer Energy Productivity Scheme](#) (REPS) set out by the South Australian Minister and administered by the [Essential Services Commission of South Australia](#) (ESCOSA)

⁴¹ AER, [Default Market Offer prices Final determination 2025–26](#), Australian Energy Regulator, pp. 50–51, sections 6.1 & 6.3.

The current Regulations require us to consider all costs associated with complying with Commonwealth and state/territory laws when determining a DMO price.⁴² Similarly, the proposed Regulations require the AER to consider the efficient costs to supply customers.⁴³

Overall, we consider our current approach remains reasonable for DMO 8 under both the current Regulations and the proposed Regulations and are not consulting on any changes to this aspect of the methodology.

⁴² Regulations, s. 16(4)(c)(iii).

⁴³ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 2.

7 Retail and other costs approach

Retail costs are the costs retailers incur in serving their customers, as well as the costs associated with acquiring new customers and retaining current customers. Since DMO 4 we have used a ‘cost-stack’ methodology to separately determine retail costs and retailer margins. In DMOs 4, 5 and 6 we considered a wide range of costs incurred by retailers. This retail cost information was published by the ACCC as part of its Inquiry into the National Electricity Market.

To establish a broader and more diverse sample of retailer costs, we developed our own retail cost information dataset in DMO 7. This expanded the dataset to include more retailers selling to residential and small business customers in DMO regions to provide a better understanding of the spectrum of retailers’ costs and key drivers of those costs, and the variation in costs between larger and smaller retailers.⁴⁴

This chapter discusses our refinements to the retail cost information request for determining retail costs in DMO 8. Based on the DMO framework review and proposed amendments to the Regulations, we are consulting on a set of approaches used to quantify various retail cost subcomponents, including the costs to serve and customer acquisition and retention costs. We also invite stakeholder feedback on whether bad debt should be allocated as a fixed daily supply charge, a variable usage charge or a combination of both.

The recommended reforms shift the emphasis to setting a regulated price:

- at the efficient costs to supply small customers on standing offers
- that includes modest costs associated with customer acquisition and retention.

Given that these changes represent a departure from the current Regulations of setting a reasonable total annual price for selling electricity allowing reasonable profit, we consider that this warrants consideration of a change in methodology for setting these costs.

7.1 Recent refinements to improve the quality of our inputs

For DMO 8, we have refined our information request such that the retail cost information sought by both the AER and the ESC in setting the VDO are harmonised. This approach aims to help reduce regulatory burden on retailers responding to both sets of requests, assist the AER to streamline its collection and assessment process, and improve the quality and transparency of data that we collect.

Key refinements to our information request include:

- definitional consistency with other regulators in instances where similar information is sought

⁴⁴ AER, [DMO 7 draft determination](#), Australian Energy Regulator, 11 October 2024, pp. 65–72.

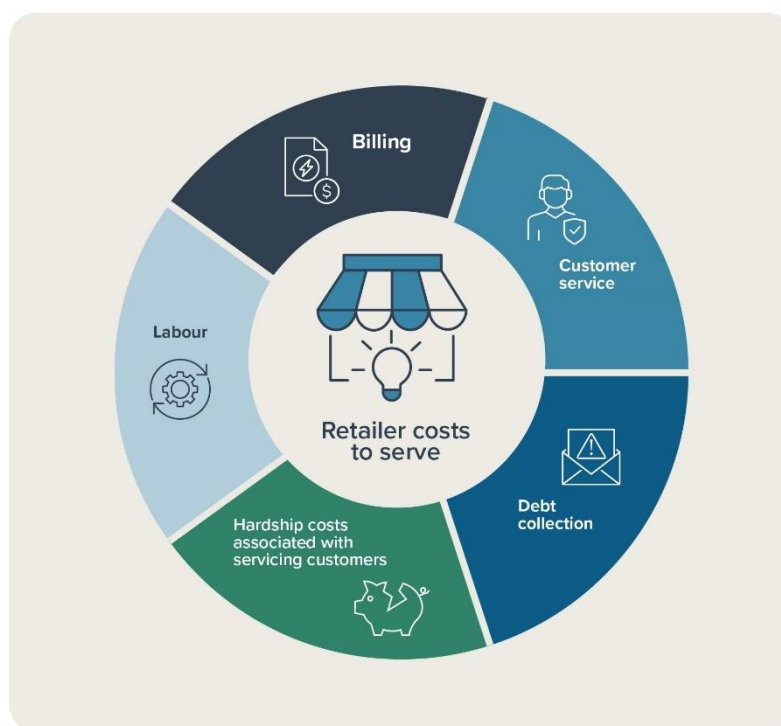
- excluding any fines and penalties incurred, costs associated with retailer offerings outside the scope of the DMO or unrelated to selling electricity, and other costs accounted for elsewhere in the DMO cost stack
- requiring retailers to identify and explain any significant cost movements across any retail and other cost categories
- formally identifying and reviewing the 3 biggest ‘other retail costs’⁴⁵
- incorporating smart meter costs in our information request, as well as specific cost drivers to improve the reporting transparency of costs incurred by retailers.

A number of these refinements ensure that only reasonable costs are included in the retail and other cost stacks.

On 8 September 2025, we commenced the process of obtaining retail and other cost data from a cohort of 24 retailers that sell electricity to over 1,000 small customers across all DMO regions. This information request was issued to retailers that represent approximately 98.9% of residential and 98.1% of small business customers in DMO regions.⁴⁶

7.2 Cost to serve

Retail costs to serve reflect a range of costs incurred by retailers, including:



⁴⁵ These ‘other costs’ represent retail costs that do not fall within any one of the main retail cost subcomponents, including costs to serve and costs to acquire and retain customers.

⁴⁶ Proportions are based on Q3 2024–25 retail performance data. In DMO 7, retail and other cost data was requested from 26 retailers. However, this number was reduced to 24 based on individual retailer circumstances, including the likelihood of market exit.

In DMO 7, we applied a customer-weighted average across all retailers' cost data to quantify the costs to serve. In determining these costs, we identified significant outliers within the retail and other cost dataset and excluded them from the retail cost stack. This approach also aligned with the VDO's objective in setting efficient retailer costs, including the costs to serve.

Setting the DMO based on efficient costs has implications for each element of the DMO cost stack, including the costs to serve. Under the reforms, the AER would be required to adopt an approach and methodology that best quantifies the efficient costs to supply small customers on standing offers and achieves the DMO objective of a fair, trusted and reasonable price.⁴⁷

We are considering 2 options for quantifying costs to serve to reflect the recent DCCEEW reforms. All options will be applied by customer type and DMO region.

Option 1: Apply the standing offer customer-weighted average costs to serve from all retailers

Option 1 involves applying a standing offer customer-weighted average to all retailers' costs to serve data. Under this approach, costs to serve data of all retailers is weighted by the number of standing offer customers for each customer type within each DMO region. This approach considers the proposed DCCEEW reforms, where the AER will be required to set the efficient costs to supply the types of customers on standing offers.

For this option, a key drawback is that it is heavily influenced by the cost structures of the Big 3 retailers, who have a significant share of standing offer customers. This may see the results from this approach skewed towards the costs to serve of the Big 3 retailers.⁴⁸ However, this approach continues to capture the costs of the broader retail market, including new and smaller retailers.

Option 2: Maintain the current approach of applying the customer-weighted average costs to serve of all retailers

Option 2 proposes to maintain the approach used in DMO 7, in which we applied a customer-weighted average of the costs to serve across all retailers, with outliers and other costs (such as legal provisioning or costs accounted elsewhere in the DMO cost stack) being removed.

Option 2 better reflects economies of scale compared with other measures like the simple average or median and is less susceptible to fluctuations in future datasets – for example, if new retailers that sell electricity to over 1,000 small customers are added to the retail and other cost dataset.

The main limitation is that it does not specifically target standing offer customers. This approach is more applicable to all customers, not just customers on standing offers, and the DMO framework review outcomes and proposed Regulations outline that we should consider the efficient costs to supply for small customers on standing offers when determining the DMO.

⁴⁷ DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Executive summary: Recommendation 2.

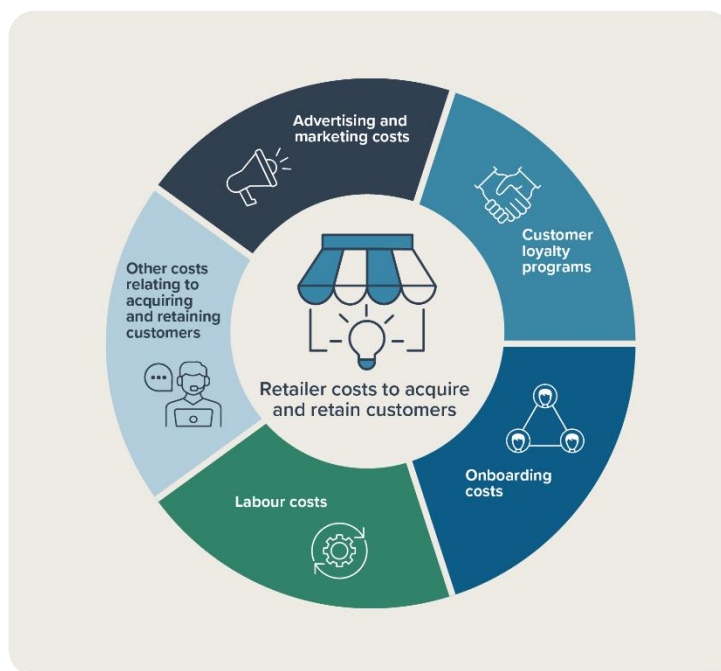
⁴⁸ Big 3 retailers include EnergyAustralia, AGL and Origin Energy.

If the Regulations are not amended and in force for DMO 8, we will maintain a weighted average approach to determining retail costs to serve.

Question 15: How can we best define and calculate the efficient costs to serve for small customers on standing offers?

7.3 Costs to acquire and retain customers

Costs to acquire and retain customers is made up of:



In DMO 7, we applied a customer-weighted average of the costs to acquire and retain customers. This approach was undertaken within the context of the Regulations, which require that we determine a reasonable annual price to supply electricity.

The proposed amendments to the Regulations would require the AER, when determining the DMO, to take into account ‘modest’ costs associated with customer acquisition and retention.

The outcomes paper does not provide a definition for ‘modest’. Macquarie Dictionary defines modest as ‘moderate’.⁴⁹ However, the outcomes paper discusses that the appropriate level of costs to acquire and retain customers should reflect:

- that retailers will incur some costs in managing the relationship with standing offer customers and that some of these costs may be incurred in enhancing consumer experience, such as the development of comparison tools – for example, retailers will incur some onboarding costs for standing offer customers and incur ongoing costs related to customer service

⁴⁹ [Macquarie Dictionary Online](#) 2025, Macquarie Dictionary Publishers, an imprint of Pan Macmillan Australia Pty Ltd.

- the costs incurred by retailers in supplying standing offer customers
- the extent and nature of such costs associated with those customers being protected by the DMO.

The outcomes paper recommends the AER evaluate whether costs to acquire and retain customers are essential for the retail supply, the benefits of such costs and whether such costs are not already captured in other components to the DMO methodology, such as retailer operating costs.

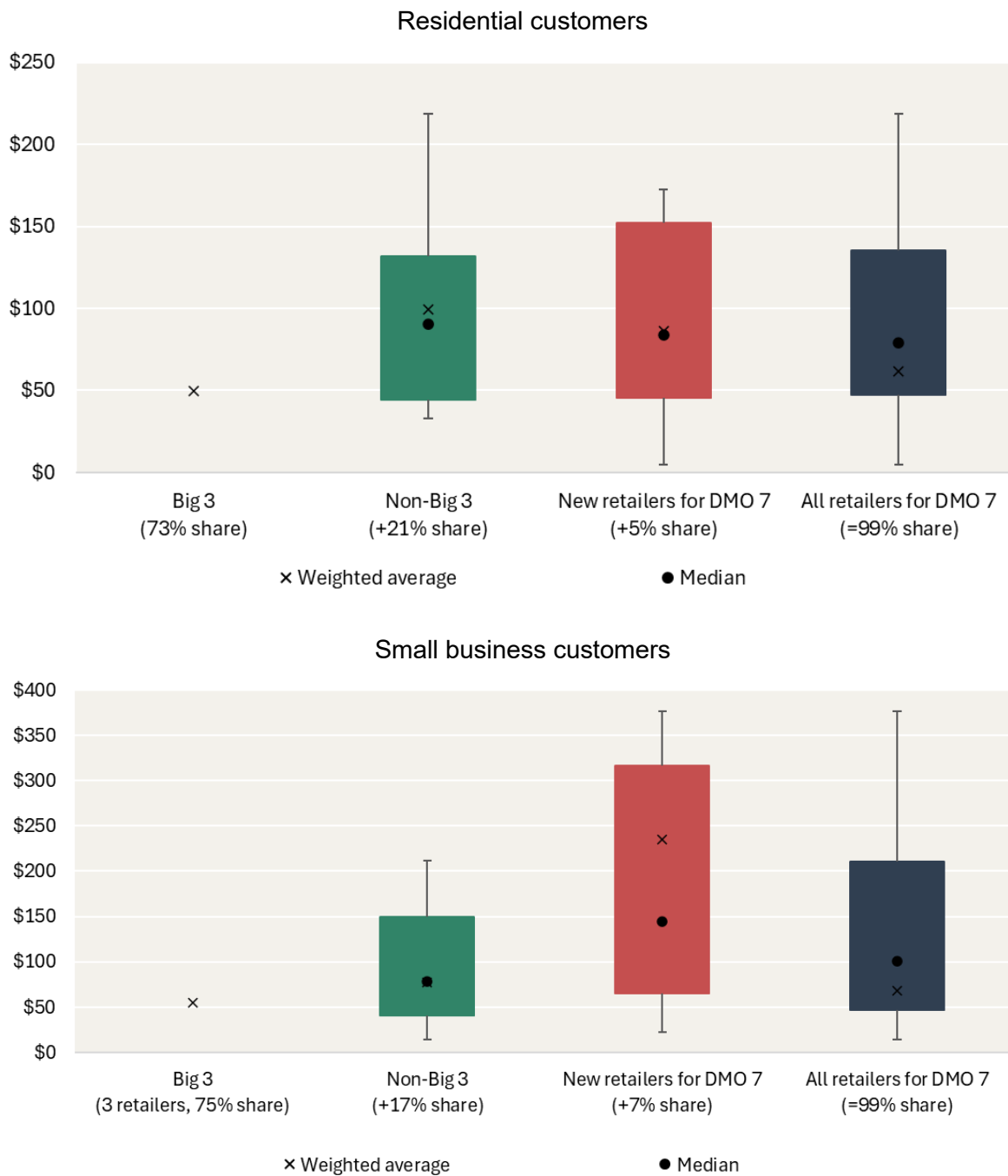
Given these proposed reforms, we are considering 2 options to quantify modest customer acquisition and retention costs.

Option 1: Apply the standing offer customer-weighted average costs to acquire and retain from all retailers

We are cognisant that the AER must consider the types of small customers on standing offers. This option benchmarks the costs of acquiring and retaining customers using the standing offer customer-weighted average across all retailers. Therefore, an advantage of this approach is that it would more closely reflect the costs to acquire and retain customers of retailers serving standing offer customers, which is required under the new mandatory considerations. These customers are generally less active in the market and are predominantly served by the larger retailers, such as the Big 3, which account for approximately 90% of standing offer customers in DMO regions. Given the Big 3 retailers' large proportion of standing offer customers, the results will be skewed towards their costs to acquire and retain, which are relatively more 'modest' compared with the current approach of adopting the customer-weighted average costs to acquire and retain across all retailers.

Figure 7.1 (reproduced from our DMO 7 draft determination) demonstrates that the costs to acquire and retain customers of the Big 3 retailers are lower than other retailers, and are also below the overall average of all retailers.

Figure 7.1 Distribution of costs to acquire and retain customers (\$/customer), by customer type, all DMO regions, including GST



Option 2: Apply the ESC's approach to modest costs to acquire and retain customers

The outcomes paper notes that allowing for the inclusion of modest customer acquisition and retention costs aligns with the approach in Victoria.

In setting the VDO, the ESC currently adopts a modest allowance for costs to acquire and retain customers, as required under its regulatory framework.⁵⁰ However, the ESC is not

⁵⁰ Clause 12(4)(d) and Clause 12(6) of the Electricity Industry Act (pricing order).

explicitly required to consider only the customer acquisition and retention costs associated with standing offer customers.⁵¹

In its proposed approach to determining the first VDO, it observed that the then current retailer costs to acquire and retain customers appeared to have increased at a faster pace than switching rates. It considered that current costs to acquire and retain customers expenditure was a zero-sum game, in which retailers increased spending was directly in response to competitors increased spending. Since the first VDO, the ESC has applied a historic NEM-wide benchmark that predated the increase in expenditure.⁵²

This benchmark is the weighted-average 2013–14 costs to acquire and retain in the NEM, reported in the ACCC’s Retail Electricity Pricing Inquiry report, and is adjusted for inflation during each VDO review to maintain the value of the benchmark in real terms. If we adopted this historic benchmarking approach to setting ‘modest’ costs to acquire and retain, we would use the same 2013–14 NEM-wide value indexed for inflation.

Compared with option 1, this approach reflects a lower estimate of acquisition and retention costs because it is approximately 27% below the weighted-average acquisition costs reported by Victorian retailers.⁵³ Additionally, it would result in consistency in approaches across DMO regions and Victoria.

A consideration for DMO regions is that it is based on historical NEM data, which may not accurately reflect current market conditions or the true costs incurred by efficient retailers in 2026–27 or in future DMO periods.

If the Regulations are not amended and in force for DMO 8, we will maintain a weighted average approach to determining retail costs to acquire and retain.

Question 16: How can we best define and calculate a modest cost to acquire and retain customers?

7.4 Bad debt

We consider bad debt costs to be a relevant matter that we must have regard to⁵⁴ and that represent costs retailers incur when writing off unpaid bills.

For DMO 8 we refined our retail cost information request issued to retailers by:

- seeking only historical ‘actual bad debt’ that had been written off in the financial years 2022–23, 2023–24 and 2024–25
- updating our definition used in the cost notice – ‘actual bad debt’ is now defined as ‘the amount of accounts receivable / invoices payable by customers in the financial reporting

⁵¹ The ESC is required to consider the efficient costs to run a retail business, not solely the costs of supplying the subset of standing offer customers. [Fair Pricing in the Energy Market: Terms of Reference for the Essential Services Commission](#), 21 December 2018.

⁵² Essential Services Commission, [Victorian Default Offer to apply from 1 July 2019](#), 3 May 2019, pp. 75–76.

⁵³ Essential Services Commission, [Victorian Default Offer 2024-25 Final Decision Paper](#), 20 May 2024, p. 48.

⁵⁴ Regulations, s 16(4)(d).

period to which this notice relates, which the company has, in the said relevant financial year, actually identified and written off as being uncollectable.’ Therefore, such debt is not based on the accounting bad debt provisions in retailer accounts.

We are consulting on whether bad and doubtful debt should be a fixed or variable component of the DMO price that scales with electricity consumption.

The DMO framework review recommended the DMO be expressed as a tariff cap for common standing offer types. Under this expression, bad debt can be wholly allocated as a fixed or variable cost, or a combination of the two. Bad debt is related to bill amounts, and it may be more appropriate to recover bad debt from the variable cost because this component is the most significant component in bill amounts. However, changing the methodology would introduce some complexity to setting the DMO.

Option 1: Allocate bad debt as a fixed cost component of the DMO

Option 1 treats bad debt as a fixed cost on a dollar-per-customer basis. A benefit of this approach is that it is relatively simple to implement as a cost component of the DMO. It is also consistent with the approach undertaken in previous DMO determinations, where we were required to set an annual reasonable price. Other regulators, such as the ESC, also classify bad and doubtful debt as a fixed cost in their retail operating cost stack.

A key drawback of this approach is that it implicitly assumes that across all customers, the likelihood of incurring debt is the same at different consumption levels. Treating bad debt as a fixed cost may potentially overcharge low usage standing offer customers if their debt levels are relatively low.

Option 2: Allocate bad debt as a variable cost component of the DMO

Option 2 treats bad debt as a variable cost that scales with electricity consumption. That is, it assumes that those standing offer customers with high usage levels would represent more revenue at risk of being written off as bad debt. However, recovering bad debt entirely from the variable component may over-recover bad debt from higher-than-average energy users and overlook the risk that low usage customers may face challenges paying their fixed electricity costs.

While scaling bad debts may be more appropriate under a new tariff pricing structure, adopting this approach would depart from how other regulators price bad and doubtful debt.

Option 3: Allocate bad debt as a combination of fixed and variable cost components of the DMO

Option 3 treats bad debt as a combination of fixed and variable cost components of the DMO. This hybrid approach recognises that standing offer customers may face a similar risk of incurring bad debt (fixed cost component) and that higher consumption may correlate with higher levels of debt (variable cost component). Under this option, we propose to express bad debt as a percentage of reported retailers’ total billed amounts then apply it equally across the fixed and variable cost components of the DMO.

Option 3 is likely to result in the most accurate recovery of bad debt costs among varying usage amounts, but it is more complex than a fixed bad debt cost.

If the Regulations are not amended and in force for DMO 8, we will maintain a weighted average approach to determining bad debt, with outliers and other costs (such as legal provisioning or costs accounted elsewhere in the DMO cost stack) removed.

Question 17: What is the appropriate split of bad debt across fixed and variable components that best reflects the propensity for bad debt to arise?

7.5 Smart meter costs

For smart meter costs, we are maintaining our approach of including a cost of capital allowance to account for the projected shortfall in the smart meter allowance at the midpoint of DMO 8 due to additional smart meters being installed. To estimate retail costs across the DMO 8 period, a forecast consumer price index (CPI) will be applied using the Reserve Bank of Australia's inflation forecasts for 2025–26 and 2026–27.

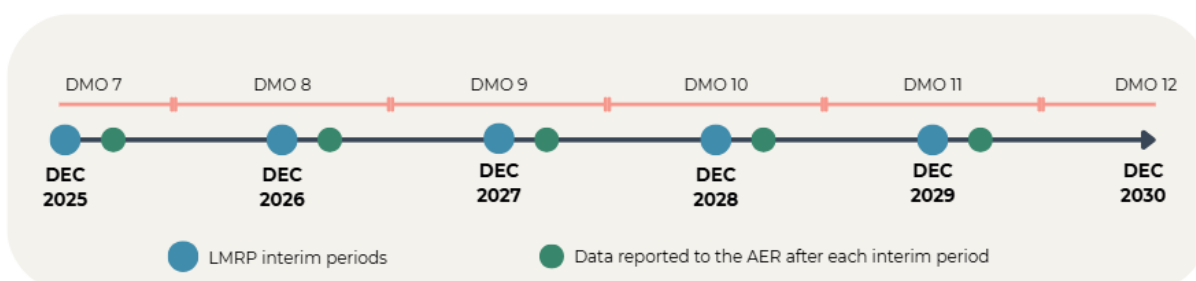
Unlike in DMO 7, where we issued voluntary data requests for actual and projected numbers as well as smart meter costs, for DMO 8 we have included the smart meter request in our formal retail costs information request. Allowing both sets of costs to be defined in one request ensures they are mutually exclusive and aims to avoid double counting of costs. This means that the smart meter dataset has expanded from 11 retailers in DMO 7 to 24 retailers for DMO 8.

Due to broadening the dataset from 11 retailers to 24 retailers, we propose to remove statistical outliers. This approach would be consistent with our approach in DMO 7, where we removed significant outliers from the calculation of the weighted average retail costs.

7.5.1 Legacy Meter Replacement Plans

The AEMC made the Rule that all legacy meters currently maintained by DNSPs in the NEM be replaced by a smart meter by 1 December 2030.⁵⁵ To facilitate a smooth transition, each DNSP consulted with affected stakeholders to develop legacy meter replacement plans (LMRP), detailing the meter replacement schedules in accordance with the LMRP objectives and principles.

Figure 7.2 Legacy meter replacement plan interim period timeline against DMO determinations



⁵⁵ AEMC, [National Electricity Amendment \(Accelerating Smart Meter Deployment\) Rule](#), Australian Energy Market Commission, 28 November 2024, p. 2.

The final LMRPs have been published on the AER website.⁵⁶ After consideration of the relevant plans for DMO DNSPs, we have concluded that the proposed rollout of smart meters for each interim period is best placed as a crosscheck on the retailer's individual projections they report, rather than used to calculate the cost of capital allowance. This is due to a risk of over or underestimating the cost of capital allowance if the number of actual installations differs from the target set in the LMRP for the interim period.

In DMO 9 we will be able to consider retailers' compliance with the LMRPs after the first interim period is complete (1 December 2025 to 30 November 2026).

⁵⁶ See the full list of LMRPs at AER, [Decisions](#), Australian Energy Regulator.

8 Retail margin and competition allowance

The current Regulations require us to set a reasonable per-customer annual price and have regard to the principle that retailers should be able to make a reasonable profit in supplying electricity.⁵⁷

DMO 1 was set at the midpoint between the median market offer and the median standing offer. We considered this price point, which was higher than the typical market offer, would allow retailers to achieve a reasonable profit as well as leaving room for competition. For DMO 2 we calculated a ‘residual’ amount, accounting for both retail costs, margins and room for competition by subtracting wholesale, network and environmental costs from the DMO 1 price, and indexed with CPI to preserve the real value. For DMO 3 we continued to index this residual.

In DMO 4 we decided to set separate retail costs and retail allowance components. We considered this approach provided greater transparency on cost drivers and allowed stakeholders to understand the AER’s assumptions about retailers’ costs and as well as the amount of profit margin available to retailers in the DMO price. We determined the retail allowance by examining the total amount of implicit margin and allowances for competition available in the DMO 1 and 3 prices across all DMO regions after accounting for typical retail costs. The retail allowance was set to reflect a return on retailer risk, allow for differences in retailers’ costs and provide additional room for competition.⁵⁸ We used this same approach in DMO 5, with some adjustment to the level of margin across regions.

Since DMO 6, we have split the retail allowance into separate retail margins and competition allowance components. This enabled greater transparency on these individual components and helped us express how we were having regard to electricity affordability and cost-of-living pressures, which we considered to be relevant in determining the DMO.

8.1 Efficient margins

The DCCEEW reforms have material implications on the quantum and form of the retail margin, and we invite stakeholder feedback on these impacts.

8.1.1 Quantifying efficient retail margins

In prior DMO determinations, retail margins were set to reflect the return on retailer risk in other components of the DMO cost stack and allow retailers to achieve a reasonable profit.

However, the recommended reforms remove this consideration and instead require us to set the DMO based on the efficient costs of supplying electricity to small customers on standing offers. Therefore, it is necessary to re-examine the quantum or level of retail margins.

⁵⁷ Regulations, s. 16(4)(b). Note that under the DCCEEW review recommendations this principle is set to be removed in the amended Regulations.

⁵⁸ The DMO prices also include a separate allowance for the costs of competition because they include the average costs to acquire and retain customers.

To reassess these retail margins, we plan to consider several sources of data and information, similar to the approach undertaken in DMO 7 for residential customers (both with and without controlled load) and small business customers. This involves considering:

- retailers' average EBITDA retail margins using their reported 2024–25 retailer cost data
- retail margins inferred from the ACCC's customer-weighted average annual prices based on their upcoming December 2025 Inquiry into the NEM report and DMO 7 costs
- retail margins inferred from advertised market offers and DMO 7 costs
- regulatory decisions from other jurisdictions
- stakeholder submissions to the issues paper and draft determination.

In addition to assessing the appropriate level of an efficient margin under these approaches, we are also exploring alternative approaches using existing data sources and other methodologies as described below.

Expected returns approach

The expected returns approach estimates the minimum retail margin required to compensate equity investors in a notional electricity retailer for the systematic or non-diversifiable risk they bear.

This approach has been undertaken to quantify an efficient margin numerous times, including by Frontier Economics for the ESC in 2019 and by the ACT Independent Competition and Regulatory Commission (ICRC) in 2024. Analysis from Frontier Economics resulted in a range between 4.5% and 5.9% of total revenue, with a midpoint of 5.2%.⁵⁹

A key challenge with this approach is determining the set of parameters to be used, including the weighted average cost of capital, standard deviation of market returns, non-volume-related costs and the standard deviation of gross domestic product (GDP) growth. Given that some of these parameters are highly subjective and are likely to be subject to debate, we do not envisage that such an approach to determine efficient margins specifically for DMO tariffs, derived from parameters and assumptions specific to DMO regions, would be adopted for DMO 8.

However, in its 2025–26 VDO determination, the ESC noted that when expected returns approaches are based on broader Australian market conditions and are not jurisdiction-specific, they can be appropriately applied across different regulatory settings, including Victoria.⁶⁰ That is, the assumptions and parameters applied by Frontier Economics in their advice to the ESC and ICRC were not specific to the economic conditions within Victoria or the ACT and nor were they specific only to retailers selling to customers in Victoria or the ACT. This indicates that the margins derived from this approach are equally applicable to retailers selling to customers in DMO regions. While we do not intend to replicate the same methodology, we consider that these outcomes of the expected returns approach, and the

⁵⁹ Frontier Economics, [Retail electricity price investigation 2024-27](#), 23 November 2023, p. 62.

⁶⁰ Essential Services Commission, [Victorian Default Offer 2024-25 Final Decision Paper](#), 20 May 2024, pp. 61–62.

margin advice provided to ESC and ICRC, to be a valuable input for determining efficient margins in DMO 8.

Using retailers' cost data

As discussed in section 7.1, we will analyse the 2024–25 financial data from retailers collected through our formal retail cost information request. A key benefit of the retailer cost data is that it contains data on the actual margins achieved by retailers within competitive markets. This analysis will consider EBITDA data across residential and small business customers, expressed as a percentage of retailers' revenue.

Under the previous DMO determinations, we considered the weighted-average margins achieved by all retailers responding to the information request to assess whether the 6% and 11% margins remained reasonable. However, the DMO reforms will require us to have regard to efficient margins and costs of supplying customers on standing offers. This may mean it is appropriate to give greater weight to the margin information provided by retailers with greater proportions of standing offer customers, such as considering the standing offer customer-weighted average of retailer margins. However, the current margins of standing offer customers could tend towards 6% and 11%, reflecting the margins in the current DMO that predates the reforms to the Regulations, and may not be a suitable basis to determine efficient margins under the proposed reforms. We are seeking stakeholder feedback on how to best consider this data when setting efficient retail margins.

Small business margins

In previous DMO determinations, we have separated residential and small business margins to meet the requirement in the Regulations that retailers can make a reasonable profit for each separate customer type.

In previous determinations we have considered that small business customers could present greater risk to retailers and that an 11% margin would be reasonable given this greater risk. Small business customers:

- have a greater prevalence of debt (3.6 per 100) relative to residential customers (3.0 per 100 customers)
- have a greater average debt per instance of debt (\$2,297 for South Australia, \$2,334 for South East Queensland and \$3,016 for NSW) relative to residential customers (\$1,825 for South Australia, \$1,234 for South East Queensland and \$1,455 for NSW).

DCCEE's proposed reforms would result in close alignment of the objectives of the DMO and the VDO as set by the ESC.⁶¹ The reforms introducing the mandatory consideration of the efficient costs to supply customers (including margin) also align with OTTER (Office of the Tasmanian Economic Regulator) and ICRC, which set prices based on efficient costs.⁶² These regulators apply the same margin for regulated residential and small business tariffs and prices, which are significantly lower than the 11% margin that we have previously

⁶¹ DCCEE, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, Section 3.1: Considerations.

⁶² OTTER, [2025 Regulated Retail Electricity Pricing Investigation - Final Report](#), Office of the Tasmanian Economic Regulator, May 2025, p. 1; ICRC, *Final Report: Retail Electricity Price Investigation 2024-27*, Independent Competition and Regulatory Commission, 23 May 2024 pp. 1–2.

considered an appropriate value for a ‘reasonable margin’ for a small business customer. This does not appear to have disincentivised retailers from selling to the small business segment nor resulted in fewer choices for small business customers than residential customers.⁶³

We consider that it may be appropriate for efficient small business margins under the proposed reforms to be a lower value than the 11% reasonable margin used in prior DMOs. A principle of efficient margins is that the margin should only compensate retailers for risk not accounted for elsewhere in the regulated price.⁶⁴ As discussed in chapter 7, we have sought 3 years of historic costs arising from writing off bad debt separately for residential and small business customers from 24 retailers. We consider that these bad debt allowances should account for the differential in debt risk between these customer types. As this risk would be accounted for in the bad debt allowance, a higher small business margin would not be required under an efficient margin approach. It may be appropriate for the small business margin to approach the 6% residential margin, similar to the regulatory decisions of the ESC, ICRC and OTTER, which apply uniform margins for both customer types.

We are seeking stakeholder feedback on whether a lower value should be adopted for an efficient small business retail margin.

8.1.2 Form of the retail margins

Under the DCCEE reforms, the DMO is to be expressed as a tariff rather than an annual price at set model usage.⁶⁵

Under a tariff-based pricing structure, we are seeking stakeholder feedback on the most appropriate way to express the retail margin. Specifically, we are considering whether the retail margin should continue to be expressed as a fixed percentage across the total DMO cost base, or whether it should include both fixed dollar and variable percentage components.

Percentage approach

As noted previously, in DMOs 6 and 7 we applied the retail margin as a percentage of total DMO costs.

Presenting the retail margin in this form has several benefits. A retail margin, expressed as a percentage, enables consistent comparison of margins over time and across prior DMO determinations. This is also a simple and transparent presentation of the margin. If this approach is adopted, this would promote regulatory certainty and continuity between DMO determinations.

⁶³ Since the introduction of the VDO, market concentration in Victoria as measured by the Herfindahl-Herschman Index has remained stable. Victoria is observed to be the least concentrated region in the NEM. See, ACCC, *Inquiry into the National Electricity Market Report December 2024*, Australian Competition and Consumer Commission, December 2024, pp. 60–61.

⁶⁴ See CI 12(7) of the Order in Council made under section 13 of the Electricity Industry Act 2000 and published in the Victorian Government Gazette No. S 208 on Thursday 30 May 2019.

⁶⁵ These tariffs would still be converted into a maximum annual bill at set model usage levels for compliance purposes.

However, a key limitation is that it can amplify absolute dollar increases in DMO prices if any underlying DMO cost components increase in value.

Hybrid approach

The retail margin can also be applied into a fixed dollar amount and percentage of DMO costs. This hybrid approach is used by other regulators such as OTTER and ICRC.

Under a hybrid approach, a portion of the retail margin is applied as a fixed dollar amount and indexed with CPI over time, while the remainder is applied as a percentage to the cost components, which will vary from year to year. Depending on the allocation of fixed variable margins, if a larger proportion of the retail margin is applied as a percentage to variable cost components, then the overall margin is more sensitive to underlying costs. The dollar amount recovered by retailers would be greater if the cost stack increases, and lower if the cost stack decreases. For example:

- The OTTER applies a uniform retail margin of 5.25%, where 50% of the margin is fixed, and 50% is variable. The fixed proportion of the margin is based on 5.25% of the average of Aurora Energy's approved costs (excluding the margin) over the past 5 years and the variable proportion is based on 5.25% of approved costs in the current year.⁶⁶ The fixed dollar component of the retail margin was decided to be indexed by the Hobart CPI in each of the second and third years of the next regulatory period.⁶⁷
- In its 2024–27 determination, the ICRC adopted a retail margin of 5.5% and applied a hybrid 50:50 weighting for the dollar amount retail margin and the percentage retail margin.⁶⁸ Similar to OTTER, the ICRC uses a 5-year average of costs and indexes the dollar amount with CPI across 2024–27.⁶⁹

Frontier Economics was engaged by the ICRC and explored the impact of using either a percentage margin or a dollar margin when wholesale energy costs increase and decrease. Frontier Economics concluded that an equal weighting to both percentage and fixed-dollar term margins would provide appropriate compensation for the systematic risk as wholesale energy costs rise or fall.⁷⁰

We consider that a hybrid approach of fixed dollar and percentage-based margins could be appropriate under the DMO reforms. It may provide some certainty to retailers by fixing a proportion of the margin in dollar terms that would not change as the DMO cost stack changes from determination to determination with increasing and decreasing cost components, while also allowing a separate proportion of the margin to respond to changes

⁶⁶ OTTER, [2025 Regulated Retail Electricity Pricing Investigation - Final Report](#), Office of the Tasmanian Economic Regulator, May 2025, pp. 48–49.

⁶⁷ OTTER, [2025 Regulated Retail Electricity Pricing Investigation - Final Report](#), Office of the Tasmanian Economic Regulator, May 2025, p. 56.

⁶⁸ ICRC, [Retail electricity price investigation 2024-27](#), Independent Competition and Regulatory Commission, 23 May 2024, pp. 47–48.

⁶⁹ OTTER, [2025 Regulated Retail Electricity Pricing Investigation - Final Report](#), Office of the Tasmanian Economic Regulator, May 2025, p. 55.

⁷⁰ Frontier Economics, [Retail electricity price investigation 2024-27](#), 23 November 2023, pp. 63–64.

in cost components. However, this approach is more complex than a fixed percentage margin.

Question 18: Based on DCCEE's proposed reforms, what other alternative approaches should we consider in quantifying the retail margin?

Question 19: Would a lower small business margin be more appropriate under the proposed reforms? If so, why?

Question 20: How should the retail margin be apportioned across the fixed and variable cost components of the DMO?

8.1.3 Reasonable retail margins under current Regulations

If the proposed Regulations are not adopted in time for DMO 8, we must have regard to the principle that electricity retailers should be able to make a reasonable profit.

In DMO 7, we decided to maintain the retail margins as a percentage of the DMO price (excluding the competition allowance), with margins of 6% for residential customers and 11% for small business customers. These represented the retail margins set in the DMO 6 determination.

Like in DMOs 6 and 7, we will continue to set the retail margin as a percentage instead of a fixed dollar amount because risks retailers face tend to scale with underlying costs. We will have regard to the information set out in section 8.1.1 to assess whether the 6% and 11% margins remain appropriate under a reasonable margin approach.

Question 21: What, if any, alternative methodologies should we consider in reassessing these retail margins?

8.2 Competition allowance

The proposed reforms to the Regulations include that when determining a DMO based on the efficient costs of supplying small customers on standing offers, the AER must not include an allowance for competition.

However, if the proposed Regulations are not adopted, and the current competition objective remains in effect, the AER would need to consider whether to include or exclude a competition allowance and how it should be quantified.

8.2.1 Including or excluding the competition allowance

The DMO 7 final determination gave greater weight to the price protection objectives of the DMO over the inclusion of the competition allowance. This was due to DMO 7 applying

during a period of sustained high inflation and heightened cost-of-living pressures. These matters are relevant considerations under s16(4)(d) of the Regulations.⁷¹

In determining whether to include the competition allowance, we have regard to the 12-month movements in trimmed mean CPI, reported on a quarterly basis by the Australian Bureau of Statistics. If the quarterly trimmed mean CPI exceeds the Reserve Bank of Australia's target band (of 2% to 3%) on a material and sustained basis, we will not include the competition allowance in the DMO prices to prioritise consumer protection.⁷² We think that, under the current Regulations, this decision framework is still appropriate for determining whether to include or exclude the competition allowance.

We consider that trimmed mean CPI is the more appropriate measure to gauge cost-of-living pressures. It minimises distortions by removing the more volatile items from the calculation of CPI, including those that both temporarily increase or decrease headline CPI.⁷³

On 23 July 2025 the Australian Bureau of Statistics announced that the first release of the complete Monthly CPI will be published on 26 November 2025. This publication will mark the transition from the quarterly CPI to the Monthly CPI as Australia's primary measure of inflation.⁷⁴ We intend to consider the monthly trimmed mean CPI series for DMO 8.

8.2.2 Quantifying the competition allowance

In DMO 7, we quantified the competition allowance by using the retailer costs to serve data, obtained by the AER through formal information requests, and then considered the spread of individual retailer costs to serve.⁷⁵

We consider this methodology would remain appropriate for DMO 8, if applicable, and are not proposing any further refinements.

⁷¹ Under the recommended amendments to the Regulations, this provision remains, as in 'any other matters the AER considers relevant.'

⁷² AER, [DMO 7 final determination](#), Australian Energy Regulator, 26 May 2025, p. 2.

⁷³ AER, [DMO 7 final determination](#), Australian Energy Regulator, 26 May 2025, p. 83.

⁷⁴ ABS, [Complete monthly measure of the CPI](#), Australian Bureau of Statistics.

⁷⁵ In DMO 7, these information requests were sent to 26 retailers, accounting for approximately 99% market share of residential and small business markets.

9 Annual usage and timing or pattern of supply

Under Part 3 of the Regulations, we are required to determine ‘broadly representative’ annual supply amounts for residential and small business customers within each DMO region, from which an annual price as reference price can be calculated. The outcomes paper does not recommend changing the role of the AER to determine ‘broadly representative’ usage amounts.

Throughout this document we refer to annual supply as annual usage. In addition to the annual usage, we must also determine the timing and pattern of supply to residential customers. These factors determine the ‘model annual usage’ consistent with the current Regulations and proposed reforms.

9.1 Annual usage amounts

In our DMO 7 final determination we retained the same usage amounts as previous determinations for residential customers and small business customers for general and controlled load usage. This consistency has provided continuity for stakeholders across multiple DMO years.

The ACCC’s July 2025 *Inquiry into the National Electricity Market report* indicates the annual usage amounts remain broadly representative for residential and small business customers.⁷⁶

For residential customers, the annual usage amounts assumed in the previous DMO determination were:

- within the interquartile range observed by the ACCC
- approximate to the medians observed by the ACCC
- for residential customers without controlled load, within 18% below to 9% above the medians observed by the ACCC
- for residential customers with controlled load, within 13% below to 13% above the ACCC medians observed by the ACCC.

For small business customers, the ACCC continue to observe a much wider range of usage, reflecting the variety of small businesses and the different ways they use electricity to produce goods and services.⁷⁷ The 10,000 kWh small business usage amount assumed in the DMO sits above the median but within the interquartile range.

There are several ways to adjust the annual usage amounts, such as setting amounts for each DMO region. Due to issues relating to year-on-year comparability with prior DMOs set

⁷⁶ ACCC, [Inquiry into the National Electricity Market report – July 2025 | ACCC](#), Australian Competition and Consumer Commission, Appendix E.

⁷⁷ ACCC, [Inquiry into the National Electricity Market report – July 2025 | ACCC](#), Australian Competition and Consumer Commission.

under the same regulatory framework and the complexity that brings with limited benefits, we propose to maintain the same annual usage amounts for DMO 8. However, if we observe large changes in annual usage amounts in the latest data, this could support the case for changing the annual usage amounts.

The outcomes paper does not recommend changing the role of the AER to determine ‘broadly representative’ usage amounts. Overall, we consider the current usage amounts meet the requirement of being broadly representative and we are not anticipating any more changes.

9.2 Timing or pattern of supply

The timing or pattern of supply we determine is used to convert time-of-use offers into annual prices. This allows for:

- time-of-use standing offers to be assessed for compliance with the annual DMO price
- time-of-use market offers to be compared with the DMO reference price in retailer price communications.

Determining the time-of-use pattern is a different role to determining a load profile to forecast wholesale prices discussed in chapter 5 and uses a different set of consumption data.

In our DMO 7 final determination we decided to retain our approach to timing and pattern of supply used since DMO 3 and maintained usage profiles sourced from AEMO interval meter data.

We have engaged further with AEMO since DMO 7 to isolate and remove identified controlled load consumption. We intend to otherwise retain the approach from previous determinations including to:

- assume the same usage occurs every day (with no variation for weekday or weekend)
- use the same proportional allocations of annual controlled load usage across multiple controlled loads
- retain a single 24-hour usage profile to describe the pattern of usage
- update the 24-hour usage profile using the AEMO interval meter data for each region, averaged over 4 years
- specify usage at 30-minute intervals.

Appendix A – List of stakeholder questions

Overall changes to the DMO

Question 1: How should the AER apportion costs across the supply and usage charge elements of the tariff? Is the proposed apportionment of cost elements appropriate?

Question 2: How should the AER determine maximum annual bill amounts? Should they be based on the flat DMO tariffs?

Network costs

Question 3: Under the proposed Regulations, should the separate flat rate and time-of-use DMO tariffs use the corresponding network tariff to determine network costs? Why or why not? What alternative approaches should be considered?

Question 4: Should the AER develop a blended network cost for the maximum annual bill, or should it instead adopt a particular network tariff? Why or why not? What alternative approaches should be considered?

Question 5: Under the current Regulations, should the AER continue to use the flat rate network tariff or instead develop a blended network tariff to derive network costs?

Question 6: If we were to create a blended cost, how could the issues for small business network tariffs be overcome?

Question 7: Where the corresponding network tariffs are used, and there is more than one default network tariff (for instance in Essential Energy and SA Power Networks), what approach should be used?

Wholesale costs

Question 8: Which option do you consider best meets the criteria set out above?

Question 9: What are your views on the application of the new approach to the Energex controlled load profile, in addition to the regions where AEMO's Controlled Load Profile is no longer published?

Question 10: What are the implications of adopting the 50th percentile WEC estimate instead of the 75th percentile, based on the back-cast analysis?

Question 11: What factors should we consider in determining whether a volatility allowance is necessary?

Question 12: Do you agree that the 50th percentile WEC estimate aligns more closely with the proposed requirement to consider the efficient costs to supply small customers?

Question 13: What parameters should we consider when deciding whether to include new products in the hedging strategy?

Question 14: Do you agree with the proposed approach to estimating time-of-use WECs? Is there an alternative approach we should consider?

Retail and other costs

Question 15: How can we best define and calculate the efficient costs to serve for small customers on standing offers?

Question 16: How can we best define and calculate a modest cost to acquire and retain customers?

Question 17: What is the appropriate split of bad debt across fixed and variable components that best reflects the propensity for bad debt to arise?

Retail margin

Question 18: Based on DCCEE's proposed reforms, what other alternative approaches should we consider in quantifying the retail margin?

Question 19: Would a lower small business margin be more appropriate under the proposed reforms? If so, why?

Question 20: How should the retail margin be apportioned across the fixed and variable cost components of the DMO?

Question 21: What, if any, alternative methodologies should we consider in reassessing these retail margins?