Australian Government

AUSTRALIAN ENERGY REGULATOR

2026–27 Default market offer

Draft determination

March 2026

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Invitation for submissions

Interested parties are invited to make submissions on this draft determination by close of business, 9 April 2026. We will consider all submissions received by this date in our final determination.

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

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Please ensure submissions are in PDF, Microsoft Word or another text readable document format.

We prefer that all views and comments be publicly available to facilitate an informed and transparent consultative process. Views and comments will be treated as public documents unless otherwise requested.

Parties wishing to submit confidential information should note their confidentiality claim in the email attaching the submission. Ensure it clearly identifies the information that is the subject of the confidentiality claim and provide a non-confidential version of the submission in a form suitable for publication.

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Key methodology concepts

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

Concept	Explanation
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 *Competition and Consumer Act 2010*.
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.
Annual usage	An annual electricity consumption amount considered broadly representative by the AER. This amount is applied to retailers' individual standing and market offers to determine whether standing offers are compliant with the DMO annual price.
Assumed customer load profile	Uses the pattern of supply as a foundation, with the option to modify based on assumptions about the behaviour of customers on the Solar Sharer Offer (SSO), such as to what extent customers will shift their usage into the 3-hour free usage period. The assumed customer load profile impacts our estimation of costs incurred by retailers to supply SSO customers and, therefore, impacts the final SSO tariffs.
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.
Comparison price	Referred to as the 'maximum annual bill' in the issues paper, this is 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 comparison price. This is a new requirement for the AER to determine as part of the recommended reforms.
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

Concept	Explanation
	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 DMOs 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 basis	The DMO tariff adopted to estimate costs incurred by retailers to supply SSO customers. This is different to the SSO tariff structure, which is the customer-facing tariff.
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.
Costs to serve	The group of costs electricity retailers incur as part of serving their customers, such as billing and call centres.
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.
Issues paper	The paper published by the AER on 5 November 2025 seeking input from stakeholders on the AER's approach to DMO 8.
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.
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).
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 could change prices more frequently under a market offer plan but may offer lower tariffs or other beneficial terms and conditions that appeal to customers.
Net System Load Profile	Data that contains aggregated electricity consumption of all customers with accumulation meters (or legacy meters) only.
Non-regulated tariff	Under the new Regulations, the AER sets certain regulated tariffs. It also provides an annual comparison price for any other tariffs or retail offers. These are referred to as non-regulated tariffs.

Concept	Explanation
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.
Pattern of supply	Different levels of electricity used by residential and small business customers throughout the day. The varying levels of demand form the pattern of supply.
Percentile estimate	The selected modelled wholesale cost estimate from the distribution of more than 600 modelled wholesale energy costs produced by our wholesale consultant, based on various combinations of weather, baseload availability, renewable generation and demand.
Reasonable use cap	A daily cap set by the Australian Government that applies to electricity usage in the 3-hour free usage period. Any electricity usage up to the reasonable use cap will be free, and any electricity usage above the cap will be charged at the excessive usage charge rate. The government has set the cap at 24 kilowatt hours.
Reasonable use tariff cap	The usage charge that applies to any electricity usage above the reasonable use cap in the 3-hour free usage period.
Regulated tariff	This refers to the types of tariffs listed in the Regulations for which the AER determines both a comparison price and a tariff cap. These are flat rate and flexible tariffs for both residential and small business customers, and controlled load tariffs and Solar Sharer Offer tariffs for residential customers.
Retail cost data	Retail cost data obtained from a cohort of 24 retailers that sell electricity to over 1,000 small customers across all DMO regions.
Retail margin	Included in the DMO price. A return to retailers reflecting the risk of selling electricity.
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.
Smart meter	Also referred to as an 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.
SSO exemption threshold	Retailers with fewer than 1,000 residential customers across all DMO regions are exempt from the requirement to offer the SSO to customers.
SSO outcomes paper	The paper published by the Australian Government on 23 January 2026 summarising feedback received on the government's consultation on the SSO in November 2025.

Concept	Explanation
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.
Tariff	From DMO 8 onward, the AER is 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).
Tariff cap	The AER is required to set the maximum amount of any fixed and/or variable charges that a retailer may charge small customers on regulated tariffs.
3-hour free usage period	3 consecutive hours in the middle of each day when electricity usage is free under the SSO.

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian 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
SSO	Solar Sharer Offer
VDO	Victorian Default Offer
WEC	Wholesale energy cost

1 Executive summary

This is our draft determination for retail electricity default market offer (DMO) prices to apply from 1 July 2026 to 30 June 2027.

These reforms set a new objective for the DMO to provide a fair, trusted and reasonably priced electricity option that reflects the costs of supplying small customers with an essential service. The regulatory framework also contains new mandatory considerations the AER must have regard to when determining DMO prices each year:

- efficient costs of supplying electricity in the distribution region to small customers on standing offers
- the types of small customers on standing offers to whom electricity is supplied in the distribution region
- modest costs to acquire and retain customers
- the long-term interests of consumers.

The reforms require the AER to produce DMO tariffs (flat rate and time of use), as well as annualised comparison prices, for residential and small business consumers.

Solar Sharer Offer

The amended Competition and Consumer (Industry Code – Electricity Retail) Amendment Regulations 2026 (the Regulations) also include the Solar Sharer Offer (SSO) as a new regulated electricity offer under the DMO framework. The SSO is an opt-in electricity offer that includes 3 hours of free power (up to a reasonable usage cap) during the day to take advantage of Australia's abundant solar energy resources. The SSO may suit customers with a smart meter who can shift some of their energy usage into the designated free power period.

This draft determination sets out the first SSO tariffs, which will be offered by most retailers to all residential customers in DMO regions who have a smart meter from 1 July 2026.[1]

2026–27 DMO draft determination price outcomes

Draft DMO 8 prices and tariffs are set out in our draft Legislative Instrument (Appendix C). Chapter 2 sets out annual prices based on flat rate and time of use DMO tariffs, and how these have changed from DMO 7.

Overall, flat rate DMO prices have decreased for all residential customers by 1.3% to 10.1%, and small business customers by 8.5% to 21.2% across all regions.

In NSW, compared with DMO 7, draft determination prices are between 2.7% and 8.2% lower for residential customers and between 8.5% and 21.2% lower for small business customers.

1 Electricity retailers supplying more than 1,000 residential customers across all DMO regions will be required to offer the SSO. Regulations, s. 11(3).

In SE Queensland, compared with DMO 7, draft determination prices are 10.1% lower for residential customers and 12.8% lower for small business customers.

In South Australia, compared with DMO 7, draft determination prices are 1.3% lower for residential customers and 15.2% lower for small business customers.

All year-on-year changes presented in this draft determination are nominal unless stated otherwise.

1.1 Our approach to DMO 8

For each DMO determination, we consider wholesale, network, environmental and retail operating costs, along with a retail margin. Under the new Regulations we still have regard to these individual cost components, but we have adjusted some aspects of the methodology to reflect the new DMO objective and mandatory considerations.

For DMO 8, we consulted on aspects of the DMO methodology via an issues paper published in November 2025. This covered elements affected by the regulatory reforms as well as issues arising from changing market conditions.

The exception to this was the SSO, for which the Australian Government was still developing policy settings. To inform our draft determination for the SSO, we considered the submissions made to the government's own consultation and focused on feedback regarding design elements relevant to the AER's role. Following the release of the government's SSO outcomes paper in early 2026, we undertook a targeted consultation with a sample group of impacted stakeholders – including retailers, distribution network service providers (DNSPs) and consumer groups – on the SSO design principles outlined in that paper. Given the tight timelines, this approach enabled us to develop an informed SSO draft decision and a solid basis for broader consultation through this draft determination. We invite comments on our approach in response to this draft decision.

We summarise our approach to the DMO methodology for each cost stack element of the DMO 8 draft determination below.

1.1.1 Wholesale cost methodology

The key adjustment we have made to the wholesale methodology is in how we select the forecast wholesale energy cost (WEC) from the large array of potential cost outcomes produced through modelling. These outcomes vary because the model is examining how wholesale spot market prices may fare depending on weather and generator availability and then testing the performance of retailer risk management contracts against these outcomes. For our draft DMO 8 determination, we have adopted the 50th percentile WEC estimate and included a volatility allowance. This decision is based on our examination of past wholesale modelling outcomes relative to market performance and on the reforms to the DMO framework. We consider the 50th percentile is best aligned with the requirement to consider efficient costs, while a volatility allowance will compensate retailers for the cost to hold capital to manage WEC forecast risk. This reduces the WEC estimate to an efficient level, ensuring consumers pay a price closer to efficient costs, while still ensuring that retailers can sufficiently manage cases where their wholesale costs differ from our forecasts.

We have used interval meter data only as our basis for forecasting controlled load demand, in all regions. This reflects the improved accuracy of this dataset compared with the historic controlled load profile based on a sample of accumulation meters, which has now also been discontinued in some regions. The change also ensures future amendments to the methodology will not be required as the transition to smart meters for all customers across the National Electricity Market (NEM) continues. Based on this decision, we have also removed the interval meter controlled load data from the general energy consumption load profiles.

1.1.2 Network costs

The draft DMO prices and tariff caps reflect the underlying network tariffs that retailers are charged, or can select.

For flat rate tariff caps and comparison prices, either a flat rate or time of use network tariff can apply. To create the DMO prices, we have selected the network tariff resulting in the lowest tariff caps and comparison prices, which are:

- in Ausgrid and Endeavour Energy regions, the lower flat rate network tariff
- in Essential Energy, Energex and SA Power Networks regions, the time of use network tariff.

For time of use tariff caps and comparison prices, we have applied the applicable default time of use network tariff in all regions, except for Ausgrid where the most common time of use network tariff will apply. Ausgrid's default time of use network tariff is a demand tariff and under the Regulations a time of use DMO retail tariff cannot include demand charges.

We consider this approach is consistent with the mandatory consideration of allowing retailers to recover the efficient costs to supply customers on standing offers.

1.1.3 Environmental costs

We are continuing our existing market-based approach to environmental cost forecasting.

1.1.4 Retail costs

We have maintained our approach of applying a customer-weighted average (once statistical outliers are excluded) to all retailers' reported costs to establish an efficient benchmark for costs to serve and other retail costs. This approach aligns with the Essential Services Commission of Victoria's (ESC) approach in setting efficient retailer costs.

As this benchmark reflects the revealed costs of most retailers operating in competitive markets, we consider it provides appropriate incentives for retailers to operate efficiently and meet this benchmark over time. Similarly, our approach to quantifying smart meter cost allowances remains the same as in previous DMO determinations.

We have applied the standing offer customer-weighted average approach to determine the costs to acquire and retain customers. This is lower than the overall customer-weighted average and aligns with the new requirements to set these particular costs at a modest level.

We have applied a customer-weighted average of actual written-off bad debt expenses reported by retailers. This represents a change from previous DMO determinations, which used costs associated with provisioning for bad and doubtful debt. We consider that using written-off bad debt protects consumers from over-recovery of bad debt and prevents the under-recovery of bad debt by retailers.

We are consulting on whether bad debt should be allocated as a fixed or variable charge component of the DMO price that scales with electricity consumption. This is further discussed in chapter 7.

1.1.5 Retail margins

We have applied uniform retail margins of 6% across both residential and small business customers. Where risks of supplying electricity to small businesses are greater than that for residential customers, this is now already accounted for in other DMO components due to other changes we have made. We found that small businesses also exhibit lower compliance risks, churn and price sensitive risks relative to residential customers. We also observe that competition did not diminish in the Victorian small business segment when applying uniform margins. We consider that, with these factors combined, it does not justify a higher small business margin relative to residential customers under an efficient pricing framework.

1.1.6 Overall changes to the DMO

In our new role of setting DMO tariff caps, we have decided to pass through fixed and variable costs into the different tariff components (daily supply and usage charges) because these costs would be incurred by a retailer. As shown in chapter 9, this has led to a number of tariff caps with higher daily supply charges than what is currently observed in the market. While overall prices are decreasing, we are conscious that these higher charges may cause bill impacts to standing offer customers with low usage, due to the fixed nature of daily supply charges. We are also aware this may have flow-on impacts on retailers' market offers, depending on their response to DMO 8.

We have adopted this position in the draft determination as it is cost reflective and transparent. It also aligns with stakeholder feedback, which supported simplicity in the methodology. However, noting the higher daily supply charges, we are seeking stakeholder feedback on 3 options that could shift the recovery of costs from the daily supply charge into usage charges, which is explained further in section 9.3.3.

We have also determined that the annual price for time of use tariffs will also serve as the comparison price for non-regulated tariffs.

1.1.7 Solar Sharer Offer

We have designed the first SSO tariffs in accordance with the Regulations and guidance provided by the government in the SSO outcomes paper.[2] This includes prioritising practicality for the initial implementation of the SSO.

To determine the optimal timing of the free usage period in each DMO region, we considered periods of high solar generation (both rooftop and large-scale), low wholesale prices, low network costs and low demand. This has resulted in setting of free usage periods of 11 am to 2 pm in NSW and South East Queensland (SE Queensland), and 12 pm to 3 pm in South Australia (in local time). The free usage periods are fixed in local time year-round and do not change for daylight savings, which is intended to prioritise practicality and support customer understanding.

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2 For more information, see the SSO design principles set by the Australian Government in the SSO outcomes paper.

To develop the SSO tariff structure, we overlaid the designated free usage periods onto the corresponding time of use DMO tariffs. This approach best reflects the varying costs to supply customers throughout the day and maintains pricing signals for customers to shift electricity use into the free usage period.

We have designed the SSO with the objective that a customer with electricity usage similar to our modelled estimates who shifts any electricity consumption into the free usage period should be better off than if they did not shift their consumption while on the standard time of use DMO. We estimated costs that retailers would incur in the free usage period and then reapportioned them to the non-free usage periods by the assumed volume of electricity consumed in each period. This results in the usage charges outside the free usage period being 1 to 4 cents per kilowatt hour (kWh) higher than the corresponding standard time of use DMO tariff, depending on the DMO region. We did not allocate any of the costs to the daily supply charge, so the daily supply charges are the same as the standard time of use DMO.

We have set the usage charge that is applied to any electricity usage in the free usage period above the 24 kWh reasonable use cap, at the corresponding off peak or solar soak SSO tariff rate.

1.2 Market drivers of draft DMO 8 tariffs and prices

DMO 8 tariffs and prices are impacted by changes to both the DMO methodology and underlying market conditions. Appendix F sets out these changes in each jurisdiction in detail. Overall methodology changes have impacted nearly all aspects of the DMO, including wholesale (percentile estimate), networks (adoption of most efficient tariff), retail (changes for modest customer acquisition and retention costs) and margin (alignment of small business with residential).

In terms of market drivers of costs, across all regions, wholesale, environmental and retail costs have decreased. Lower wholesale costs are a result of decreasing contract prices for the upcoming 2026–27 financial year. Contract price decreases reflect the lack of spot price volatility observed since June 2025, with the magnitude and frequency of high spot prices at the lowest level observed in several years. The lack of volatility is partly driven by higher output from wind and battery generators, which has reduced reliance on gas and hydro generation during evening demand peaks. South Australian wholesale costs decreased by less than other regions, due to a significant increase in ancillary service costs resulting from several high-priced events for Frequency Control Ancillary Services (FCAS) that occurred across July and August 2025.

We are monitoring the impact of the conflict in the Middle East on global fuel prices and note that any impacts on gas, coal and ASX contract prices will be considered and captured within the final determination. The wholesale energy costs used in this draft determination were produced prior to the outbreak of the conflict. Therefore, they do not reflect the increases in electricity contract prices that have occurred since the conflict began. To date, volume-weighted average contract prices for the DMO 8 period remain lower in all regions than in DMO 7, despite the recent conflict-driven price increases. We will continue to monitor this in the lead up to the final determination for DMO 8.

Overall, network tariff prices have increased since DMO 7 for all DMO DNSPs when compared on a like-for-like basis (that is, flat rate to flat rate, time of use to time of use etc.).

These increases reflect the price paths and approved expenditure set out in our respective revenue determinations. In all DMO regions, a key driver of the price paths was market factors (higher actual inflation than forecast and interest rates) causing a higher return on capital. Increases also reflect replacement expenditure by distribution networks and investment in new transmission capacity to support growth in renewable generation, as well as expenditure in important emerging areas such as improved network resilience to address climate change-related risks, the uptake and integration of consumer energy resources and cyber security.

However, these increases in network prices do not necessarily result in increases in the network costs included in the DMO prices and paid by customers. This is because, as described above, we can choose the network tariff that is most appropriate when calculating an efficient cost. This has led to a shift away from network tariffs used under previous DMOs, towards lower cost options.

In Essential Energy and Energex, this approach has resulted in network cost decreases of between 1.3% and 20.3%, depending on customer type and region.

In SA Power Networks, applying the lower cost time of use network tariff results in small business network cost decreases of 16.8% and residential cost increases by 3.8%.

In Ausgrid and Endeavour Energy, the network costs in the DMO have increased for residential and small business customers by 3.6% to 10.1%, depending on customer type and region. This is because both the flat rate and time of use network tariffs in these regions are higher than the flat rate network tariff used in DMO 7. This increase in network costs partly offset the reductions in other DMO cost components.

Environmental costs have significantly decreased due to lower Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) costs in all regions. These decreases in LRET costs are driven by large falls in large-scale generation certificate prices. Overall, environmental costs reductions have had a greater impact on DMO prices than reductions in retail costs, even though they are a smaller element of the cost stack.

Retail cost decreases are a result of lower reported costs from retailers. The latest 2024–25 cost data provided by retailers indicates reductions in key cost components, including the costs incurred to serve customers, the costs to acquire and retain customers, and other shared costs attributable to the electricity retailing division. The decrease is also driven by a methodological change, including applying the standing offer customer-weighted average to determine modest costs to acquire and retain customers, and using written-off bad debt rather than bad and doubtful debt, which includes provisions. These decreases are slightly offset by increases in smart meter costs, reflecting the greater uptake of smart meters since the 31 March 2025 smart meter uptake numbers used in the DMO 7 final determination.

Appendices E, F and G set out all of the year-on-year price changes, broken down by cost component and whether the change was driven by the methodology or underlying market drivers, for each region.

1.3 Request for stakeholder feedback

Engagement has played a large role in the DMO 8 draft determination. We have valued the significant input provided by all stakeholders, including retailers, consumer groups and distribution businesses, in the development of the draft determination.

The amended regulatory framework means the AER is making a large number of new determinations for DMO 8. We have highlighted aspects of these throughout this document, on which we welcome stakeholder views. These include:

- DMO tariffs and allocation of fixed and variable costs.
- The SSO – We are mindful not all stakeholders have had the opportunity to formally engage with the AER on the design of the SSO. Therefore, we welcome stakeholder views on the proposed SSO tariffs, including the:
  - timing of the free usage periods and any implementation and communication implications from the approach to set free usage periods in local time
  - SSO tariff structure
  - approach to estimating costs incurred by retailers during the free usage periods and how they should be reapportioned across non-free usage periods.

1.4 Future work

Some aspects of the government's reforms to the DMO framework will not be implemented in DMO 8. The following aspects are anticipated to be implemented for DMO 9:

- **DMO guideline:** The Regulations require the AER to publish a DMO guideline before 1 December 2026. This guideline will set out our approach to determining the DMO, achieving the DMO objective and meeting the requirements of the Regulations. We intend to commence development of the guideline after the DMO 8 final determination.
- **Further developments to the SSO:** We have prioritised practicality in setting the first SSO tariffs. The AER will consider impacts of the SSO once implemented and may adjust our approach in DMO 9 based on consumer response, stakeholder feedback and lessons learned. The DMO guideline will also include our approach to designing the SSO and will be a further opportunity for stakeholders to provide views on our approach.
- **Extension of protections to embedded network customers:** The DMO outcomes paper envisages DMO protections being extended to small customers in embedded networks from DMO 9 onwards. We intend to consult on how to best determine the DMO tariffs and comparison prices for these customers as part of the DMO guideline.

The AER is not consulting on these matters as part of the DMO 8 draft determination consultation. We intend to engage with stakeholders on these issues through consultation on the DMO guideline after the DMO 8 final determination.

2 DMO 8 draft prices

Draft DMO prices for 2026−27 for each customer type in each distribution region are set out in Table 2.1 to Table 2.2. The tables show the changes from DMO 7 in both real terms (adjusted for forecast inflation) and nominal terms. The draft DMO prices are based on the most recent data available.

Table 2.1 DMO 2026−27 draft determination prices, residential customers, changes from DMO 7 (nominal and real terms)

Distribution regions	Description	Residential, flat rate	Residential, time of use	Solar Sharer Offer
Ausgrid	DMO price	$1,875	$1,886	$1,886
	For annual usage of	3,900 kWh	3,900 kWh	3,900 kWh
	Change y-o-y	-$90 (-4.6%)	-$79 (-4.0%)	–
	Change y-o-y (real)	-$173 (-8.8%)	-$162 (-8.2%)	–
Endeavour Energy	DMO price	$2,347	$2,353	$2,353
	For annual usage of	4,900 kWh	4,900 kWh	4,900 kWh
	Change y-o-y	-$64 (-2.7%)	-$58 (-2.4%)	–
	Change y-o-y (real)	-$165 (-6.9%)	-$159 (-6.6%)	–
Essential Energy	DMO price	$2,515	$2,515	$2,515
	For annual usage of	4,600 kWh	4,600 kWh	4,600 kWh
	Change y-o-y	-$226 (-8.2%)	-$226 (-8.2%)	–
	Change y-o-y (real)	-$341 (-12.4%)	-$341 (-12.4%)	–
Energex	DMO price	$1,927	$1,927	$1,927
	For annual usage of	4,600 kWh	4,600 kWh	4,600 kWh
	Change y-o-y	-$216 (-10.1%)	-$216 (-10.1%)	–
	Change y-o-y (real)	-$306 (-14.3%)	-$306 (-14.3%)	–
SA Power Networks	DMO price	$2,270	$2,270	$2,270
	For annual usage of	4,000 kWh	4,000 kWh	4,000 kWh
	Change y-o-y	-$31 (-1.3%)	-$31 (-1.3%)	–
	Change y-o-y (real)	-$128 (-5.5%)	-$128 (-5.5%)	–

Note: Real comparisons with DMO 7 are based on RBA 2025–26 inflation forecast of 4.2% in its February 2026 Statement on Monetary policy.

Table 2.2 DMO 2026−27 draft determination prices, small business customers, changes from DMO 7 (nominal and real terms)

Distribution regions	Description	Small business, flat rate		Small business, time of use	
Ausgrid	DMO Price	$4,474		$4,598	
	For annual usage of	10,000 kWh		10, 000 kWh	
	Change y-o-y	-$503	(-10.1%)	-$379	(-7.6%)
	Change y-o-y (real)	-$712	(-14.3%)	-$588	(-11.8%)
Endeavour Energy	DMO Price	$4,367		$4,396	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-$408	(-8.5%)	-$379	(-7.9%)
	Change y-o-y (real)	-$609	(-12.7%)	-$580	(-12.1%)
Essential Energy	DMO Price	$4,902		$4,902	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-$1,320	(-21.2%)	-$1,320	(-21.2%)
	Change y-o-y (real)	-$1,581	(-25.4%)	-$1,581	(-25.4%)
Energex	DMO Price	$3,744		$3,744	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-$550	(-12.8%)	-$550	(-12.8%)
	Change y-o-y (real)	-$730	(-17.0%)	-$730	(-17.0%)
SA Power Networks	DMO Price	$4,696		$4,696	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-$845	(-15.2%)	-$845	(-15.2%)
	Change y-o-y (real)	-$1,078	(-19.4%)	-$1,078	(-19.4%)

Note: Real comparisons with DMO 7 are based on RBA 2025–26 inflation forecast of 4.2% in its February 2026 Statement on Monetary policy.

Draft DMO tariff caps for 2026−27 for each customer type in each distribution region are set out in Figure 2.1 to Figure 2.6.

Figure 2.1 DMO 2026–27 draft determination residential flat rate DMO tariff caps

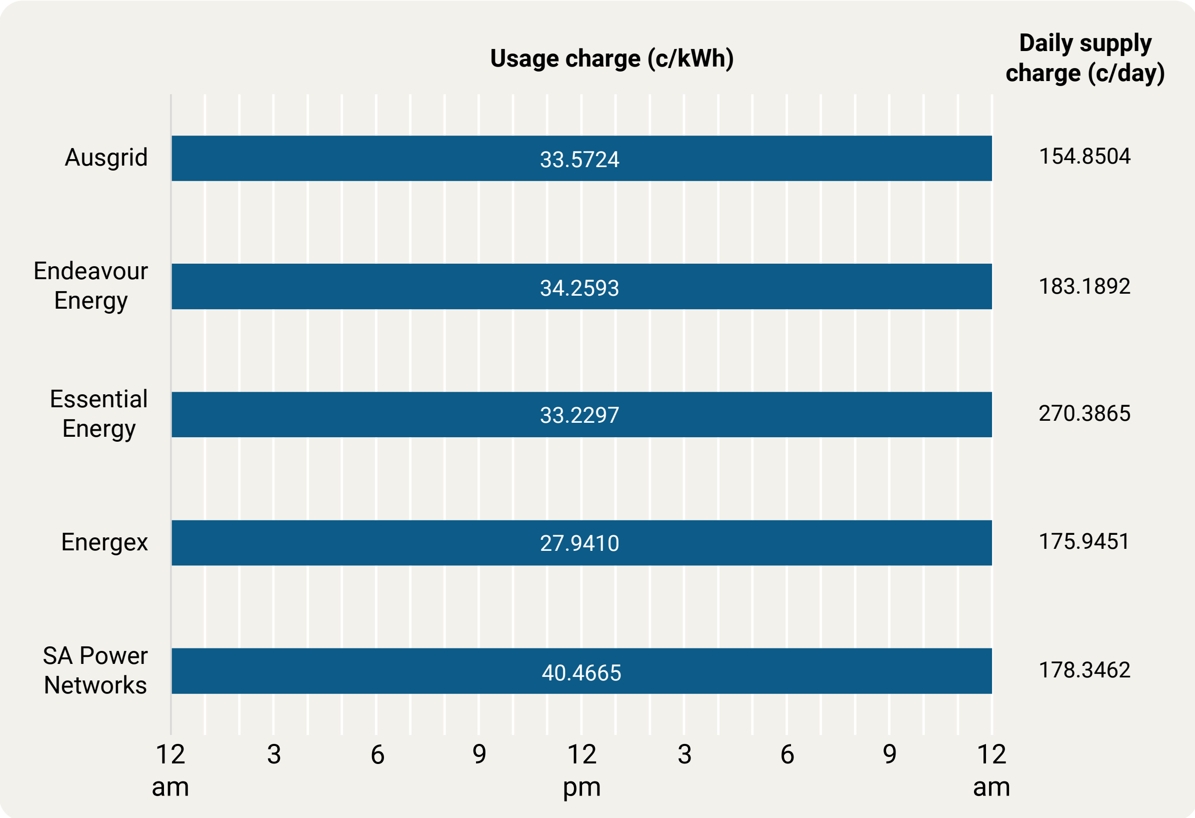
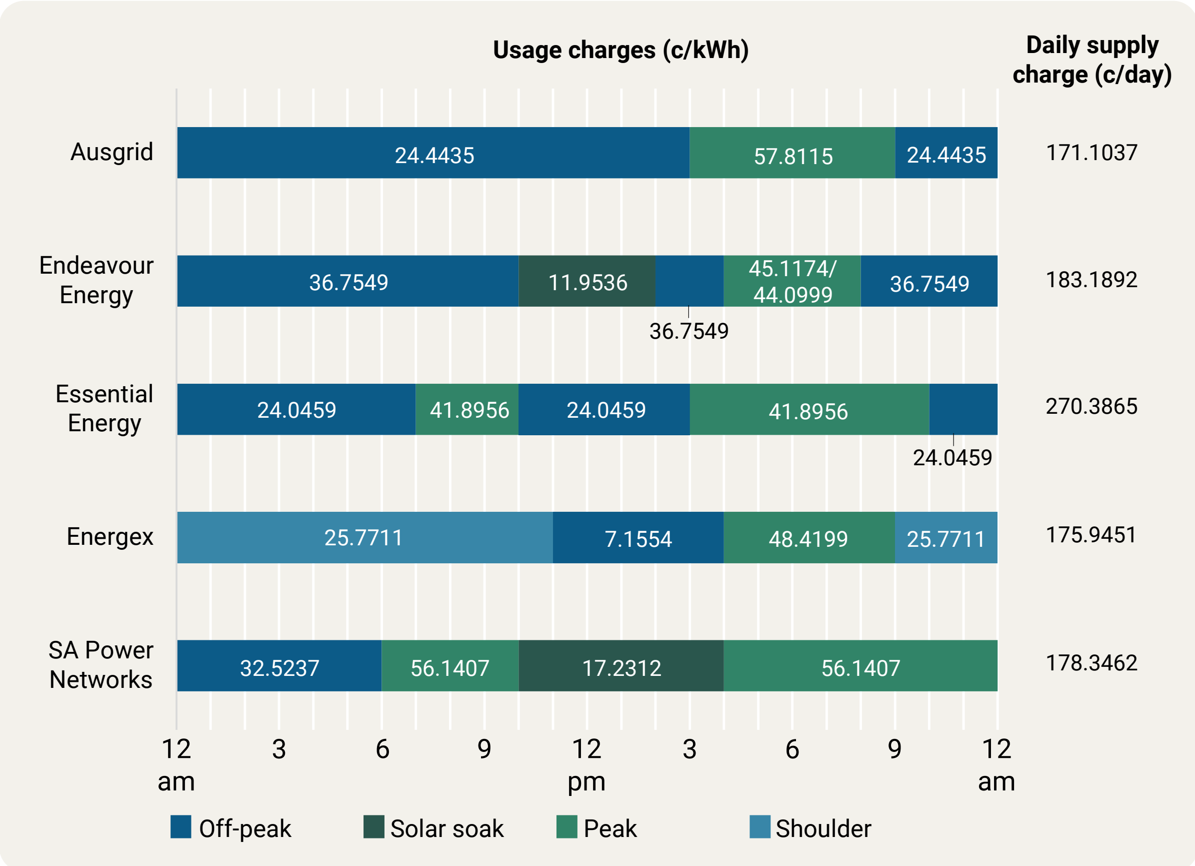
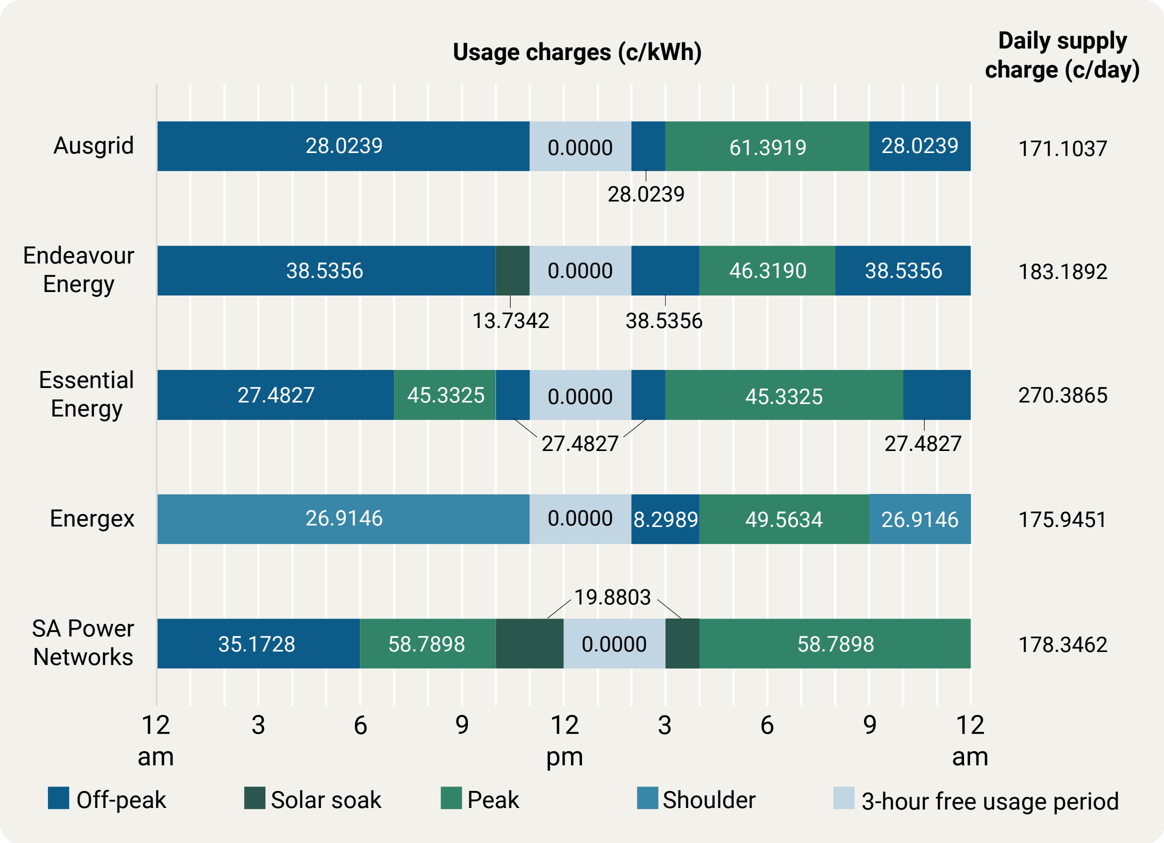


Figure 2.2 DMO 2026–27 draft determination residential time of use DMO tariff caps



Note: Specific details of usage charges across different time of use windows is set out in the legislative instrument (Appendix C).

Figure 2.3 DMO 2026–27 draft determination residential Solar Sharer Offer DMO tariff caps



Note: Specific details of usage charges across different time of use windows is set out in the legislative instrument (Appendix C). Any usage in the 3-hour free usage period above the reasonable use cap (24 kWh) will be charged at the reasonable use tariff cap, which is the respective off-peak charge in Ausgrid, Essential Energy and Energex, and the respective solar soak charge in Endeavour Energy and SA Power Networks.

Figure 2.4 DMO 2026–27 draft determination small business flat rate DMO tariff caps

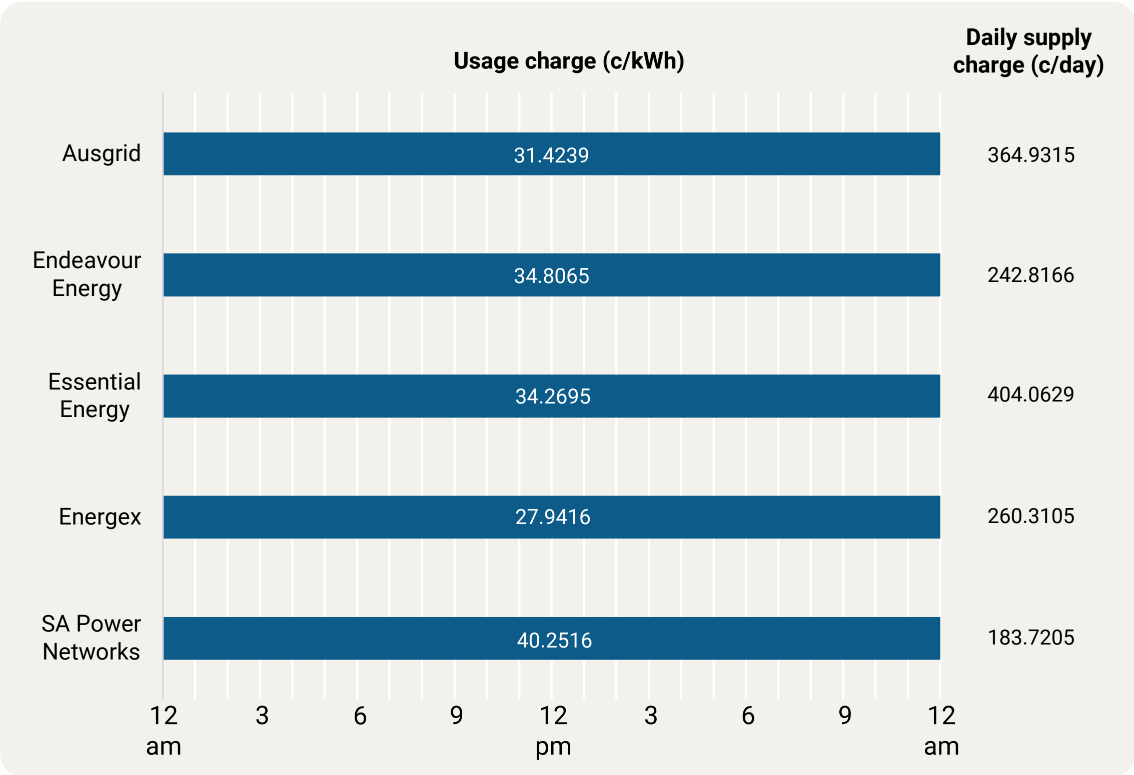
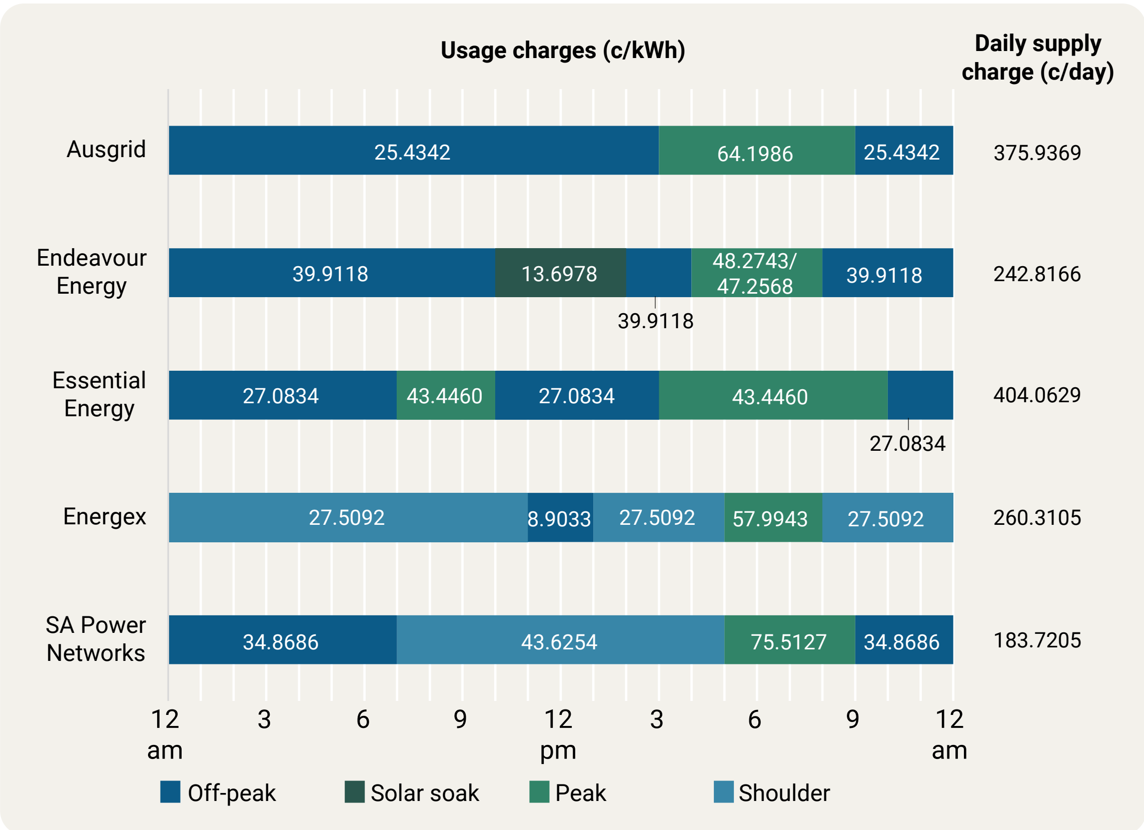


Figure 2.5 DMO 2026–27 draft determination small business time of use DMO tariff caps



Note: Specific details of usage charges across different time of use windows is set out in the legislative instrument (Appendix C).

Figure 2.6 shows the separate controlled load DMO tariff caps that can be included alongside other residential DMO tariff caps (flat rate, time of use and solar sharer).

Figure 2.6 DMO 2026–27 draft determination residential controlled load DMO tariff caps

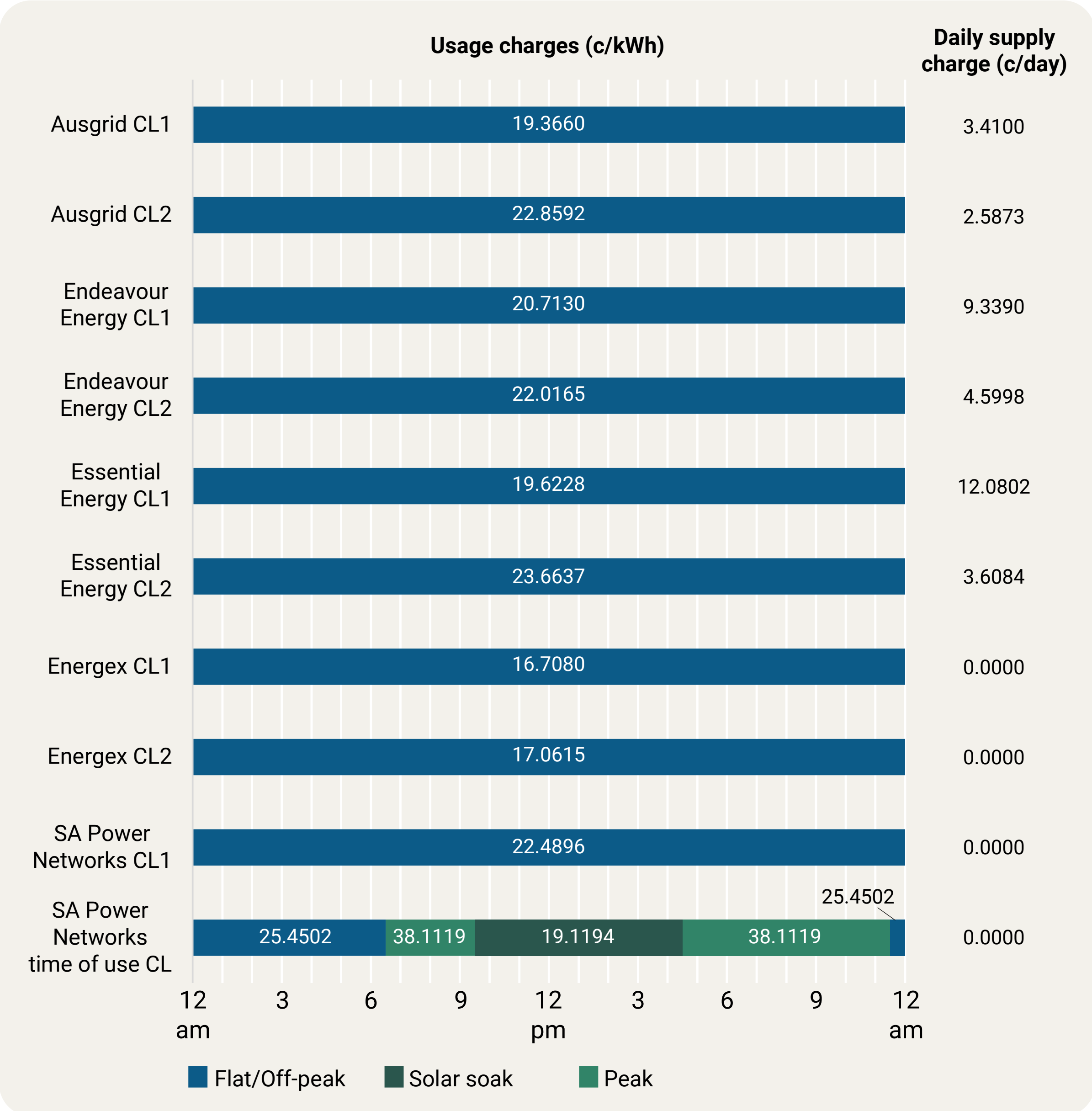
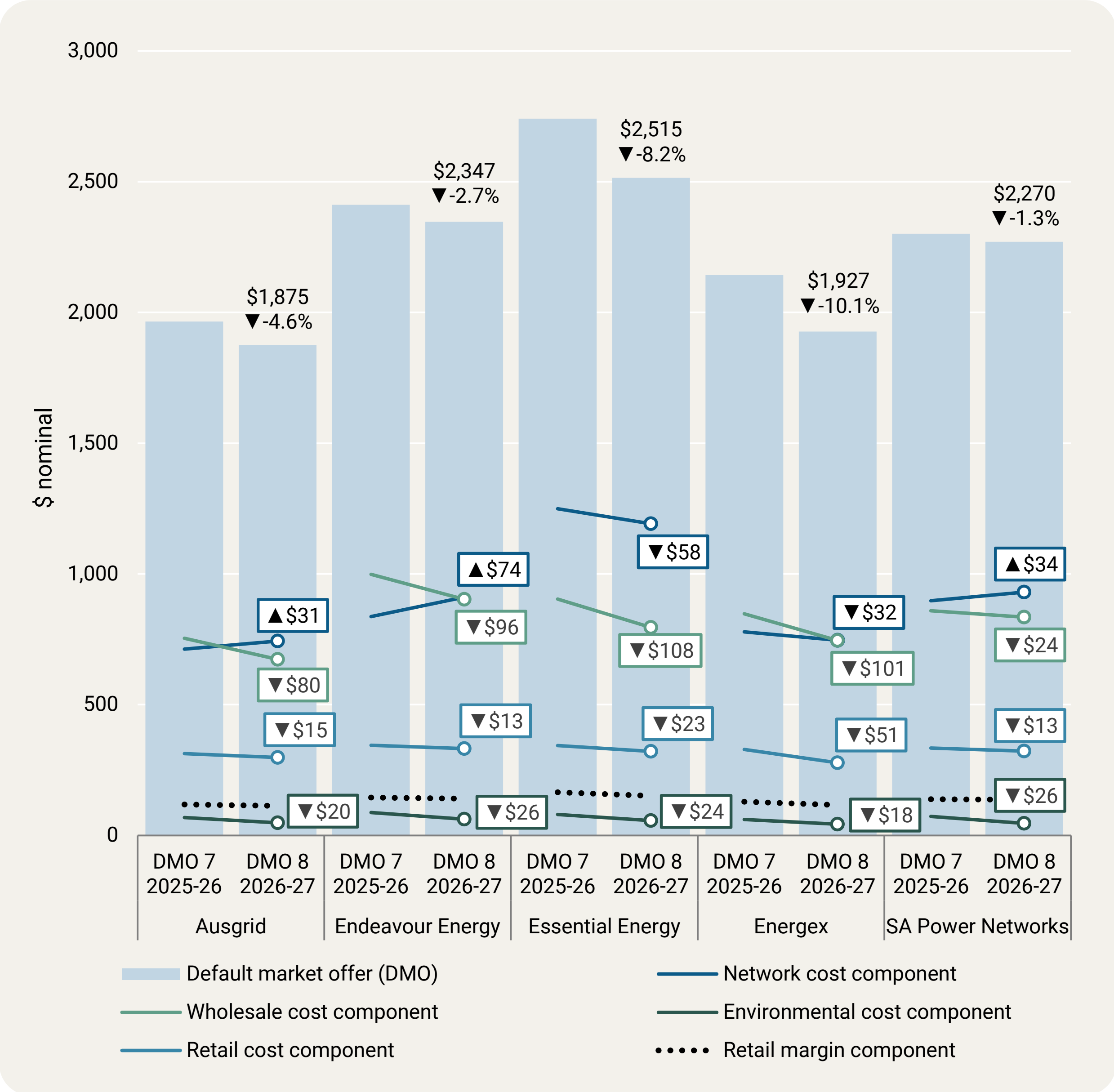


Figure 2.7 shows the movement in the key cost components since DMO 7. It illustrates that all key cost components, except for network costs, have decreased since DMO 7.

Figure 2.7 Composition of the default market offer (DMO 7 and DMO 8 (nominal terms))



Note: Prices displayed are for flat rate residential customers.

3 Role of the AER

As an independent regulator, the AER is responsible for enforcing the laws for the National Electricity Market (NEM) and spot gas markets in southern and eastern Australia. Across all our functions and objectives, we strive to promote the long-term interests of consumers.[3]

We report on the conduct of market participants and the effectiveness of competition, and we regulate electricity networks and covered gas pipelines in all jurisdictions except Western Australia. Our retail energy market functions cover New South Wales (NSW), South Australia, Tasmania, the Australian Capital Territory (ACT) and Queensland. In Victoria, we are responsible for overseeing the Retailer of Last Resort arrangements.[4]

Under the Competition and Consumer (Industry Code – Electricity Retail) Amendment Regulations 2026 (the Regulations), our role is to set DMO prices each year for non-price regulated network distribution regions – NSW (Endeavour Energy, Essential Energy and Ausgrid), South East Queensland (Energex) and South Australia (SA Power Networks).[5]

3.1 DMO regulatory framework

In 2025 the DMO framework was reviewed by the Australian Government, which resulted in amendments to the Regulations and changes to the way the AER is required to set the DMO.[6]

The main changes are:

- the introduction of a new statutory objective focused on protecting small customers on standing offers
- a requirement for the AER to determine both DMO annual prices and tariff caps based on the efficient costs of supplying those customers, with reference to mandatory considerations and a new DMO guideline to be developed by the AER before DMO 9
- a requirement for the AER to determine tariff caps for common standing offer types, as well as a new SSO tariff, set comparison prices for these regulated tariff types and a comparison price based on a model annual usage for non-regulated tariffs.

3.1.1 Previous DMO determinations

The previous Regulations have applied since the DMO came into effect in 2019. Under these, the AER was required to determine the DMO as a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of a type in a region. We had to have regard to a range of specific matters and costs, including

3 AER, AER Strategic Plan 2020–25, Australian Energy Regulator, 14 December 2020. New plan to be implemented once legal separation from the ACCC takes place on 1 July 2026.

4 The AER became responsible for the Retailer of Last Resort arrangements in Victoria on 30 July 2024 with the commencement of the National Energy Retail Law (Victoria) Act 2024.

5 Regulations, s. 15(1).

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

retailers' costs, a reasonable profit principle, costs to acquire and retain customers, network and wholesale costs, compliance costs and any other matter the AER considered relevant.[7]

This approach was guided by policy objectives as set out in Figure 3.1.[8] DMO 7 is the last determination made under these policy objectives.

Figure 3.1 Previous DMO policy objectives

3.1.2 Amended DMO Regulations[9]

On 5 March 2026, the Competition and Consumer (Industry Code—Electricity Retail) Amendment Regulations 2026 (the Regulations) was enacted and applies from DMO 8. Pursuant to section 4(2) of the *Act Interpretation Act 1901* (Cth), the AER will exercise its powers under the Regulations as if the relevant commencement had occurred for determining DMO 8. For ease of reference, we will refer to the current Regulations, which will be superseded on 1 July 2026, as the 'old Regulations' and the amended Regulations, under which the AER will make its draft and final DMO 8 determination, as the Regulations.

The amendments to the Regulations include a new objective[10] and mandatory considerations as set out in Figure 3.2.[11]

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7 See the old Regulations s. 16(4).

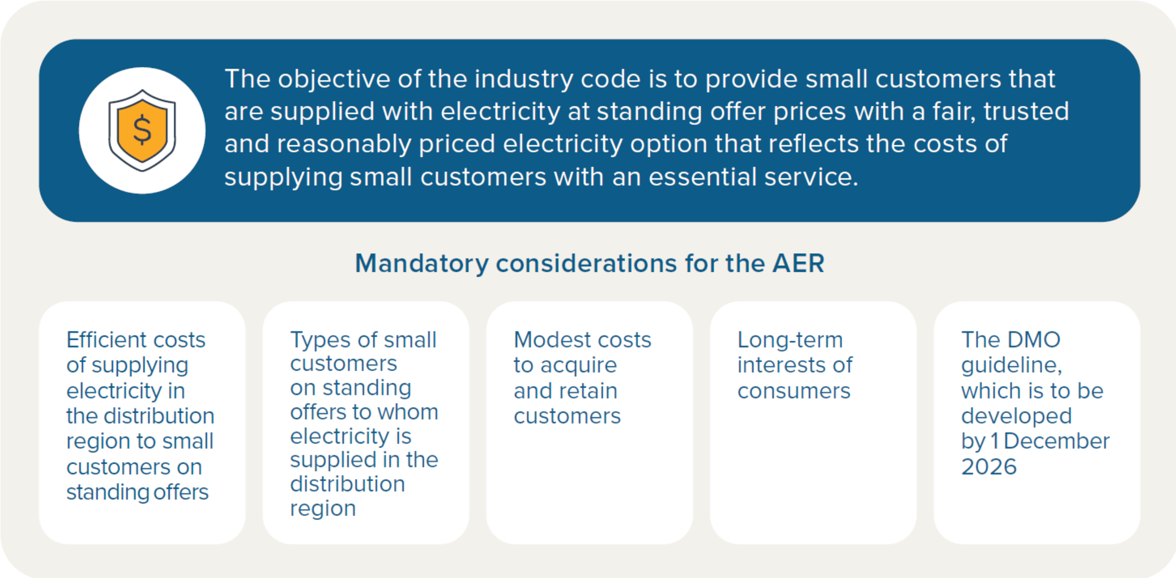
8 When the DMO Regulations were introduced, the government of the time also provided policy objectives to be found in: the ACCC Retail Electricity Pricing Inquiry final report, June 2018; the Explanatory Statement accompanying the DMO Regulations, 2019; Treasurer's and Minister for Energy's request to the AER to develop a DMO, 22 October 2018; and the Minister for Climate Change and Energy's letter, 2023.

9 For the full suite of amendments see the Competition and Consumer (Industry Code – Electricity Retail) Amendment Regulations (2026). Unless otherwise stated all references will be to these amendments as they modify the Competition and Consumer (Industry Code – Electricity Retail) Regulations (2019).

10 Regulations, s. 9A(1).

11 Regulations, ss. 16(4)(a), (b), (ba), (c)(iv), (ca), and (cb).

Figure 3.2 DMO objective and new mandatory considerations



The following matters that the AER has previously had to have regard to remain unchanged:

- the wholesale cost of electricity in the region
- the cost of distributing and transmitting electricity in the region
- the cost of complying with the laws of the Commonwealth and the relevant state or territory to supply electricity in the region
- any other matters the AER considers relevant.[12]

The amendments have removed the reasonable profit principle[13] and any competition allowance.[14] However, the Explanatory Statement to the Regulation amendments and the DMO outcomes paper make clear that the requirement to consider the efficient costs to supply standing offer customers is inclusive of retail margins.[15] Chapter 8 covers this in detail.

3.2 DMO objective and mandatory considerations

The AER will be guided by the DMO objective and the mandatory considerations in determining the DMO. The concepts in the objective, 'fair, trusted and reasonably priced', have implications for how the AER determines the DMO each year.

3.2.1 Stakeholder feedback

The DMO 8 issues paper consulted on the wider implications of the regulatory changes to the DMO framework.

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12 Regulations, ss. 16(4)(c)(i)–(iii) & (d).

13 Old Regulations, s. 16(4)(b).

14 Explanatory Statement, p. 2, and DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 6.

15 Explanatory Statement, item 41, and DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 6.

- Fair – The retailer workshops brought forth an interpretation of fairness that included consideration of businesses operating in the market, and not just Tier 1 retailers.[16] Submissions from retailers also reflected that a 'fair' DMO is one where business conditions are stable, predictable and viable.[17] We heard from consumer groups that fairness means ensuring consumers, especially vulnerable consumers, are protected by the DMO. Energy Consumers Australia (ECA) suggested a 'fair' price is one that only includes efficient costs to supply electricity[18] and the Justice and Equity Centre (JEC) advocated using equity in outcomes as a touchstone for fairness.[19] Both the ECA and the South Australian Department for Energy and Mining mentioned cost-of-living pressures as relevant to consideration of what is a fair and affordable DMO price.[20]
- Trusted – Consumer groups associated trust with the status of the DMO itself as being trusted by consumers, evidence-based and well communicated.[21] The JEC commented that consumers mistrust the energy market and so the DMO should be an affordable price set for all consumers regardless of whether they can or do shop around.[22] ECA also mentioned confidence in the AER's protection of consumers.[23]
- Reasonable – When this term was mentioned by retailers, it was linked with 'fair' and 'efficient', suggesting the importance of competition and viability for retail businesses.[24] Further, it was contended that the way 'reasonable' was previously applied in the DMO was already close to efficient.[25] Consumer groups linked reasonable with affordability for all consumers, as well as with recovery of efficient costs for retailers.[26]
- Efficient costs – Specific feedback on this term will be covered in the cost stack chapters and as relevant to selected methodology and outcomes. However, in general:
  - Some retailers considered the DMO is already at an efficient price level.[27] Retailers in general upheld that efficiency as a measure should also accommodate the viability of retailers and the efficiencies created in a dynamic market.[28]
  - Consumer groups were generally of the view that the mandatory consideration of efficient costs opens up the whole DMO framework for revision and the centrality of consumer protection for each decision in the DMO determination.[29] There was also a general perspective from consumer groups that setting efficient costs motivates

16 For example, EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 2.

17 For example, AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 1–2.

18 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 3–4.

19 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 3.

20 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 3; South Australian Department for Energy and Mining, Submission to DMO 8 issues paper, 12 December 2025, p. 1.

21 Customer Consultative Group, Submission to DMO 8 issues paper, 19 November 2025, p. 4.

22 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 3.

23 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 4.

24 For example, AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 1.

25 For example, Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 1.

26 For example, Customer Consultative Group, Submission to DMO 8 issues paper, 19 November 2025, p. 4.

27 For example, Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 1.

28 For example, AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 1.

29 For example, SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, p. 7 and JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 2–3.

retailers to be efficient and that costs to serve that do not benefit, and cannot be shown to benefit, standing offer customers should not be included.[30]

- Types of customers on standing offers – Retailers said for their business operations there is no distinction in costs to serve between standing offer customers and market offer customers.[31] Consumer groups also pointed out this was a false distinction because anyone could be a standing offer customer at any time,[32] which means that when the AER has regard to the types of customers on standing offers it could mean looking at the characteristics of any energy user. However, consumer groups did still emphasise that customers who are vulnerable, somehow disadvantaged or simply not gaining benefit from the market should be given primary attention.[33]
- Long-term interests of consumers – For retailers, this consideration underscores the stability and continuity of a competitive market for electricity.[34] Consumer groups advocated for linking this consideration to efficient pricing[35] and ensuring the DMO can protect all consumers beyond those on standing offers.[36] These groups also stated that the National Energy Objective[37] already defines this consideration and serves to underscore the centrality of efficiency in the DMO determination.[38]

3.2.2 AER approach to the framework for DMO 8

The AER considers that the overall price needs to be consistent with the objective of being fair, trusted and reasonable in light of the mandatory considerations. Our overarching views and approach to the draft determination are as follows:

- Efficient costs – When we have regard to efficiency, we have considered revealed costs in a competitive market (trade-weighted average environmental costs, average retailer costs to serve, bad debt, smart meter costs), selecting the 50th percentile for wholesale cost modelling, and margins commensurate with undiversifiable risk not accounted for elsewhere in the cost stack.
- Types of customers on standing offers – The AER considers that the type of customer on a standing offer may be one whose level of engagement in the market is less than that of a customer on a market offer. Therefore, this type of customer directly benefits from only a subset of customer acquisition and retention activities. This has been considered in our determination of 'modest' customer acquisition and retention costs.
- Long-term interests of consumers – We have had regard to ensuring consumers are not paying more than they need to but allowing retailers to recover their costs, including an

30 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 7.

31 For example, ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 8; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 4; and EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 3.

32 For example, Customer Consultative Group, Submission to DMO 8 issues paper, 19 November 2025, p. 6.

33 Customer Consultative Group, Submission to DMO 8 issues paper, 19 November 2025, pp. 5–6.

34 For example, ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 1.

35 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 6.

36 SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, p. 7.

37 National Electricity (South Australia) Act 1996 s. 7.

38 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 5.

efficient margin, to ensure the market remains competitive and innovative. We have also had regard to the competitive tension that smaller retailers bring to the market as relevant to the long-term interests of consumers.

- Objective – We have had regard to the concepts of fair, trusted and reasonable, and the provision of an essential service. The AER is also required to have regard to the objective (and the guideline) when making DMO determinations for both the tariffs and the comparison price.[39]

Under the Regulations, the DMO objective is also supported by the DMO guideline,[40] which the AER is to develop prior to DMO 9. The AER will begin consultation on the DMO guideline after the publication of DMO 8 and we will consider whether any additions or qualifications are required as to how the objective and mandatory considerations will be regarded. The new DMO guideline is discussed in section 3.4.

3.3 Who the DMO protects

The Regulations set out that the AER must determine prices for electricity supplied to small customers defined as residential customers and small business customers.[41] The new Regulations expand the coverage of the DMO to standing offer customers across a range of defined tariffs. The AER may also decide to cover other types of tariffs in consultation with stakeholders in future DMO determinations.

The DMO outcomes paper also stated the intention for the DMO to be extended to small customers in embedded networks from DMO 9 onwards.[42]

3.3.1 Tariffs the AER must determine

For DMO 8 the AER is required to create regulated tariffs for:

- residential and small business customers on flat rate tariffs
- residential and small business customers on time of use tariffs
- residential customers with controlled load
- residential customers with smart meters on an SSO.[43]

These regulated tariffs will take the form of a tariff cap, which is defined as a maximum amount of fixed charge and variable charge (the tariff cap) that an electricity retailer may charge small customers of that type in that distribution region in the year for supplying electricity under the regulated tariff of that type.[44]

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39 Regulations, ss. 16(4)(ca) – (cb).

40 Regulations, s. 9A(2).

41 Regulations, s. 6(2)(a) and (b). Small business customers are those that use less than 100 MWh a year. (s6(b)(ii)).

42 DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 6. This is envisaged to be carried out through a later tranche of amendments to commence for DMO 9.

43 Regulations, ss. 16(1A) and 5 (a) – (f) for the definition of *regulated tariff*.

44 Regulations, s. 16(1A)(c).

The AER has discretion to set additional tariff types to receive a regulated DMO tariff cap.[45] The AER has not exercised this discretion for DMO 8 but will consult on whether future DMOs should regulate additional types of tariff caps as part of the DMO guideline development.

Comparison price for non-regulated tariffs and regulated tariffs

Under the Regulations, the AER is required to determine comparison prices for regulated tariffs and non-regulated tariffs. For regulated tariffs, the annual usage and pattern of supply is applied to the tariff cap to convert it to a comparison price for the purpose of calculating discounts in the annual price of market offers in retailer pricing communications. For example, a retailer will calculate the annual cost of a flat rate market offer using the annual usage amount and compare that with the annual cost of the flat rate tariff cap.

We also determine a comparison price that applies to all market and standing offers that are not able to be compared with the regulated tariffs, e.g., because they have different structures or characteristics. Under the Regulations, non-regulated tariff market offers must be compared with the comparison price in retailers' pricing communications, based on the AER's determination of an amount of annual usage and timing or pattern of supply.

3.4 New DMO guideline

The Regulations require the AER to publish a DMO guideline setting out its approach to determining the DMO, and how it will achieve the DMO objective and meet the requirements of the Regulations. The AER is responsible for developing, publishing, maintaining and reviewing the guideline in consultation with stakeholders.

The DMO outcomes paper recommended the introduction of a DMO guideline for better transparency and regulatory certainty. The guideline will allow the AER to state its intended approach to the mandatory considerations and the input assumptions it has made in determinations.[46]

The DMO guideline is required to set out the AER's intended approach and methodology to:[47]

- identifying the cost components the AER proposes to include in the DMO for the tariff caps and comparison price
- determining the cost components of the DMO, including the information and data it intends to use to do so
- considering any additional tariff types that should be regulated as a DMO tariff
- undertaking the DMO determination process each year
- determining the free usage periods for SSO regulated tariffs.[48]

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45 Regulations, ss. 15A and 5(g) for the definition of *regulated tariff*.

46 DCCEEW, *Review Outcomes: 2025 reforms to the Default Market Offer*, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 27.

47 Regulations, s. 18B.

48 Regulations, s. 18B(1).

The DMO guideline may also include guidance on how retailers should use the comparison price in their marketing of retail offers to customers.

The first DMO guideline must be published on the AER's website by 1 December 2026. The AER will commence development of the guideline after the DMO 8 final determination.

3.5 Solar Sharer Offer

The Regulations have introduced a new regulated tariff category under the DMO framework called a Solar Sharer Offer (SSO). The SSO is a time of use standing offer tariff for residential customers with a smart meter that includes a designated 3-hour free power period.

All electricity retailers (with more than 1,000 residential customers across all DMO regions in total) must offer an SSO standing offer tariff. However, the SSO standing offer tariff cannot be used as the default standing offer.[49] Therefore, practically, retailers must provide at least 2 standing offers – a non-SSO standing offer by default and an opt-in SSO standing offer (for those residential customers with a smart meter).

The first phase of implementation begins with DMO jurisdictions on 1 July 2026 for DMO 8, with the potential to expand to other jurisdictions by 2027 following further engagement by the government.

DMO 8 is the first time the AER will determine the SSO. We have set out the regulatory and policy framework together with our proposed approach in chapter 10.

3.6 Standing offer customers

The National Energy Retail Law states that every retailer must have a standing offer and customers have the right to ask for one.[50] However, for those with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms.[51] Customers seeking a standing offer can make that request of their existing retailer, knowing it will be met and that they will be protected by the DMO price cap. Retailers must ensure they comply with this obligation.[52]

See Figure 3.3 for circumstances in which a customer may be on a standing offer.

49 Regulations, s. 11(2).

50 National Energy Retail Law ss. 23 and s. 25.

51 National Energy Retail Law s. 22.

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

Figure 3.3 Standing offer customers[53] [54] [55]

In networks where the DMO applies, a minority of residential and small business customers are on standing offers. Table 3.1 presents the number of customers on standing offers in DMO regions. Most customers on standing offers are served by the 3 largest retailers, referred to as 'Tier 1' retailers – AGL, EnergyAustralia and Origin Energy.

Table 3.1 Customers on standing offers in DMO regions

Customer type	DMO	NSW (number and % of customers)	SE Queensland (number and % of customers)	South Australia (number and % of customers)	Total standing offer customers (number and % of customers)
Residential customers	DMO 8	256,289 (7.3%)	146,674 (9.4%)	60,050 (7.2%)	**463,013 (7.8%)**
Small business customers	DMO 8	45,070 (14.6%)	18,674 (15.7%)	12,846 (14.6%)	**76,590 (14.9%)**

Note: SE Queensland figures extrapolated from all of Queensland by excluding Ergon Energy customers. Other retailers have customers in regional Queensland, so Queensland figures are approximate. Standing offer customers have been calculated by subtracting market offer customers from total customers.
Source: AER retail market performance update, Quarter 1 2025–26.

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

54 Section 10A(3) of the Regulations makes clear that the DMO price only applies to customers on an electricity retailer's standing offer. It does not apply to customers who are on ongoing market contracts where discounts have expired. In practice, these customers may be paying a retailer's standing offer prices. We do not know how many customers may be in this situation.

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

4 Wholesale energy costs

For the DMO 8 draft determination we have decided to:

- use only interval meter controlled load as the basis for our forecast controlled load profile, to improve reflection of market outcomes and account for the discontinuation of AEMO's controlled load profile
- adopt the 50th percentile wholesale energy cost (WEC) estimate and apply a volatility allowance, to better reflect an appropriate balance of risk and to ensure wholesale costs in the DMO reflect the efficient costs to supply standing offer customers
- not include the Australian Securities Exchange's (ASX) new morning and evening peak contracts in the simulated hedging strategy, due to their lack of traded volume
- calculate time of use WECs so they reflect the underlying spot price of electricity in each charging window.

Wholesale costs represent 32% to 44% of the total DMO price for flat rate residential and small business customers. Wholesale costs have decreased by 3% to 12% since DMO 7, depending on the DMO region.

The Regulations direct the AER to have regard to the wholesale cost of electricity when determining the DMO. The Amendments also require the AER to have regard to the efficient costs for small customers on standing offers, the types of customers on standing offers and the long-term interests of consumers.

To establish an efficient forecast of wholesale costs for the DMO, we aim to reflect how a prudent retailer might purchase energy. This involves forecasting demand (also known as load) and electricity spot market outcomes, as well as building a hypothetical hedging strategy to protect the retailer and its customers against the extreme price volatility that can occur in the wholesale spot market.

The largest component of our wholesale cost forecast is the wholesale energy cost (WEC), which is a function of energy supply and demand forecasts, the assumed hedging strategy of a retailer to manage their spot market risk and any final exposure to the spot market. Other minor components, such as ancillary and prudential costs, are added to the WEC to determine total wholesale costs in the DMO. We use an external consultant, ACIL Allen, to assist us with determining wholesale costs in the DMO.

4.1 Issues paper

4.1.1 Controlled load profile

The issues paper consulted on options for deriving a controlled load profile, which the wholesale cost modelling has historically used as a basis to forecast controlled load demand. We also consulted on whether the selected option should be applied uniformly across regions and whether to remove interval meter controlled load energy from the general use load profile.

The issues paper explained that the wholesale cost model has historically used the Australian Energy Market Operator's (AEMO) sample Controlled Load Profile, which was based on accumulation meters, as a basis to forecast the shape of controlled load demand for the upcoming DMO determination year. However, AEMO discontinued production of the Controlled Load Profile for NSW regions in late 2024[56] and for South Australia on 1 July 2025.[57] In both instances, this was requested by the relevant state government, to alleviate the costs associated with maintaining controlled load sample meters. Energex is the only DMO region where AEMO still publishes a sample Controlled Load Profile. By the commencement of DMO 8, AEMO's historical Controlled Load Profile will be out of date by more than one year in South Australia and by more than 2 years in NSW regions. In regions where AEMO's Controlled Load Profile has been discontinued, accumulation meter controlled load energy is now settled against the Net System Load Profile (NSLP).

The issues paper noted we had obtained interval meter controlled load data from all 5 DMO distribution network service providers (DNSPs) and that we intended to use this data as the basis for our controlled load profile. We considered that this solved the issue of the discontinued AEMO Controlled Load Profile, while improving the accuracy of our modelled controlled load profile because more than half of controlled load customers will be settled on an interval meter during DMO 8. This proportion will continue to increase notably each year as the Australian Energy Market Commission's (AEMC) Accelerating smart meter deployment rule change[58] continues to drive uptake of interval meters, including for controlled load customers.

However, the issues paper explained that this approach on its own would not account for accumulation meter controlled load customers, who would still make up a significant portion of overall controlled load demand. The issues paper proposed 3 options for data to be used to simulate controlled load demand for DMO 8. These were:

- **Option 1:** Use only the interval meter controlled load profile.
- **Option 2:** Blend the interval meter controlled load profile with AEMO's historical accumulation meter Controlled Load Profile.
- **Option 3:** Blend the interval meter controlled load profile with the NSLP.

The issues paper noted we would evaluate each option against 4 considerations:

- **Reflection of market outcomes** – we considered we should strive to include controlled 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).
- **Longevity of the decision** – we are aware that consistency in the DMO methodology remains important to stakeholders. We considered how any decision on controlled load profiles may continue to be upheld as market conditions change.

56 AEMO, NSW CLP Final Determination, Australian Energy Market Operator, 30 May 2024, p. 3.

57 AEMO, Final Determination – Removal of Controlled Load Profiles - SA, Australian Energy Market Operator, p. 7.

58 AEMC, National Electricity Amendment (Accelerating Smart Meter Deployment) Rule, Australian Energy Market Commission.

- **Continuity between determinations** – we considered that we should avoid drastic changes to the methodology where possible, to minimise confusion and regulatory burden. Where available, we would aim to select options that serve as updates to the prior methodology, rather than fundamental changes to it.

The issues paper also sought feedback on whether to apply a consistent approach in simulating the controlled load profile for Energex, where AEMO's Controlled Load Profile is still published.

Finally, the issues paper noted that the interval meter dataset used to simulate the interval meter portion of the load profile for 'residential customers without controlled load' (general use) did not exclude interval meter customers with controlled load. We proposed to use the DNSP-provided interval meter controlled load profiles to identify the volume of interval meter controlled load present in the general use dataset and remove it.

4.1.2 Percentile WEC estimate and volatility allowance

The issues paper consulted on whether the WEC percentile estimate should be reduced from the 75th to the 50th percentile. This consultation was prompted by findings from *Assessing the performance of the wholesale cost model*,[59] a supplementary report we published alongside the issues paper.

As requested by some retailers, the supplementary report tested the performance of hedging strategies used in past DMO determinations against actual spot market outcomes from their respective determination years. The analysis found that the 75th percentile estimate had typically resulted in overestimation of the WEC that a retailer using a similar hedging strategy would have incurred. Instances of overestimation were both more common and larger than instances of underestimation across the 5-year period analysed. At the 50th percentile, the rate of overestimation remained the same as the 75th percentile but the average size of overestimations was slightly reduced.

The issues paper noted that the AER had historically selected the 75th percentile WEC estimate to provide retailers with a buffer against unexpected volatility. However, the paper acknowledged that the supplementary report's findings indicated this buffer would still exist at the 50th percentile, without allocating disproportionate risk to consumers.

The issues paper considered that a reduction in the WEC percentile would be merited under both the previous and amended Regulations. It also indicated that the 50th percentile likely aligns more closely with the requirement to consider efficient costs, since it is the median forecast outcome so would compensate retailers for the expected cost of prudent hedging. The 75th percentile was considered less aligned with efficient costs, compensating retailers for a more volatile than expected outcome and increasing the WEC estimate above the efficient level in most years.

The issues paper also consulted on whether a volatility allowance should be included in the wholesale cost if the 50th percentile WEC was adopted, to replace the risk buffer provided to retailers by the 75th percentile. The paper considered that a risk buffer may already exist at the 50th percentile, given the frequency and scale at which it had been shown to

59 AER, Assessing the performance of the wholesale cost model, Australian Energy Regulator, 5 November 2025.

overestimate the WEC. We considered this likely made the volatility allowance unnecessary, but we acknowledged that some stakeholders may hold different views.

4.1.3 Risk management costs arising from solar exports

The issues paper stated our intention to continue to exclude solar exports from the interval meter dataset used to create blended load profiles for wholesale modelling. We considered that since the DMO is a price charged by retailers for customers' imports (or consumption), this should be reflected in the load profiles used in the wholesale cost methodology.

We reflected on previous stakeholder submissions and analysis on this topic from previous DMO determinations. We did not consider a change in our approach was required under the Regulations, noting there are various ways retailers can manage potential risks (and potentially benefit) from customers' solar exports.

4.1.4 New morning and evening peak contracts

The issues paper noted the introduction of the ASX's new morning and evening peak contracts but considered that limited traded volumes of these products meant that inclusion in the modelled hedging strategy for DMO 8 was likely not justifiable. The paper acknowledged the possibility that traded volumes of these products may increase in the future. We sought stakeholder views on what parameters should be considered when deciding whether a new product should be included in the hedging strategy.

4.1.5 Time of use wholesale energy costs

Prompted by the DMO reforms, which require the AER to determine time of use tariffs, the issues paper consulted on how the WEC should be calculated for time of use offers.

We proposed adopting a similar approach to that used by the Queensland Competition Authority (QCA). The suggested approach would involve dividing the load profile into specified time periods and calculating a ratio for each, based on the demand-weighted price for the individual period compared with the overall load profile. The WEC would then be scaled according to these ratios in each time of use period.

We considered this method ensured that the sum of time of use WECs would be equal to the flat rate WEC on an annualised, consumption-weighted basis, while still reflecting the varying wholesale cost of electricity throughout the day. We also considered the method to be objective and transparent, allowing stakeholders to clearly understand and verify how wholesale costs are apportioned across time periods.

We sought stakeholder views on whether this approach was appropriate or if an alternative method would be more suitable.

4.2 Stakeholder views

4.2.1 Controlled load methodology

Most stakeholders supported option 1 – to use exclusively interval meter controlled load data.[60] Stakeholders that supported option 1 favoured it for its simplicity and reflection of the long-term market outcomes. These stakeholders considered the absence of accumulation controlled load data to be a temporary problem, because the prevalence of accumulation meters will decline continuously in the next few years as the smart meter rollout progresses. The JEC also encouraged a more detailed assessment of the prevalence of metering types and any difference in respective load profiles.

Some stakeholders supported option 2 – blending the interval meter controlled load profile with AEMO's historical Controlled Load Profile.[61] These stakeholders considered option 2 to be most cost reflective because it accounts for both interval and accumulation customers. ENGIE further suggested that, as the smart meter rollout continues, the reliance on AEMO's historical accumulation meter Controlled Load Profile will naturally decline and the DMO methodology can transition to an approach that solely uses the interval meter controlled load profile.

Only AGL supported option 3 – blending interval meter controlled load with the NSLP.[62] AGL considered it important to incorporate accumulation meter controlled load and considered option 3 used the most up-to-date data to do this. However, 1st Energy specifically opposed option 3, stating that the NSLP would not isolate controlled load behaviour.

Although AGL supported option 3, it also expressed support for adopting a consistent approach in simulating the controlled load profile across all regions. ActewAGL also supported a consistent approach. No other stakeholders commented on this specific issue.

No feedback was received on whether the interval meter controlled load should be removed from the general use interval meter load profile.

4.2.2 Percentile WEC estimate and volatility allowance

Submissions demonstrated that retailers and consumer groups hold opposing views regarding the percentile estimate. All retailer submissions opposed any reduction in the WEC estimate, with some submissions proposing that a percentile higher than the 75th should be

60 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 4; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 6; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 3; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 10.

61 AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 December 2025, p. 2; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 4–5; Energy Trade, Submission to DMO 8 issues paper, 27 November 2025, p. 2.

62 AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 4–5.

adopted.[63] Conversely, all consumer group submissions supported reducing the WEC estimate from the 75th to the 50th percentile and, in some cases, considered that a percentile estimate lower than the 50th should be adopted.[64]

Many retailers submitted that it would be inappropriate to reduce the WEC percentile estimate since uncertainty and risk in the wholesale market would likely increase in the near future.[65] The submissions identified a broad range of potential risk drivers, including volatility of demand driven by uptake of consumer energy resources (CER), upcoming changes to policy settings (the Solar Sharer Offer, SA Firm Energy Reliability Mechanism and the NEM wholesale market settings review) and evolving market characteristics (weather, generation mix, electrification and transmission build). In general, the submissions considered that the presence of multiple risk drivers that could soon materialise or intensify should result in the percentile estimate being increased, rather than reduced.

Additionally, many retail stakeholders considered the supplementary report's finding that the 50th percentile underestimated wholesale costs in 16% of instances constituted evidence that a higher percentile estimate is needed to facilitate recovery of efficient costs.[66] EnergyAustralia stated that the finding is inconsistent with the principle that retailers should recover their efficient costs, while Origin Energy stated that underestimation in 'a significant number of plausible scenarios' poses unacceptable financial risk.

Several retailer submissions expressed concern that a lower percentile estimate assumed retailers would not sufficiently hedge spot price risk and may encourage riskier hedging practices.[67] ENGIE stated that the 50th percentile does not reflect an efficient hedging strategy since it 'assumes that retailers would not sufficiently hedge against potential

63 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, pp. 4–5; AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 2; AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 5–7; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 2–6; Energy Trade, Submission to DMO 8 issues paper, 27 November 2025, p. 2; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 5–6. EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, pp.7–8; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 5–6; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, pp. 2–3; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 1–6; Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 3; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4.

64 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 4–11; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 11–12; SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, p. 11.

65 AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 5–7; ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, pp. 4–5; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, pp. 7–8; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 5–6; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, pp. 2–3; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 1–6; Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 3; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4.

66 AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 2; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 2–6; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, pp. 7–8; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 1–6; Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 3.

67 Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 2–6; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 5–6; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, pp. 2–3; Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 3; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4.

downside risks and volatility'.[68] GloBird Energy similarly stated that the 50th percentile does not allow for the costs retailers incur in managing low probability but severe outcomes.[69] Similarly, Powershop expressed concern that moving to the 50th percentile could indirectly encourage retailers to accept greater risk by reducing their hedging and risk management practices.[70] Other retailers, including 1st Energy and Alinta Energy, noted that spot prices are asymmetrically skewed to the upside and stated that the 50th percentile does not allow retailers to protect against this tail risk.[71]

Retailers also expressed concern that the modelled hedging strategy results in an unrealistic degree of exposure to the spot price. AGL stated that this hedging approach could create significant risk in practice,[72] while Energy Trade considered that 'no prudent retailer with proper governance and risk reporting would tolerate such exposure'.[73] Origin Energy reiterated its view from previous determinations that a high level of modelled cap payouts was driving the composition of the hedging strategy to adopt a large number of cap contracts, causing the exposure.[74]

Some retailers expressed concerns that a reduction in the WEC percentile estimate would add additional risk alongside reductions in other parts of the cost stack and advocated for the percentile estimate to be calibrated holistically with other elements of the DMO. ActewAGL stated that reductions across multiple cost stack elements would negatively impact the ability of smaller retailers to compete,[75] while Alinta Energy noted it could undermine the financial resilience of retailers and damage the long-term interests of consumers.[76]

Similarly, retailers raised concerns that reducing the WEC percentile could have disproportionate impacts on smaller retailers. Powershop noted that larger retailers typically have greater access to working capital and larger balance sheets, allowing them to manage variability in wholesale costs more readily.[77] Powershop stated that, by contrast, smaller retailers have more limited financial buffers; therefore, they hedge more conservatively to manage risk and maintain financial viability. Origin Energy noted that the risk of under-recovery would be particularly difficult for small retailers to manage.[78]

AGL and Origin Energy considered that the potential for forecast error also makes a higher percentile estimate more suitable and referred to historical quotes from ACIL Allen on the potential for forecast error in the modelling process.[79] AGL also considered that the AER's

68 ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 5.

69 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 2.

70 Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 3.

71 Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 3; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4.

72 AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 5–7.

73 Energy Trade, Submission to DMO 8 issues paper, 27 November 2025, p. 2.

74 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 1–5.

75 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, pp. 4–5.

76 Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 2–6.

77 Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 3.

78 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 1–5.

79 AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 5–7; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 1–5.

consultation on adopting the 50th percentile contradicted the supplementary report's finding that there was no systematic underestimation or overestimation in the modelling process.[80]

GloBird Energy requested that the AER publish the full WEC distribution from all simulations, expressing concern that the distribution may not be even and that risk could be skewed toward extreme market outcomes.[81]

Consumer groups supported a reduction of the WEC percentile from the 75th to the 50th.[82] The submissions emphasised the supplementary report's finding that overestimation of the WEC has been frequent and usually occurred by a significant margin. Consumer groups considered that this has resulted in retailers over-recovering costs from consumers persistently and substantially during the past 5 years. Energy Consumers Australia (ECA) noted that this would have amounted to a household in the Ausgrid region paying $82 more than necessary over the DMO 6 period and a small business in Ausgrid's region paying $210 more than necessary over the same period.[83] The ECA noted that over-recovery would have been greater in regions like Endeavour Energy, where the difference between the 75th percentile and actual wholesale costs was greater and modelled usage assumptions are higher.

The ECA, the JEC and SACOSS also agreed that the 50th percentile is more in line with efficient costs to supply standing offer customers, noting that this position is supported both by the findings of the supplementary report and the amended DMO regulations. The JEC considered that 'the additional risk premium incorporated into the 75th percentile WEC estimate is incompatible with the mandatory consideration of efficient costs to serve customers and is broadly neither fair nor reasonable'.[84]

The ECA and the JEC also advocated for consideration of a percentile estimate lower than the 50th, since overestimation had been both larger and more frequent than underestimation even at the 50th percentile.[85] Both stakeholders advocated for additional analysis to determine a percentile below the 50th where no persistent over-recovery from consumers would occur.

Volatility allowance

Most retailers considered that a volatility allowance would be necessary if the 50th percentile was adopted, since it would partly offset instances of underestimation of the WEC.[86]

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80 AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 7.

81 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 3.

82 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 4–11; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 11–12; SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, p. 11.

83 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp.4–5.

84 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 11.

85 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp.4–5; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 11.

86 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 5; AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 2; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 3; Energy Trade, Submission to DMO 8 issues paper, 27 November 2025, p. 2; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 7; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 5–6; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 6.

However, most retailers considered the volatility allowance a 'suboptimal' outcome that would be unnecessary if a higher percentile was selected, noting it would introduce unnecessary complexity that could be avoided by selecting a higher percentile.[87] 1st Energy recommended that any volatility allowance would need to account for historical and modelled outcomes across a range of physical and financial market factors.[88]

All 3 consumer group submissions considered a volatility allowance would be unnecessary and contrary to the requirement to consider efficient costs, since persistent over-recovery from consumers had been observed at the 50th percentile.[89] The ECA submitted that, given the DMO's consumer protection objective and the removal of the requirement for the AER to consider retailer profits, any allowance for volatility should be subtracted from the WEC, so that it would accrue to consumers.[90] The JEC considered that making an explicit provision for volatility within the DMO could weaken incentives for retailers to efficiently manage wholesale risk themselves.[91]

4.2.3 Risk management costs arising from solar exports

We did not receive any feedback on our intention to continue excluding solar exports from the interval meter dataset used to create blended load profiles for wholesale modelling.

4.2.4 New morning and evening peak contracts

No stakeholders supported including the new morning and evening peak contracts in the DMO 8 hedging strategy, although GloBird Energy stated that this could be considered if over-the-counter (OTC) trades were counted toward total traded volume.[92]

EnergyAustralia and GloBird Energy suggested that the limited volume traded on the ASX is not due to product deficiency, but rather that similar products were more likely to be traded on the OTC market.[93] GloBird Energy recommended the contracts be included in the hedging strategy for future determinations, with such considerations being informed by volumes traded OTC as well as on the ASX.[94]

Most stakeholders viewed liquidity and traded volume as key parameters to consider when deciding whether to include the new peak contracts in the modelled hedging strategy.[95] Origin Energy recommended that the new peak contracts be included in the hedging strategy

87 AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 2; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, pp. 7–8; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 6.

88 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4.

89 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp.5–11; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 11; SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, p. 11.

90 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 11.

91 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025

92 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, pp. 3–4.

93 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, pp. 3–4; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 8.

94 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 4.

95 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 5; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 8; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 8.

for future determinations if their traded volume were to exceed 10% to 15% of scheduled demand.[96] The AEC, AGL and EnergyAustralia considered the frequency of trading another key parameter that should be considered. 1st Energy suggested a range of other parameters, including correlation with usage profiles, availability and cost of the product in forward market, counterparty credit risk, effectiveness in covering exposure from time of use and export profiles, and operational complexity.[97]

ENGIE recommended the AER continue to monitor the market for trade of the new peak products on an ongoing basis.[98]

4.2.5 Time of use WECs

Most stakeholders supported the proposed approach to estimating time of use WECs, considering it reasonable, transparent and without unnecessary complexity.[99] The AEC highlighted that time of use structures are becoming increasingly important in retail pricing given the growing uptake of interval meters.[100]

While broadly supportive of the approach, several stakeholders made additional suggestions:

- a time of use DMO should maintain the same WEC as a flat rate offer but vary recovery throughout the day[101]
- using a gross load profile is not reflective of the profile retailers hedge against[102]
- the AER provide detailed bottom-up information for each time of use period[103]
- the approach should use sufficiently granular interval data and consider export flows and evolving load shapes.[104]

4.3 Draft determination

4.3.1 Controlled load methodology

We have decided to use only the interval meter controlled load data (option 1) to simulate controlled load demand for the DMO 8 draft determination. This approach will apply uniformly to all DMO regions, including Energex.

As per the issues paper, we assessed each option against 4 considerations: reflection of market outcomes, data transparency, longevity of the decision and continuity between

96 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 6.

97 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4.

98 ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 5–6.

99 AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 2; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 8; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 6; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 5–6; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 3–4.

100 AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 2.

101 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 6.

102 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 5.

103 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 8.

104 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 3.

determinations. We consider option 1 best satisfies these criteria. We also note that option 1 received the most stakeholder support of the options proposed.

Option 1 results in the most accurate reflection of market outcomes, since it directly accounts for the load shape of interval meter controlled load customers, who represent the majority of controlled load customers in DMO regions. Option 1 is also fully transparent – we have published the DNSPs' interval meter controlled load profiles alongside this draft determination.

We also consider option 1 to have the best longevity of any available option because it will become increasingly more representative of controlled load customers' demand as the transition to interval meters continues, in line with the smart meter rollout. On this basis, option 1 is the only option that would not need to be reconsidered in future determinations. We also consider that option 1 satisfies continuity between determinations, since it maintains the use of a controlled load profile while increasing the size and market reflectivity of the sample, rather than being a fundamental change to the methodology.

We agree with stakeholders that reflecting accumulation meter controlled load demand would be ideal if doing so robustly met the decision criteria. However, we have concerns about the ability of option 2 to accurately reflect market outcomes and its longevity.

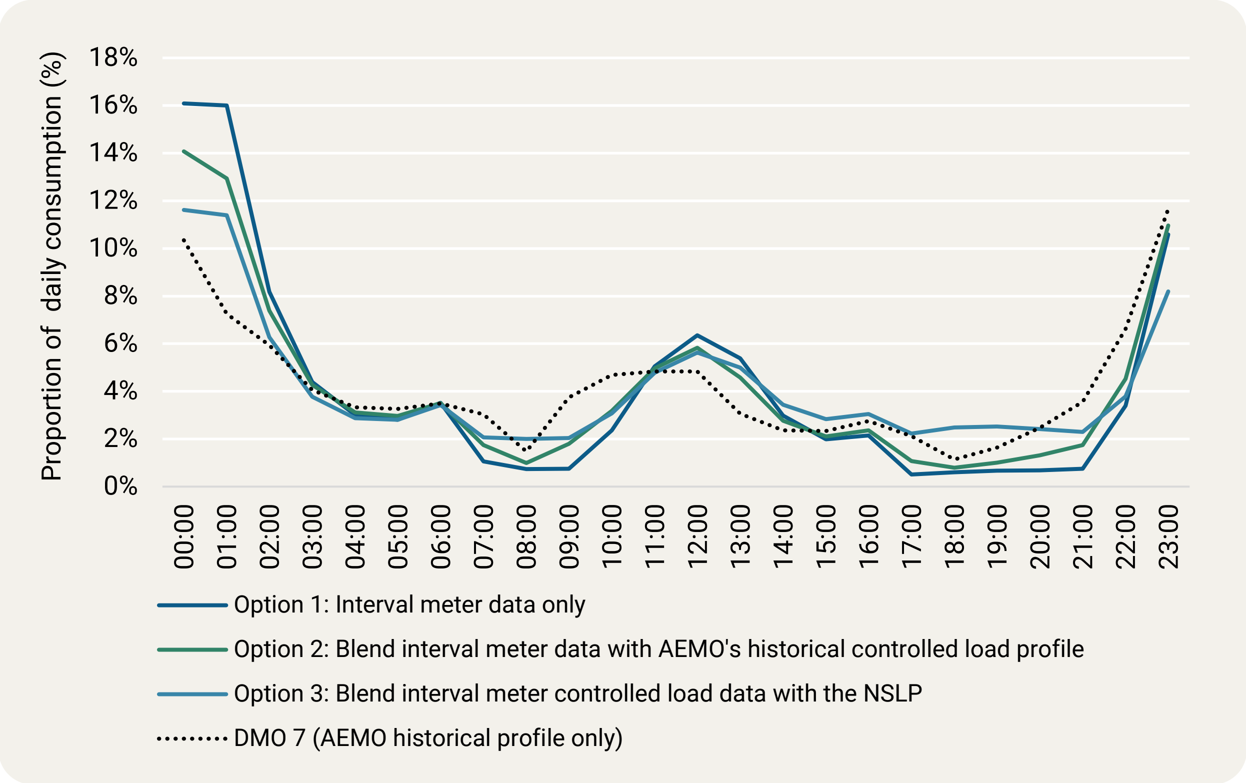
Option 2 relies on historical accumulation meter Controlled Load Profile data, meaning that blending this with current interval meter controlled load data would introduce a mismatch in the underlying demand conditions under which the data were observed. We consider this would limit option 2's ability to reflect market outcomes. Similarly, the extent to which the shape of accumulation meter controlled load demand has changed since AEMO ceased production of the sample Controlled Load Profile is unclear, and the difference is likely to be more material with each passing determination. We consider this significantly limits option 2's longevity because the extent to which the historical Controlled Load Profile remains reflective would likely need to be reassessed each year.

Similarly, we do not consider that option 3 – blending the interval meter controlled load profile with the NSLP – results in an accurate reflection of market outcomes. The profile resulting from option 3 showed significant peak demand, which controlled load dispatch typically avoids. We agree with 1st Energy that the shape of the NSLP reflects the general use profile of residential and small business customers and does not isolate controlled load behavior.[105]

Figure 4.1 to Figure 4.5 show the controlled load profile under each option for all regions. As observed in the issues paper, the use of interval meter controlled load data results in greater midday controlled load demand than the historical accumulation meter sample profile. We consider this reflects both the significantly larger sample of interval meters and underlying differences in demand patterns between meter types. As noted in the issues paper and the DMO 7 final determination, DNSPs are increasingly permitting retailers to orchestrate the controlled load demand of their interval meter customers. This appears to have driven greater interval meter controlled load dispatch during solar hours, due to the abundance of low and negative prices at that time.

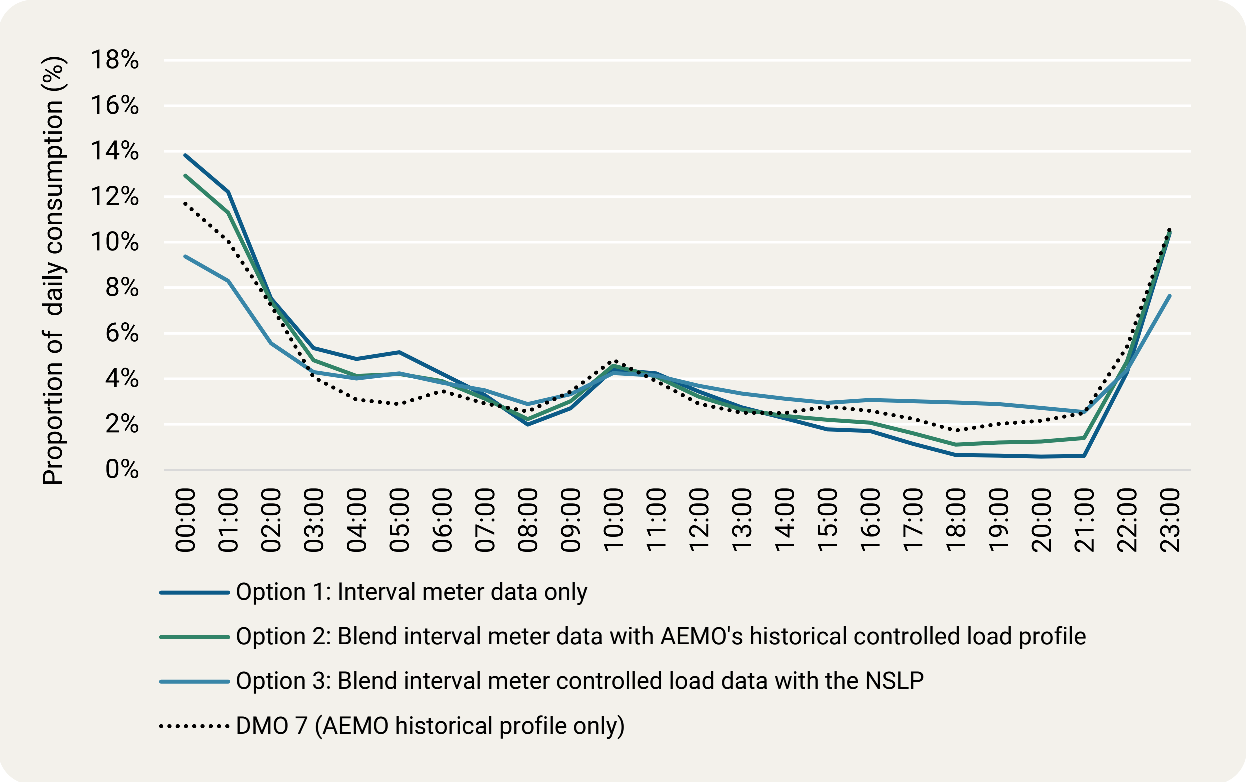
105 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 3.

Figure 4.1 Options for simulating the controlled load profile, Ausgrid, CL1



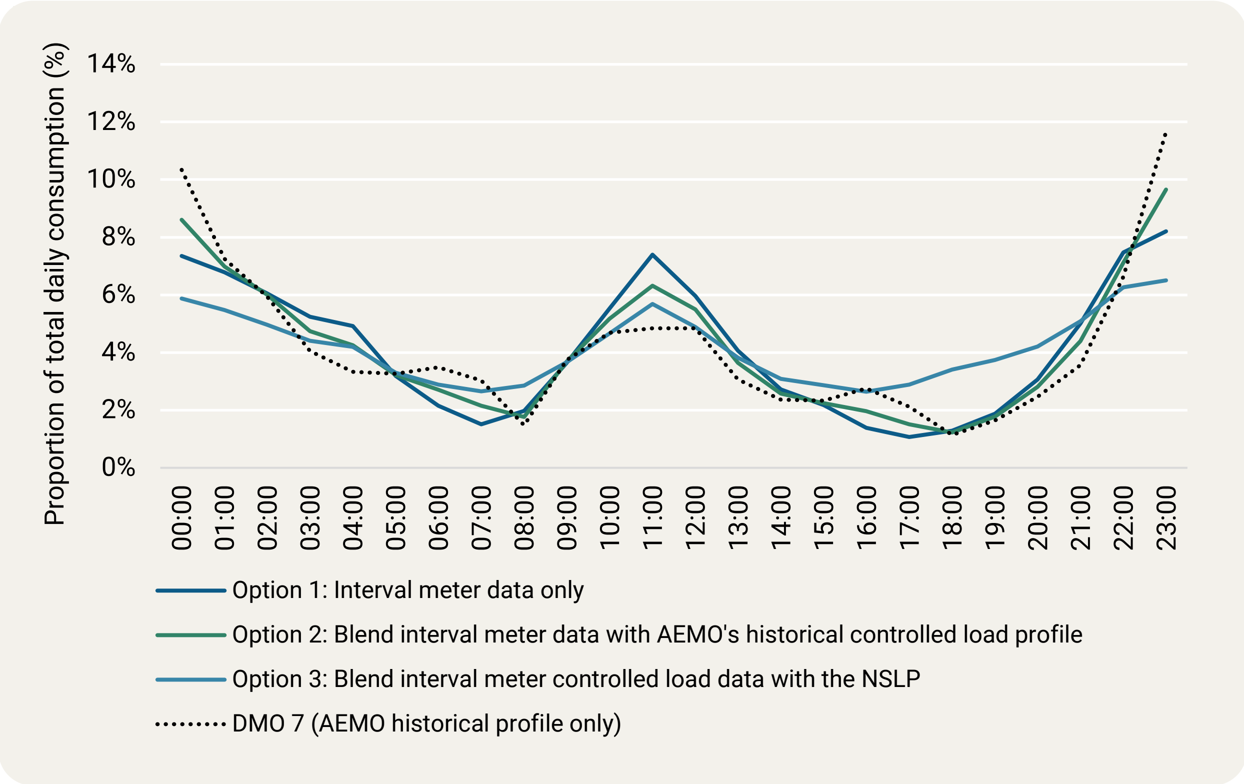
Note: AER analysis using AEMO, Ausgrid data. Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2025.

Figure 4.2 Options for simulating the controlled load profile, Endeavour Energy, CL1



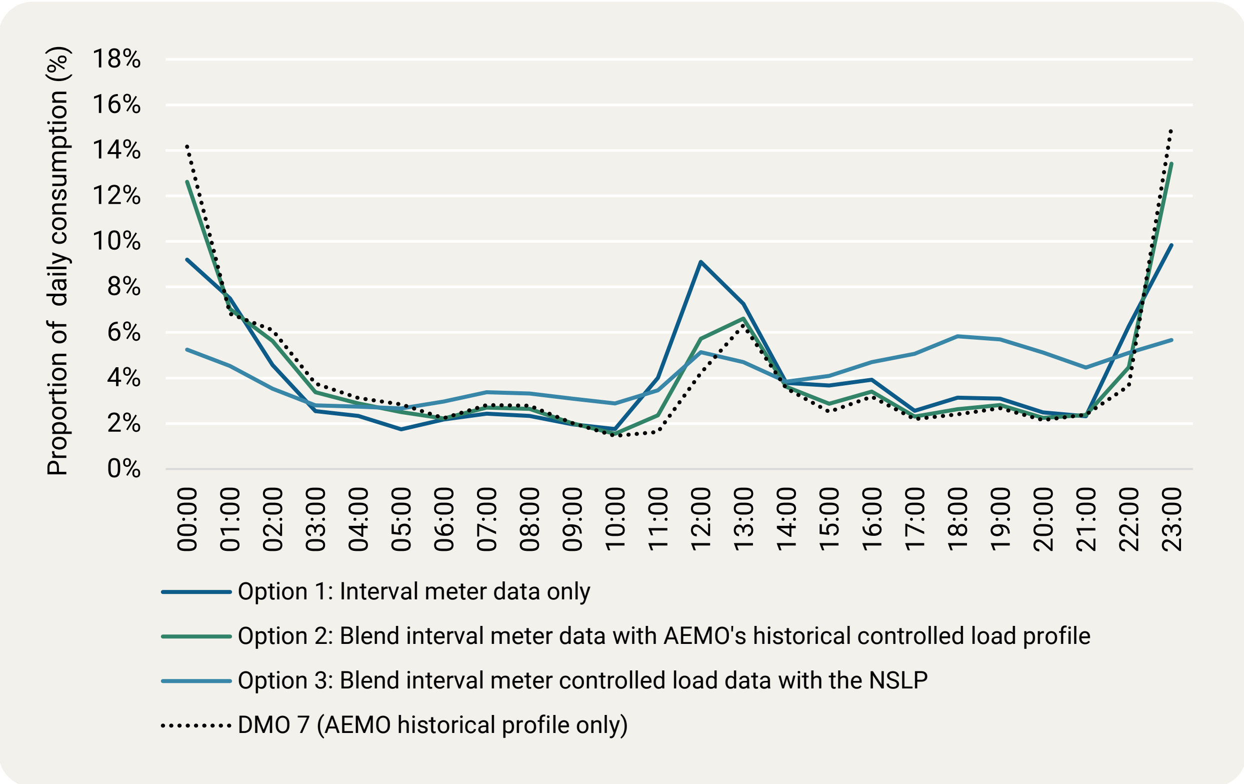
Note: AER analysis using AEMO, Endeavour Energy data. Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2025.

Figure 4.3 Options for simulating the controlled load profile, Essential Energy



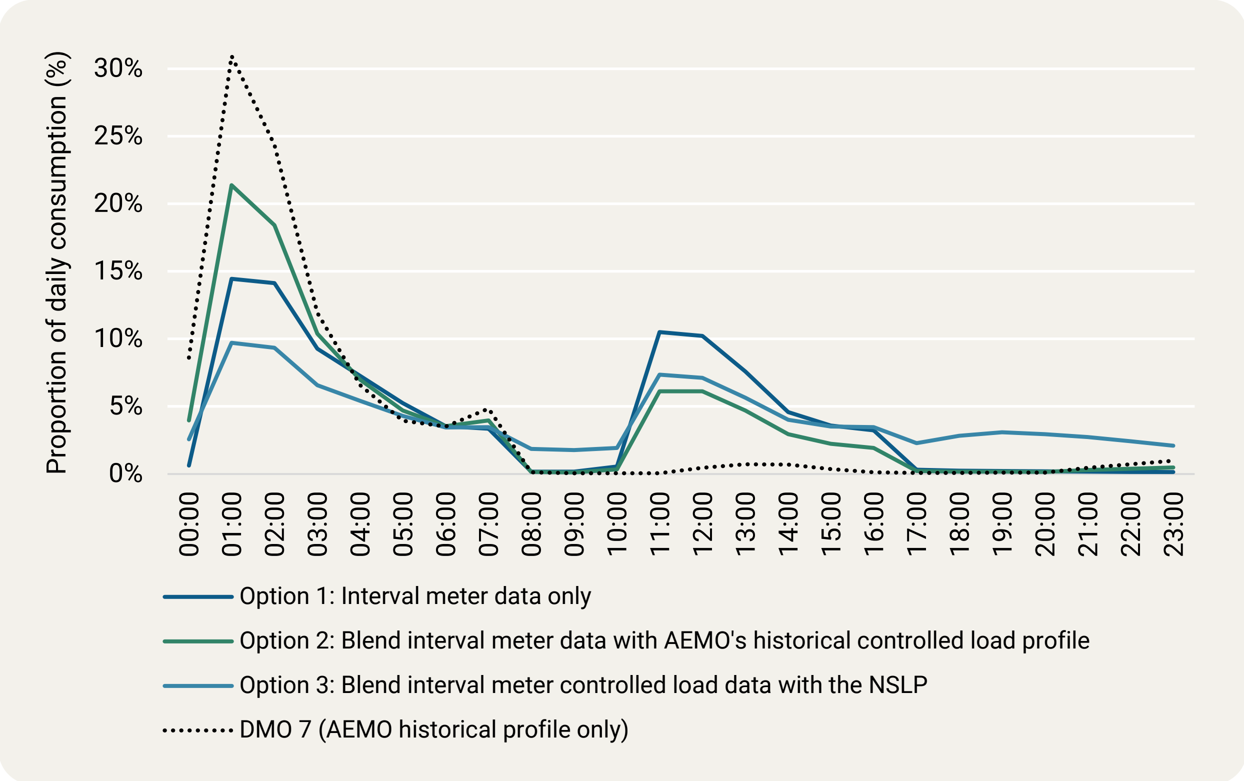
Note: AER analysis using AEMO, Essential Energy data. Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2025.

Figure 4.4 Options for simulating the controlled load profile, Energex, CL1



Note: AER analysis using AEMO, Energex data. Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2025.

Figure 4.5 Options for simulating the controlled load profile, SA Power Networks



Note: AER analysis using AEMO, SA Power Networks data. Load profiles depicted are the average daily shape of controlled load demand across all 30-minute periods from 1 October 2023 to 30 September 2025.

We have also decided to use the DNSP-provided interval meter controlled load data to identify and remove interval meter controlled load demand from the general use interval meter profile. We consider this results in a more accurate general use profile and we did not receive any feedback from stakeholders on this issue.

4.3.2 Percentile WEC estimate and volatility allowance

We have decided to adopt the 50th percentile WEC estimate and apply a volatility allowance for residential and small business customers in our draft determination. The volatility allowance is designed to reflect the cost of holding capital to cover forecast risk. It will be calculated by multiplying the difference between the 100th and 50th percentiles by the weighted average cost of capital (WACC). The volatility allowance will be a variable cost component and, as such, is reflected in the usage charge of the DMO tariff caps.

We consider that the results of the back-cast analysis detailed in the supplementary report demonstrate that the 50th percentile best reflects our requirement to consider the efficient costs to supply an essential service.[106] The 50th percentile is the median forecast cost outcome; therefore, it is the expected cost of prudent hedging. Conversely, the 75th percentile assumes a higher-than-expected cost outcome, which would set the WEC above the expected cost of prudent hedging, raising it above the efficient level.

We consider adoption of the 50th percentile strikes the right balance between the requirement to consider efficient costs and preserving retail competition, which is aligned

106 AER, Assessing the performance of the wholesale cost model, Australian Energy Regulator, 5 November 2025.

with the long-term interests of consumers. The choice of percentile estimate is ultimately a decision about the extent to which consumers or retailers should bear the risk that actual wholesale cost outcomes may differ from those forecast. We consider this forecast risk should be allocated evenly, which is achieved through adopting the median forecast estimate – the 50th percentile. As indicated by the results of the back-cast analysis, the 50th percentile will usually allow most retailers to recover their efficient costs, while reducing the scale of overestimation observed at the 75th percentile.

However, the back-cast analysis also indicated that the WEC was underestimated in a minority of instances at the 50th percentile. While rare and usually limited in scale, this could result in instances of wholesale cost under-recovery, which may adversely impact retailer viability. We consider that these risks may be particularly difficult for smaller retailers to manage, because scale and capital constraints can limit their hedging efficiency and the strength of their balance sheets. We consider that retailer viability is integral to retail competition so is aligned with the long-term interests of consumers, which we must consider under the amended regulations. Therefore, we have decided to include a volatility allowance in our draft determination to provide an allowance to retailers for any differences in actual costs compared with those forecast.

We received a significant amount of feedback in response to our consultation on this issue. In many cases, similar views were raised across different submissions. Below we have responded to these on an issue-by-issue basis to assist stakeholders in understanding how views raised in the submissions were factored into our decision.

Wholesale market risk and uncertainty

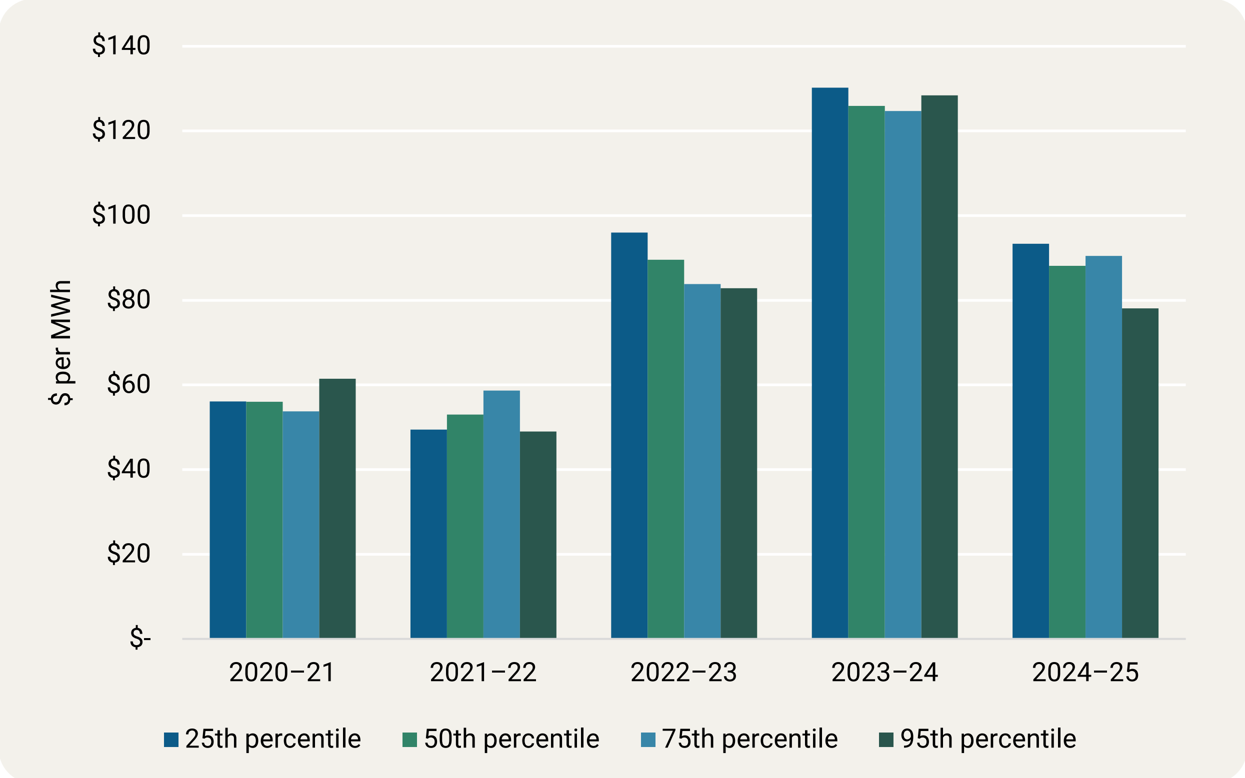
We acknowledge some retailers' views that it is counterintuitive to decrease the percentile estimate in the context of growing uncertainty in the wholesale market. However, we do not consider that the identification of new or heightened risk drivers is relevant to the percentile decision, which determines the distribution of risk between consumers and retailers, rather than the existence of risk itself.

As discussed in the supplementary report, the WEC percentile estimate represents a specific result from one of the more than 600 spot price simulations conducted by our wholesale consultant. The underlying inputs and assumptions are held constant across simulations. Therefore, changes between simulations consist only of the timing and duration of baseload outages, weather-driven timing of renewable generation availability and weather-driven timing and scale of demand, which combine to drive differences in realised spot prices. Accordingly, variations in WEC estimates are a result of variations in projected forecast wholesale cost outcomes, rather than changes to specific modelling inputs or a different hedging strategy.

The wholesale modelling explicitly accounts for evolving market conditions through annual updates to inputs and assumptions, ensuring that known risks are embedded at every percentile. Core inputs (including areas of concern for retailers such as the generation mix, load profiles, transmission build and policy settings) are updated annually using the most recent available data and applied uniformly across all simulations. As a result, higher percentiles do not represent additional or more intense risks, but simply more extreme realisations of stochastic interactions between risk elements.

Figure 4.6 demonstrates that emerging risk drivers affect all percentiles in a similar way. For example, as market conditions became more volatile after the market events of mid-2022, modelled spot prices increased uniformly across all percentiles.

Figure 4.6 Average modelled spot prices across percentiles, Energex



Source: AER analysis using ACIL Allen data.

We also consider that some of the uncertainties identified by retailers, including the commissioning of Project Energy Connect, the South Australia Firm Energy Reliability Mechanism and the recommendations of the NEM wholesale market settings review, could plausibly decrease wholesale costs if they succeed in improving liquidity or availability of generation capacity across regions.

Since all known material and structural risks are accounted for at every percentile, we consider that any forecast risk associated with these uncertainties should be allocated evenly between consumers and retailers, which is achieved through adoption of the 50th percentile. However, we acknowledge the potential for unforeseen impacts on wholesale costs that may occur after the final determination. The potential cost of these is mitigated by the inclusion of the volatility allowance, which applies in addition to the WEC.

We note AGL and Origin Energy's reference to historical quotes from ACIL Allen about the potential for forecast error, and that this is one reason a higher percentile may be justified.[107] These specific comments by ACIL Allen were made prior to production of the back-cast analysis and in the context of the old Regulations. The comments reflect a perception that forecast error may be biased toward underestimation of the WEC, but the back-cast analysis did not indicate that such a bias exists. Similarly, the comments reflect a perception that

107 AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 6; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 4–5.

underestimation is worse than overestimation, which is consistent with the DMO objective under the previous Regulations to allow retailers a reasonable profit. However, this objective is no longer included in the Regulations that govern the AER's consideration of DMO prices and has since been replaced by mandatory considerations of efficient costs and the role of electricity as an essential service.

We disagree with AGL's position that our consultation on adoption of the 50th percentile contradicts the supplementary report's finding that there is no systematic underestimation or overestimation in the wholesale modelling. We consider that since forecast error has not been biased in any direction, forecast risk should be allocated evenly between consumers and retailers. This outcome is achieved through adoption of the 50th percentile.

Risk of under-recovery

We consider that retailers' concerns about the possibility of under-recovery in a minority of instances are sufficiently addressed through the inclusion of a volatility allowance. A volatility allowance will cover the cost of holding capital to ameliorate a potential wholesale cost underestimation in all regions and determination years, despite the back-cast analysis indicating that such underestimations occur infrequently in practice.

We acknowledge that retailers' preferred solution in this instance was to retain the 75th percentile or adopt a higher percentile. However, we consider the back-cast analysis demonstrated that this allocates disproportionate forecast risk to consumers. At the 75th percentile, overestimation was 5 times more common than underestimation and occurred at triple the magnitude. The 4 instances of underestimation were an average of 4% below the actual WEC. Comparatively, the 21 instances of overestimation were an average of 13% above the actual WEC. While the frequency of overestimation and underestimation was unchanged at the 50th percentile, the difference in magnitude decreased but was still skewed toward overestimation.

We also understand that, as raised in some submissions, smaller retailers may have weaker balance sheets, along with structural constraints that can limit their hedging efficiency or flexibility, resulting in higher wholesale costs. This may cause these retailers to experience the risks resulting from WEC underestimation more acutely. While this is a legitimate commercial reality for some smaller retailers, we do not consider that this indicates, of itself, that a higher percentile better reflects efficient costs. We consider the efficient cost benchmark is intended to reflect the costs faced by a typical retailer employing prudent risk management practices, rather than the costs incurred by individual retailers facing particular scale or capital constraints. Raising the WEC percentile to accommodate all possible hedging constraints would effectively tie wholesale costs to the least efficient retailers in the market, rather than reflecting the efficient costs of a typical prudent retailer. We consider that the inclusion of a volatility allowance will help to mitigate the additional wholesale costs experienced by some smaller retailers, without raising the WEC above the efficient level.

Retailer submissions emphasised the 16% underestimation rate observed at the 50th percentile. However, this occurred alongside a far greater overestimation rate of 84%, with the average size of overestimations being larger than that of underestimations. This demonstrates that instances of underestimation at the 50th percentile are both infrequent and usually limited in scale. Therefore, we consider that the back-cast results do not indicate a material or systematic risk of under-recovery at the 50th percentile. In the minority of instances where the WEC is underestimated by the 50th percentile, the provision of the volatility allowance will mitigate under-recovery and associated risks.

We consider that the rate of underestimation in the back-cast analysis is mostly driven by the unprecedented volatility of mid-2022, which saw the spot market suspended for the first time in its history, and has since been adjusted for in subsequent iterations of the model. Modelling inputs, assumptions and, accordingly, results have adapted to reflect the possibility of the volatility observed in 2022, as evidenced by a 148% increase in the average load weighted spot price across all modelled percentile estimates between DMO 3 and DMO 5. The modelled hedging strategy was also recalibrated with increased cap contract volume to adapt to the increased frequency of spot prices above $300 per MWh. This further supports our position that the back-cast results do not indicate a deficiency in the 50th percentile estimate. Instead, the 16% underestimation rate reflects the occurrence of an exceptionally rare and unprecedented market event, which has influenced modelling assumptions since then.

We also acknowledge consumer groups' views that a WEC percentile below the 50th should be considered but note this would result in asymmetric allocation of risk to retailers, which would in turn create systemic risk of wholesale cost under-recovery. Such risk could be damaging to retail competition (as it may harm the viability of smaller retailers, contributing to market concentration), which we consider would not be in the long-term interests of consumers.

We note retailer concerns that a volatility allowance may not be sufficient to ameliorate instances of underestimation. While this may be true of individual instances of underestimation, the volatility allowance will apply regardless of whether an underestimation of the WEC actually occurs. The accumulation of a volatility allowance in all instances, alongside larger and more frequent instances of overestimation, should compensate retailers for rare instances of underestimation.

Sufficient hedging of spot price risk

We acknowledge some retailer concerns that a lower percentile estimate assumes less prudent hedging of spot price risk. However, this is not how the wholesale cost model functions in practice. The modelled hedging strategy is the same at all percentiles; accordingly, the risk of extreme spot prices is reflected regardless of the percentile estimate adopted.

The hedging strategy is selected algorithmically by identifying the strategy that results in the lowest variation in WEC estimates across the distribution of modelled spot price and demand outcomes. This hedging strategy is then settled against all spot price and demand simulations to create the final WEC distribution, from which the percentile estimate is selected. We consider that targeting minimum variation in the WEC distribution, rather than lowest average cost, prioritises protection against a range of price outcomes and is the best available mathematical proxy for prudence.

The process for selecting the hedging strategy invariably results in full or near full coverage of retailer seasonal peak load (and over-coverage at times when demand is below the seasonal peak), since under-coverage would increase exposure to extreme spot prices in some simulations and not others, which would increase variability in the WEC distribution. As a result, extreme spot prices are actually more common in the simulation associated with the

50th percentile than the 75th, because higher spot prices trigger greater payment from the modelled retailer's contract counterparties and reduce the WEC accordingly. Therefore, we consider that our assumed hedging strategy adequately reflects that of prudent retailer, while the adoption of the 50th percentile ensures that the efficient costs of employing a prudent hedging strategy are reflected in the DMO wholesale costs.

Mid-range spot price exposure resulting from the assumed hedging strategy

We acknowledge the concerns of some retailers that the simulated hedging strategy results in some exposure to mid-ranged spot prices, but do not consider there is any reason this should result in a higher percentile estimate or changes to other parts of the methodology.

The back-cast analysis included a detailed investigation of the implications of spot price exposure resulting from the hedging strategy. The analysis found that exposure occurred when demand was high enough to exceed base futures coverage, but the spot price was too low to trigger payment from the modelled retailer's strong cap coverage (which usually exceeded the retailer's maximum demand). This dynamic ensures that none of the modelled spot exposure is truly 'unhedged', since all exposure has an effective ceiling price of $300 per MWh.

We note the concerns of some retailers that in practice this could result in exposure to relatively high prices below the cap strike – for example, $299/MWh. However, the back-cast demonstrated that most exposure to the spot price occurred at prices between $50/MWh and $150/MWh. Accordingly, the exposure resulting from the modelled hedging strategy does not materially impact the WEC when back-cast against actual market outcomes. We consider that the back-cast analysis has sufficiently tested the hedging strategy against volatility, since the 3 most volatile spot price years in NEM history were included in the 5-year period analysed.

In response to Origin Energy's concern about a high modelled cap payout driving the hedging strategy's composition,[108] we note that the modelled cap payout for most simulations (and in some years all simulations) has been lower than actual market outcomes in all years except 2023–24. Therefore, we are satisfied that the cap payout remains reflective of outcomes observed in the market.

Calibration of the WEC alongside other cost stack elements

We acknowledge that, as pointed out by some retailers, the reduction of the WEC percentile estimate in this draft determination coincides with reductions in other parts of the DMO cost stack. We maintain the view that each cost stack component should be assessed independently, using the most accurate and appropriate method available for estimating that specific cost.

Publication of the WEC distribution

In response to GloBird Energy's request to publish the full WEC distribution amid concerns it may be skewed towards extreme outcomes, we note the results of all simulations including the full WEC distribution are published annually alongside both draft and final determinations. These published results show that the WEC distribution is broadly balanced.

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108 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 6.

Compensating consumers for volatility rather than retailers

We acknowledge the ECA's position that volatility has resulted in consumers paying above efficient wholesale costs and that, as such, a volatility allowance should accrue to consumers by being subtracted from the WEC. However, we note that prior DMO determinations were made under different regulations, which we considered were best met by adopting the 75th percentile. Under the Regulations, we consider that a volatility allowance accruing to consumers would be functionally equivalent to a lower percentile estimate. As discussed above, this would systematically allocate a greater portion of risk to retailers over the long term. This could jeopardise retailer viability, which would be against the long-term interests of consumers.

We also consider that the ECA's proposal to redistribute past forecast errors based on the results of the back-cast would effectively amount to a true-up mechanism based on backward looking estimates rather than costs incurred (which differ between retailers). We consider this would be problematic, given the purpose of a true-up mechanism is traditionally to replace estimates with actuals, not with an alternative estimate.

Incentives to effectively manage volatility

We acknowledge the JEC's view that a provision for volatility within the DMO price could weaken incentives for retailers to manage wholesale cost risks themselves. However, we consider this is unlikely to be true in practice. Retailers remain fully exposed to the difference between their actual wholesale costs and the DMO benchmark. Where a retailer can hedge more efficiently than assumed in the DMO modelling, this results in either higher margins or the ability to offer more competitive market offers and gain market share. Therefore, we do not consider that a volatility allowance disincentivises efficient hedging practices in any meaningful way.

4.3.3 Risk management costs arising from solar exports

We have continued to exclude solar exports from the interval meter dataset used to create blended load profiles for wholesale modelling. The load profiles have been based on a blended dataset of interval meter and accumulation meter data. The interval meter datasets have been published along with this draft determination.

4.3.4 New morning and evening peak contracts

We have not included the ASX's new morning and evening peak contracts in the modelled hedging strategy for this draft determination, given their lack of traded volume. This position was supported by most stakeholders who engaged on the topic.

We appreciate input from stakeholders on parameters we could use to determine whether these new products should be included in the hedging strategy for future determinations. We agree with stakeholders that liquidity, traded volumes and tradability are relevant factors for inclusion and will consider these as the market for these products develops.

4.3.5 Time of use WECs

We have decided to use the same method as the QCA for calculating time of use WECs for this draft determination. As discussed in the issues paper, this will involve dividing the load profile into specified time periods and calculating a ratio for each, based on the demand-weighted price for the individual period compared with the overall load profile. The WEC will then be scaled according to these ratios in each time of use period. This ensures that the resulting WECs reflect the varying cost of wholesale electricity throughout the day, while adding up to the flat rate WEC on a consumption-weighted basis. This approach aligns with recommendations of stakeholders, who considered the approach reasonable, transparent and adequately simple.

To calculate time of use WECs, we will divide the load profile according to the assumed time of use network tariff in all regions. We consider this approach avoids unnecessary complexity in determining usage charges for each time of use period.

We consider that utilising the same load profile used to determine the WEC, which includes interval meter data for each half-hourly period, is in accordance with 1st Energy's recommendation that sufficiently granular interval meter data be used to determine the time of use WECs. In accordance with EnergyAustralia's suggestion that detailed bottom-up information pertaining to each time of use period be published, the start and finish times for each time of use charging window are detailed in Appendix D. Time of use WECs for individual charging periods can be found in the cost assessment model published alongside this draft determination.

4.3.6 Other responses to stakeholder feedback

Embedded networks

We acknowledge submissions explaining that several aspects of our wholesale methodology would not be readily applicable to embedded networks. However, this is now not relevant because the DMO will not apply to embedded networks in DMO 8.

4.4 Wholesale energy costs

Wholesale energy costs are forecast to decrease across all DMO regions and customer types between the DMO 7 and DMO 8 periods, except for controlled load customers in Ausgrid and Endeavour Energy.

This has been driven by decreases in contract and spot market prices, but this was partly offset by a peakier load profile shape in SA Power Networks. The movements in base future and cap contract prices on an annualised and trade weighted basis are:

- for NSW – a decrease in base futures contract prices of $8.20/MWh and a decrease in cap contract prices of $4.20/MWh
- for Queensland – a decrease in base futures contract prices of $4.20/MWh and a decrease in cap contract prices of $4.30/MWh
- for South Australia – a decrease in base futures contract prices of $2.90/MWh and a decrease in cap contract prices of $4.40/MWh.

Having increased to high levels during 2024, contract prices declined steadily throughout most of 2025, before falling rapidly in late 2025 and into 2026. Coinciding with the rapid decline in contract prices, spot prices for the December quarter 2025 fell an average of 43% across the NEM compared with the previous quarter and 44% from the same time the previous year.[109] Spot prices above the cap strike of $300/MWh contributed $3/MWh to the

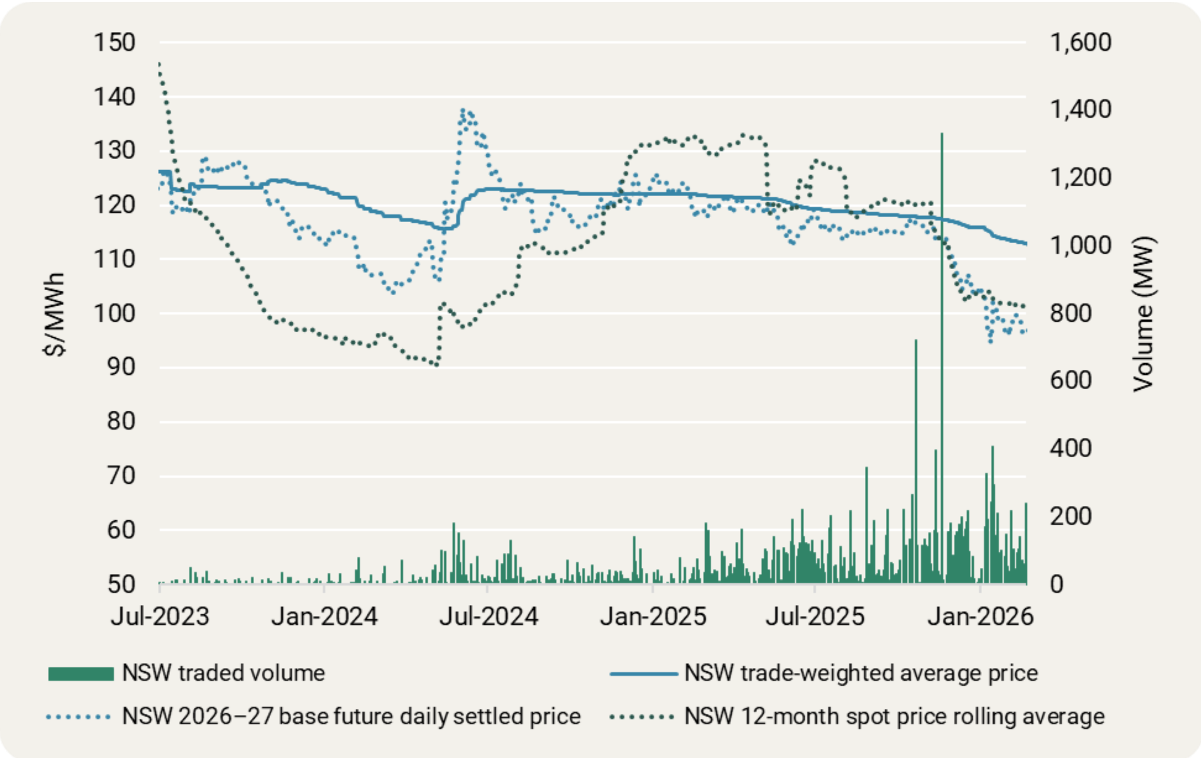
[109] AEMO, Quarterly Energy Dynamics – Q4 2025, Australian Energy Market Operator, January 2026, pp. 12–13.

average price, down 85% from the same time the previous year.[110] The reduction in prices and volatility has been driven by increased output from wind and battery generators, which along with fewer coal plant outages has reduced reliance on gas and hydro capacity during evening demand peaks.[111] Though some high spot price activity resumed in early 2026, prices have so far remained suppressed compared with historical averages.

Some contract prices have risen since the wholesale modelling for the draft determination was completed, coinciding with conflict in the Middle East (as show in the most recent data in Figure 4.7 to Figure 4.12). Accordingly, increases in contract prices since the conflict began are not yet reflected in the WECs used in this draft determination. Changes in contract prices will be captured in the WECs used in the final determination. At the time of writing, volume-weighted average contract prices in all regions remain lower than in DMO 7, despite the recent conflict-driven price increases.

For most regions, the largest volume of trade was observed in the latter half of 2025 and early 2026. This resulted in the falling contract prices at this time having greater impact on trade-weighted average prices than the higher prices throughout 2024. Queensland saw more traded volume during 2024 than other regions, resulting in the higher prices at that time having greater impact on its trade-weighted average.

Figure 4.7 NSW base future daily settled price and trade-weighted average, 2026–27

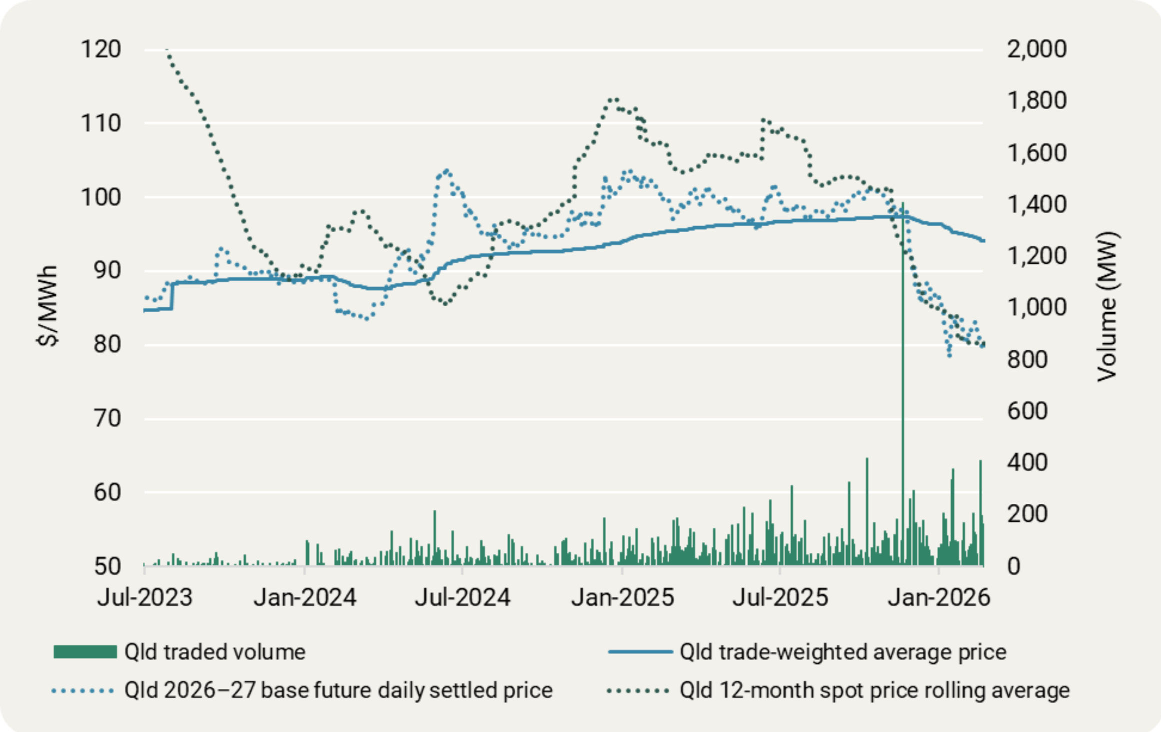


Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2026–27 financial year.
Source: AER analysis using ASX, AEMO data.

110 AEMO, Quarterly Energy Dynamics – Q4 2025, Australian Energy Market Operator, January 2026, p. 13.

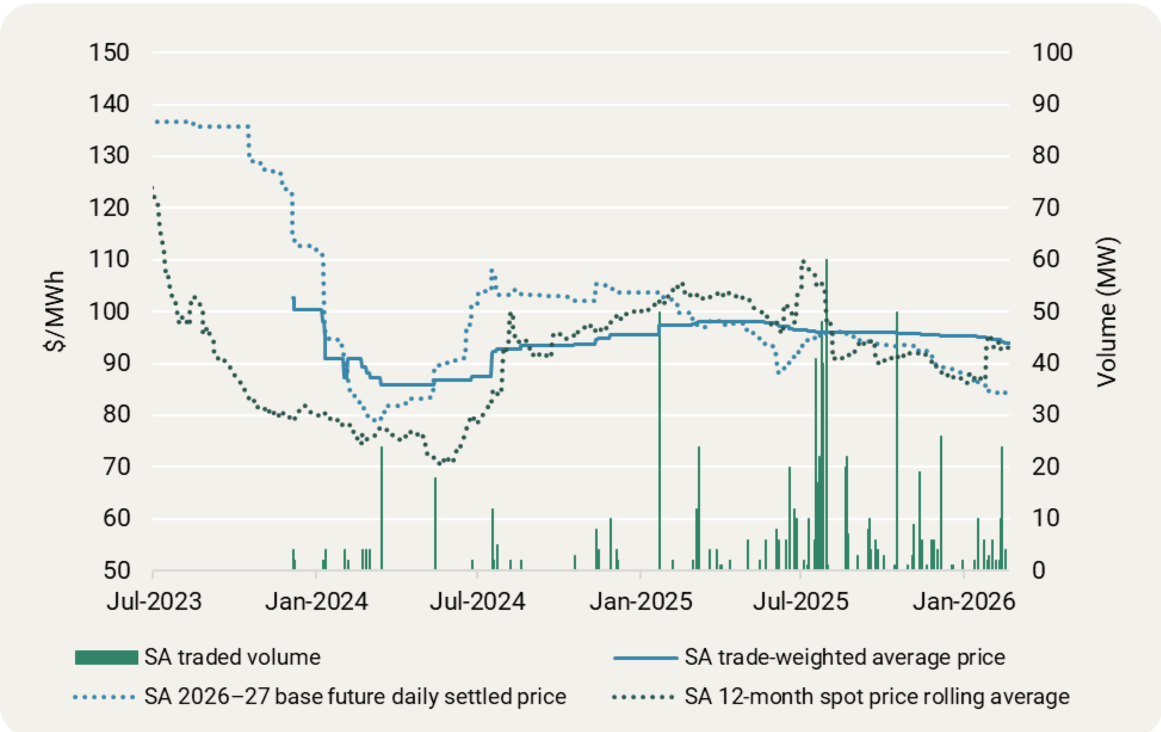
111 AEMO, Quarterly Energy Dynamics – Q4 2025, Australian Energy Market Operator, January 2026, p. 1.

Figure 4.8 Queensland base future daily settled price and trade-weighted average, 2026–27



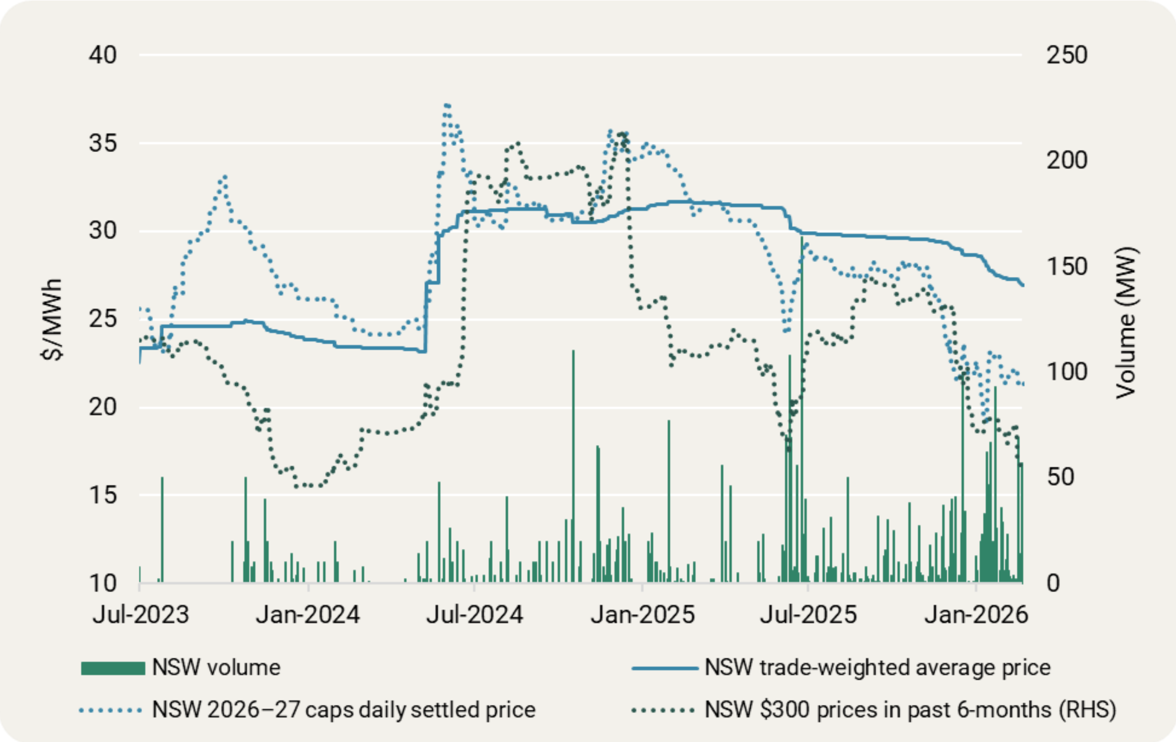
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2026–27 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 4.9 South Australia base future daily settled price and trade-weighted average, 2026–27



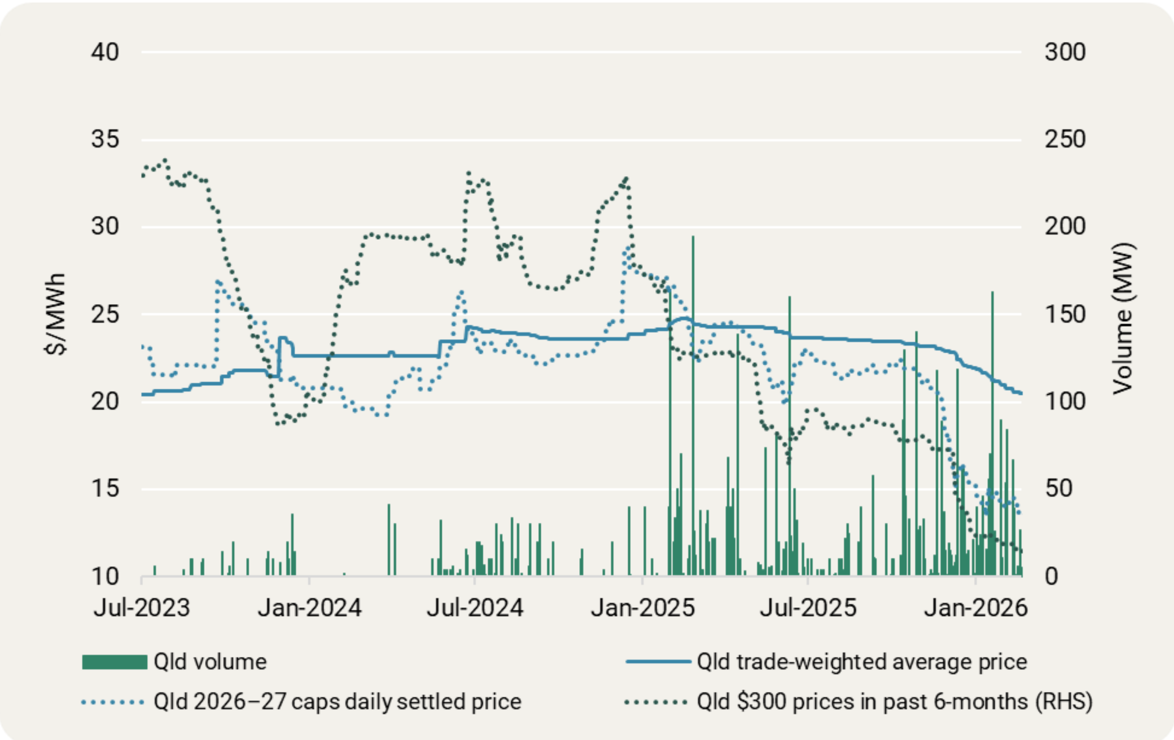
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2026–27 financial year. For South Australia, a trade-weighted average price was not available until early 2024 because volume had not been traded for all quarters prior to that time.
Source: AER analysis using ASX, AEMO data.

Figure 4.10 NSW cap daily settled price and trade-weighted average, 2026–27



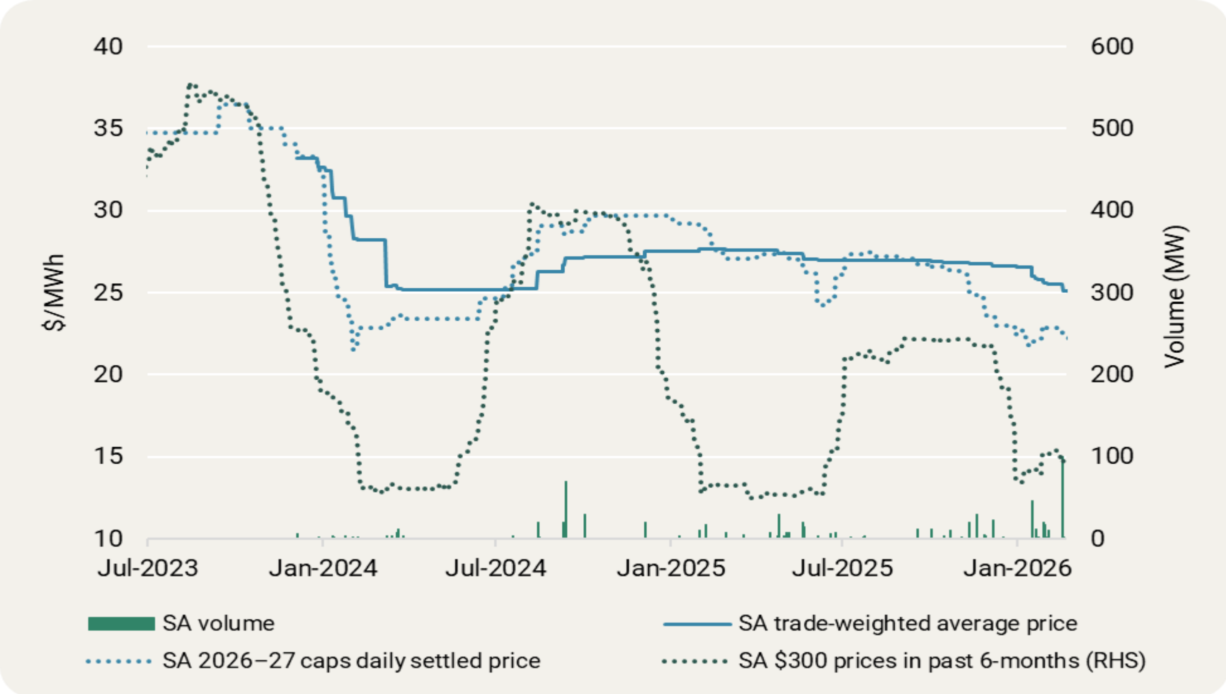
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2026–27 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 4.11 Queensland cap daily settled price and trade-weighted average, 2026–27



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2026–27 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 4.12 South Australia cap daily settled price and trade-weighted average, 2026–27



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2026–27 financial year. For South Australia, a trade-weighted average price was not available until early 2024, because volume had not been traded for all quarters prior to that time.
Source: AER analysis using ASX, AEMO data.

Smaller aspects of the wholesale cost changed little in NSW and Queensland, falling $0.08/MWh and $0.87/MWh, respectfully.

Other wholesale costs increased by $7.73/MWh in South Australia, driven by ancillary services and Reliability Emergency Reserve Trader (RERT) costs. Ancillary services was the largest driver of the increase, rising $6.58/MWh. This was primarily driven by Lower 1-second FCAS costs, for which the price rose above $5,000/MWh in 53 separate half-hourly intervals between 24 July and 17 August 2025, breaching the cumulative price threshold and triggering administered pricing.[112]

Table 4.1 Wholesale costs for 2026–27 DMO 7 draft determination, $/MWh (variable costs, ex. GST, nominal)

Distribution region	Customer type	2025–26 (final)	2026–27 (draft)	Change year-on-year
Ausgrid (NSW)	Flat rate	$172.20	$153.44	-10.9%
	CL1	$124.58	$125.93	1.1%
	CL2	$122.71	$131.32	7.0%

112 AER, Electricity prices above $5,000 per MWh – July to September 2025, Australian Energy Regulator, 1 December 2025, pp. 10–15.

Distribution region	Customer type	2025–26 (final)	2026–27 (draft)	Change year-on-year
Endeavour Energy (NSW)	Flat rate	$182.42	$164.66	-9.7%
	CL 1	$130.29	$118.90	-8.7%
	CL2	$130.29	$105.78	-18.8%
Essential Energy (NSW)	Flat rate	$175.54	$154.21	-12.2%
	CL1	$123.89	$125.14	1.0%
	CL2	$123.89	$125.14	1.0%
Energex (SE Queensland)	Flat rate	$164.39	$144.36	-12.2%
	CL1	$113.10	$107.32	-5.1%
	CL2	$119.95	$110.34	-8.0%
SA Power Networks (South Australia)	Flat rate	$191.72	$186.21	-2.9%
	CL1	$120.19	$98.65	-17.9%

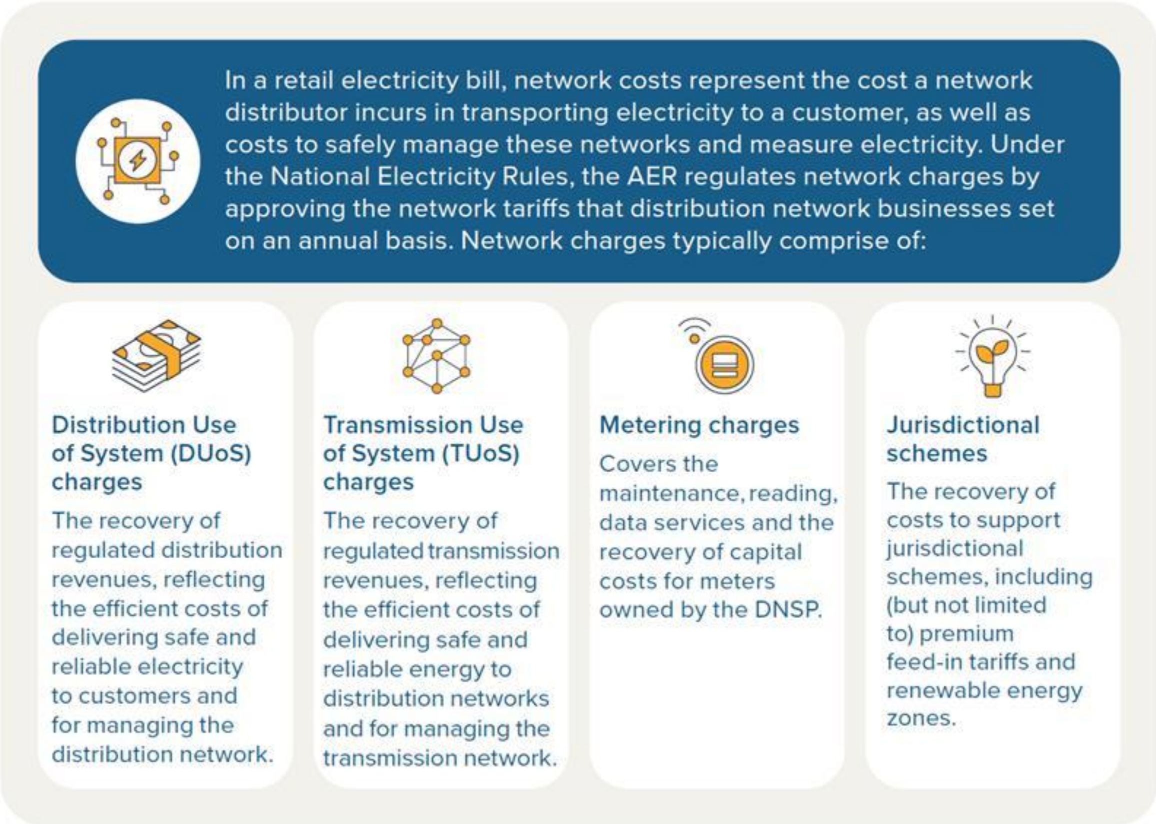
5 Network costs

For the DMO 8 draft determination we have decided to:

- apply the lowest applicable network tariff for the DMO flat rate retail tariff and comparison price because retailers can use either a flat rate or time of use network tariff for flat rate tariffs
- apply the time of use network tariffs for the DMO time of use retail tariff and comparison price, which allows retailers to recover network charges in the same manner they are incurred
- apply the default time of use network tariff in all regions except for Ausgrid where the most common time of use network tariff will apply
- apply the time of use network tariff for the comparison price set for non-regulated tariffs because these tariffs are likely to require a smart meter and be subject to a cost-reflective network tariff.

Changes in network costs range from decreases of 20.3% to increases of 10.1% since DMO 7. Network costs represent between 38.7% and 48.1% of the DMO 8 draft determination prices.

The Regulations direct the AER to have regard to network costs when determining the DMO.[113]



113 Regulations s 16(4)(c)(ii).

5.1 Issues paper

In previous DMOs, we were required to set annual prices for 3 customer types (residential with controlled load, residential without controlled load, and small business customers). In determining these annual prices, we calculated annual network costs by applying the assumed annual usage to the flat rate network tariff. However, the issues paper noted that for DMO 8, the Regulations require the AER to determine:

- DMO tariff caps for a range of regulated tariffs, including flat rate and time of use retail tariffs[114]
- an annual comparison price for non-regulated tariffs.[115]

The issues paper sought stakeholder views on whether it is more appropriate to develop blended network tariffs or instead assign the respective network tariff to the corresponding DMO tariff cap (for example, a time of use network tariff would be used to determine a time of use retail tariff). The issues paper also asked which network tariff should be used in Essential Energy and SA Power Networks, because there are multiple time of use network tariffs in these networks.

In setting the annual comparison price for non-regulated tariffs, we need to determine annual network costs, either by applying a particular network tariff or blending network tariffs. The issues paper sought stakeholder feedback on the approach for network costs in the comparison price for non-regulated tariffs.

The issues paper also discussed the AEMC accelerating smart meter deployment rule change, which will see a progressive installation of smart meters with a target of 100% installation rates by 2030.[116] Typically, when a smart meter is installed, the customer is transferred onto a time of use network tariff (or other cost-reflective network tariff). However, as set out in our issues paper, the rule change will allow customers with smart meter installations to choose to remain on flat rate retail offers for up to 2 years after the installation, despite the network tariff for this customer being a time of use tariff. This results in a mismatch between network and retail tariffs for the proportion of customers that stay on a flat rate retail offer.

Given this mismatch, the issues paper sought stakeholder feedback on whether to continue with flat rate network tariffs or instead develop blended network tariffs.

5.2 Stakeholder views

5.2.1 Blended network tariffs

The majority of retailers and consumer groups opposed blended tariffs.

114 Regulations, s5 and s16(1A).

115 Regulations, s16(1).

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

Of the 16 submissions that put forward views on blending, 13 supported using the network tariff that corresponds with the form of the DMO tariff to determine network costs.[117] That is, use a time of use network tariff for a time of use DMO and a flat network tariff for a flat DMO. 1st Energy, AGL, Alinta Energy, Energy Trade, SA Power Networks and the AEC discussed the complexity and instability caused by blending network tariffs to derive the network cost component.[118] Some retailers were concerned that blending network tariffs would inevitably result in cross-subsidies[119] and that blending network costs would risk obscuring price signals, producing arbitrary outcomes that are misaligned with actual cost drivers.[120] The ECA supported the use of corresponding network tariffs because it helps ensure retailers are not over or under-recovering network charges.[121]

AGL acknowledged the potential mismatch in network and retail tariffs arising from the smart meter rule change but considered it is not clear if the mismatch is material enough to blend network tariffs.[122] For AGL, this change in methodology would only be warranted once the customer data reflects an issue.

ENGIE also supported using the network tariff corresponding to the form of the DMO tariff, but considered that the AEMC rule change will require retailers to absorb costs due to under-recovery of network costs in instances of retail and network tariff misalignment.[123] ENGIE made the further point that the DMO should explicitly account for this risk retailers are exposed to because of tariff misalignment elsewhere in the methodology.[124]

5.2.2 Appropriate network tariff to apply to the DMO tariff

Eight stakeholders commented on what the most appropriate corresponding network tariff would be when network tariffs are not blended and the approach when there is more than one time of use tariff available, which occurs in Essential Energy and SA Power Networks.

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117 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 3; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 3; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 2; Energy Trade, Submission to DMO 8 issues paper, 27 November 2025, pp. 1–2; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 2; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 6; AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 3–4; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 11–12; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5; SA Power Networks, Submission to DMO 8 issues paper, 26 November 2025, p. 1; Ausgrid, Submission to DMO 8 issues paper, 1 December 2025, pp. 1–2; AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, pp. 1–2; ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 8.

118 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 2; AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 3–4; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5; Energy Trade, Submission to DMO 8 issues paper, 27 November 2025, pp. 1–2; SA Power Networks, Submission to DMO 8 issues paper, 26 November 2025, p. 1; AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, pp. 1–2.

119 Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5.

120 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 2.

121 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 8.

122 AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 3–4.

123 ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 3.

124 ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 3.

EnergyAustralia and AGL considered the default time of use network tariff set by the DNSPs in the Tariff Structure Statements to be the most appropriate choice.[125] In Essential Energy, where the most common residential tariff (tariff code BLNT3AL) has more than double the number of customers compared with the default, AGL noted that the tariff is now closed to new customers. To maintain ongoing cost alignment, it recommended aligning the DMO time of use tariff structure with the default tariff structure.[126]

ActewAGL and Alinta Energy supported the adoption of the most commonly available network tariff for Essential Energy and SA Power Networks.[127]

ENGIE preferred combining time of use tariffs where there is more than one relevant time of use network tariff, which could be based on the proportion of customers on each tariff.[128] ActewAGL suggested that further consideration could be given to a methodology that blended these network tariffs.[129] The ECA also recommended deriving network costs under a blended network cost approach and the most common network tariff, and adopting the approach that is least cost to consumers.[130]

The JEC also commented on which approach to be taken, but the submission did not provide a recommendation for instances where the most prevalent network tariff is not the default.[131]

5.2.3 Network costs to include in the comparison price for non-regulated tariffs

Of the 10 stakeholders who commented on whether to blend network costs for the comparison price, the majority (7) supported using a single network tariff when calculating the comparison price.[132] ActewAGL, ENGIE, EnergyAustralia, AGL, Alinta Energy and the JEC supported a flat rate network tariff.

The ECA and Origin Energy recommended establishing separate reference bills for each of the flat DMO and time of use DMO.[133] However, EnergyAustralia considered that introducing multiple comparison prices within the same region would introduce complexity, with potential

125 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 7; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 4.

126 AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 4.

127 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 4; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 6.

128 ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 4.

129 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 4.

130 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 9.

131 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 10.

132 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 9; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 4; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 6; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 3; ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 3; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 2.

133 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 12; ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 8–9.

confusion for customers and retailers about which comparison price to use when comparing different tariff types.[134]

The ECA suggested that the AER should further analyse the results of using flat rate and time of use network prices and then simply choose the 'smaller' one.[135] In the case that 2 substantially different prices result, the ECA then suggested a blended approach.

The JEC did not see a need to have a retail price reflect the network tariff. Therefore, it preferred the continued use of a flat rate network tariff for all DMOs.[136] The JEC recommended the AER further assess various options, with priority being given to the lowest cost outcomes for consumers.

Only one retailer, GloBird Energy, supported a blended network cost for the comparison price because it believe it is more representative of how consumers will be using energy.[137]

5.3 Draft determination

5.3.1 Draft determination is to use the lowest cost network tariffs

The AER will apply a particular network tariff to determine DMO 8 tariff caps and comparison prices, rather than blend multiple network tariffs. We observe most stakeholders were against blending network tariffs and instead favoured applying the corresponding network tariff to the DMO tariffs. We agree with stakeholders that applying a particular network tariff promotes transparency and predictability, in addition to avoiding limitations encountered in the data under a blending approach.

For determining the DMO flat rate tariffs and comparison prices, we observe either the flat rate or time of use network tariffs could apply. As noted above, the smart meter roll out will see customers increasingly assigned to a time of use network tariff, although they may remain on a flat rate retail tariff. Our draft determination applies the lowest cost of either the flat rate or time of use network tariff, which ensures consumers do not pay more than efficient costs. It also prevents retailers from keeping these savings in additional margin, which could occur if the DMO was instead set at the rate of the more expensive network tariff.

This provides an incentive for retailers to have the lowest cost applicable network tariffs assigned. In some regions this will be the time of use network tariff, which becomes applicable once a smart meter is installed. We acknowledge that not all customers in DMO regions currently have smart meters installed. However, retailers can arrange for installations and are required to do this for all small customers by 2030.

As set out below, in the Essential Energy, Energex and SA Power Networks regions, the time of use network costs are lower than the flat rate network costs. Our draft determination is to use the time of use network tariffs in the DMO flat rate tariff cap and comparison price. In

134 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 6.

135 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 8–9.

136 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 8–9.

137 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 2.

Ausgrid and Endeavour Energy, the time of use network costs are higher and consequently the flat rate network costs will apply in the DMO flat rate tariff cap and comparison price.

For determining the DMO time of use tariffs and comparison prices, we apply the underlying prices and structure of the applicable time of use network tariffs, which allows retailers to recover network charges in the same manner they are incurred. We note the AER role in approving network tariff design through the revenue determination process is based on the tariffs reflecting the costs to networks of serving their customers.[138] The time of use tariff designs and prices of network tariffs send signals about when it is efficient to use the network and reduce the need for additional investment in network infrastructure.

Passing through the time of use network tariff signals also produces time-varying ‘flexible’ retail tariffs, which are the retail tariff caps and comparison prices the AER must determine under the Regulations, in addition to determining a flat rate tariff cap.

Our draft determination applies the applicable default time of use network tariff in all regions except Ausgrid where the most common time of use network tariff will apply. Ausgrid’s default time of use network tariff is a demand tariff and, under the Regulations, a time of use DMO retail tariff cannot include demand charges.

We consider our draft determination approach is consistent with the mandatory consideration of efficient costs to supply customers and the requirement to have regard to network costs when determining the DMO comparison prices and tariff caps. For the flat rate DMO tariffs, we also consider this approach is broadly consistent with the JEC and the ECA submissions advocating for the DMO to allow recovery of the network costs that result in the lowest costs for consumers. Our approach to network costs for the DMO will allow retailers to recover the costs of the lowest applicable network tariff. Table 5.1 demonstrates the price differences for flat rate and time of use tariffs across DNSPs and residential and small business customers.

Ausgrid and Endeavour Energy

In the case of Ausgrid and Endeavour Energy, where the flat rate network tariff has a lower annual cost than the time of use:

- the DMO flat rate tariff and comparison price will include recovery of the flat rate network tariff
- the DMO time of use tariff and comparison price will include recovery of the time of use network tariff.

We consider this appropriate because in Ausgrid’s network, retailers cannot assign a time of use retail customer to a flat rate network tariff once a smart meter is installed.

In Endeavour Energy, customers remain on the flat rate network tariff for 12 months after a smart meter is installed.[139] If a customer chooses to move to a time of use retail tariff, there is a small risk of the retailer over-recovering from the customer because the retailer continues to be charged the flat rate network costs for 12 months. This over-recovery does not occur if

[138] This is done through the approval of the DNSPs’ Tariff Structure Statements.

[139] Unless the customer has initiated the smart meter installation, which causes the time of use network tariff to apply immediately.

a customer instead choses to remain on the flat rate retail tariff, because the flat rate retail tariff includes the recovery of the flat rate network tariff.

We consider this risk of over-recovery is small, given the limited time window available, and that it also depends on the customer proactively providing explicit informed consent to move to a time of use standing offer within that limited time window. We consider it more likely that these customers would elect to move onto a market offer (time of use or otherwise), which is likely to be lower priced than the time of use and flat rate standing offer tariff caps.

5.3.2 Approach when multiple time of use network tariffs apply

In instances where multiple time of use network tariffs are available (Essential Energy and SA Power Networks), a single time of use network tariff needs to be selected as the basis for calculating network costs for the time of use DMO tariff.

We consider the most appropriate approach for DMO 8 is applying the default time of use network tariff, as set out in the Tariff Structure Statements, in Endeavour Energy, Essential Energy, Energex and SA Power Networks. The default network tariff is the most common in most regions, except for Essential Energy.

In Essential Energy, the default network tariff is not the most common. However, in the coming years Essential Energy's default network tariff will become the most common because all customers receiving smart meters under the AEMC accelerated smart meter rollout will be assigned to the default time of use network tariff in the first instance. There is a relatively immaterial price difference of 1% between the default and most common network tariffs.

In Ausgrid, the current default network tariff is a demand tariff and, for residential customers, it is the most common. Under the Regulations[140] a time of use DMO retail tariff cannot include demand charges. Accordingly, we consider Ausgrid's most common time of use network tariffs for residential and small business are the most appropriate tariffs for DMO 8.

Our draft determination preserves seasonality structures when passing through network tariffs in the DMO time of use tariffs.

5.3.3 Annual comparison price for non-regulated tariffs

Our draft determination applies the time of use network tariff for non-regulated tariff comparison prices. We consider this will reflect the efficient costs retailers will incur when supplying these offers, because non-regulated tariffs are likely to require a smart meter and be subject to a cost-reflective (that is non-flat rate) network tariff.

For a non-regulated standing offer to comply with the DMO, the annual price of the non-regulated standing offer must not exceed the comparison price. For these standing offers, retailers will be free to set the daily supply, usage charges and other tariff components at any level as long as the annual price complies with the DMO.

[140] Regulations, s. 5.

For Essential Energy, Energex and SA Power Networks, as the flat rate and time of use prices are equivalent, this also means that the comparison price for the non-regulated tariff, flat rate, time of use and SSO will be equivalent.

5.3.4 Drivers for changes in costs since DMO 7

While we are applying new network tariffs for DMO 8, we observe that unlike other components of the DMO cost stack, network prices are generally increasing when compared on a like-for-like basis (that is, year-on-year movements in corresponding flat rate and time of use network tariffs). We observe that the main drivers for changes in the forecast network tariffs for 2026–27 provided by distributors in February 2026 compared with DMO 7 network costs are:

- Increases in network costs for all DMO DNSPs reflect the price paths and approved expenditure set out in our respective revenue determinations. These revenue determinations were made for NSW DNSPs in 2024 and for Queensland and South Australian DNSPs in 2025. In all DMO regions, a key driver of the price paths was market factors (higher actual inflation and interest rates) causing a higher return on capital. Our determinations also included expenditure in important emerging areas such as improved network resilience to address climate change-related risks, the uptake and integration of consumer energy resources and cyber security. In making our revenue determinations, we assess these expenditure proposals to ensure consumers pay no more than necessary for a safe and reliable power supply.
- There are also some specific factors for each region contributing to the network cost aspect of the DMO price in 2026–27:
  - In NSW, the NSW Roadmap cost and transmission costs have increased (noting transmission costs will be finalised for the final determination). However, an increase in forecast energy consumption has partially offset price increases for Ausgrid and Endeavour Energy customers.
  - In SE Queensland, transmission costs have increased (to be finalised for the final determination) and there are a number of both proposed and approved cost pass-throughs for extreme weather events, which are contributing to increased costs.
  - In South Australia, our revenue determination also included important expenditure to improve the management of safety risks. New transmission costs, including for the Firm Energy Reliability Mechanism Scheme costs and the impact the new transmission loop between South Australia, Victoria and NSW will have on interregional settlement residues, are also starting to flow through. Our draft includes estimates of these costs, which will be finalised for the final determination. For residential customers, there is an overall forecast decrease in residential consumption due to higher levels of consumer energy resources.

However, the actual network costs included in DMO 8 have decreased since DMO 7 by 1.3% to 20.3% in Essential Energy, Energex and SA Power Networks, depending on customer type (except for SA Power Networks residential, which has increased 3.8%). This is because these tariff caps and comparison prices include recovery of the time of use network tariff, which is both lower than the 2026–27 flat rate network tariff and 2025–26 flat rate network tariff used in DMO 7. In Ausgrid and Endeavour Energy, network costs have increased by 3.6% to 10.1% as both the 2026–27 (DMO 8) flat rate and time of use network tariffs are higher than the 2025–26 flat rate network tariff used in DMO 7.

5.3.5 Summary

The network tariffs that are used to assess network costs for each DNSP as well as annual network costs are set out in Table 5.1.

We are seeking stakeholder feedback on this approach to determining network costs and if any adjustments should be considered for the DMO 8 final determination.

Table 5.1 AER estimates for 2026–27 network costs (including GST)

Region	Customer type	Network tariff	2026–27 $
Ausgrid	Residential flat rate	Residential flat EA010	$743.09
	Residential time of use	Residential TOU EA025	$754.24
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	Controlled load 1 EA030	$67.30
		Controlled load 2 EA040	$113.65
	Small business flat rate	Small Business flat EA050	$1,992.84
	Small business time of use	Small Business TOU EA225	$2,109.22
	Small business non-regulated tariff		
Endeavour	Residential flat rate	Residential flat N70	$910.76
	Residential time of use	Residential STOU N71	$916.11
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	Controlled load 1 N50	$131.81
		Controlled load 2 N54	$170.40
	Small business flat rate	General Supply Block N90	$1,731.92
	Small business time of use	General Supply STOU N91	$1,759.12
	Small business non-regulated tariff		
Essential	Residential flat rate	LV Residential TOU Sun Soaker BLNRSS2	$1,191.33
	Residential time of use		

Region	Customer type	Network tariff	2026–27 $
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	LV Controlled Load 1 BLNC1AU	$100.43
		LV Controlled Load 2 BLNC2AU	$143.07
	Small business flat rate	LV Small Business TOU Sun Soaker BLNBSS1	$2,358.68
	Small business time of use		
	Small business non-regulated tariff		
Energex	Residential flat rate	Residential TOU Energy 6900	$746.35
	Residential time of use		
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	Controlled Load 1 (Super Economy) 9000	$51.41
		Controlled Load 2 (Economy) 9100	$51.41
	Small business flat rate	Small Business TOU Energy 6800	$1,486.17
	Small business time of use		
	Small business non-regulated tariff		
SA Power Networks	Residential flat rate	Residential Time of Use RTOU	$930.67
	Residential time of use		
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	Residential Single Rate RSR (controlled load)	$149.40
		Residential TOU controlled load	$169.88
	Small business flat rate	Small Business Time of Use SBTOU	$1,897.99
	Small business time of use		
	Small business non-regulated tariff		

6 Environmental costs

For the DMO 8 draft determination, we have retained our existing market-based approach to environmental cost forecasting.

Environmental costs make up between 2% and 3% of the DMO 8 draft prices.

Environmental costs have decreased since DMO 7 across all distribution regions, customer types and tariff structures by between 30% and 36%, representing decreases of between $15 and $26 for residential customers and between $38 and $65 for small business customers, depending on the region.

6.1 Issues paper

In our issues paper we proposed to maintain our market-based approach to calculating environmental costs. The paper noted that the Regulations require us to consider the cost of compliance with state and Commonwealth laws, while the Regulations additionally require us to consider the efficient costs to supply customers. We considered that the previous approach remains reasonable under the Regulations.

6.2 Stakeholder views

Most stakeholder submissions to our issues paper did not raise issues with our established approach to calculating environmental costs.

Origin Energy supported our market-based approach to calculating environmental costs[141] and 1st Energy agreed that most environmental scheme costs are variable and should remain in the usage component.[142] Additionally, SACOSS considered that the proposed DMO objective gives the AER scope to examine the recovery of environmental costs in future determinations.[143]

6.3 Draft determination

The DMO 8 draft determination retains our existing market-based approach to environmental cost forecasting.

6.3.1 Environmental cost inputs

The environmental cost inputs for 2026–27 are shown in Table 6.1, together with inputs used for 2025–26 for comparison.

Decreases in costs are largely due to lower Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) costs in all regions. LRET costs have decreased due to large decreases in large-scale generation certificate prices.[144] SRES costs

141 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 12.

142 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 2.

143 SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, p. 7.

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

have decreased because retailers are required to surrender fewer small-scale technology certificates than in DMO 7.[145]

Decreases in jurisdictional scheme costs further contributed to the decreases in South Australia.[146]

Table 6.1 Environmental costs for 2025–26 and 2026–27 (ex. GST, nominal)

DMO region	2025–26 $/MWh	2026–27 $/MWh	Change year-on-year (%)
Ausgrid	$15.93	$11.23	-29.5%
Endeavour Energy	$16.22	$11.43	-29.5%
Essential Energy	$15.84	$11.17	-29.5%
Energex	$11.92	$8.40	-29.5%
SA Power Networks	$16.42	$10.53	-35.9%

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

146 In South Australia, 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).

7 Retail costs

For the DMO 8 draft determination, we have decided to:

- maintain the customer-weighted average approach for retail costs to serve and other costs because it provides an efficient benchmark and reflects the revealed costs of most retailers operating in a competitive environment
- apply the standing offer customer-weighted average for 'modest' costs to acquire and retain customers to recognise that most standing offer customers are predominantly served by larger retailers and that these customers are likely to benefit from a subset of these acquisition activities
- apply the customer-weighted average to quantify both the smart meter allowance and the cost of capital allowance to cover the projected shortfall in the smart meter allowance, since it continues to be a suitable indicator for efficient costs
- quantify bad debt based on actual written-off bad debt expenses, to more accurately reflect these costs to retailers
- allocate bad debt as a fixed cost component of the DMO – however, we are seeking feedback on whether bad debt should be a fixed or variable cost component that scales with usage for the DMO 8 final determination.

Retail costs represent approximately 7% to 16% of the total DMO price for flat rate residential and small business customers and have decreased by 2% to 16% since DMO 7, depending on the DMO region.

The Regulations direct us to have regard to the costs, including retail costs, of supplying small customers with an essential service.[147]

Retail costs reflect a range of costs incurred by a retailer, including costs to serve, the costs associated with acquiring and retaining new customers, bad debt and smart meter costs. For DMO 8, we have considered the actual costs incurred by 24 retailers that sell to approximately 98.9% of residential and 98.1% of small business customers in DMO regions.[148]

To establish a benchmark for retailer costs, we must have regard to the efficient costs of supplying electricity for small customers on standing offers, the types of small customers on standing offers and the long-term interest of consumers. These new mandatory considerations guided how we quantified all retail cost subcomponents based on the retailer cost data, including efficient benchmarks for costs to serve, as well as the modest costs of acquiring and retaining small customers on standing offers.[149]

147 Regulations ss. 9A and 16(4).

148 Proportions are based on Q3 2024–25 retail performance data.

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

7.1 Issues paper

7.1.1 Cost to serve

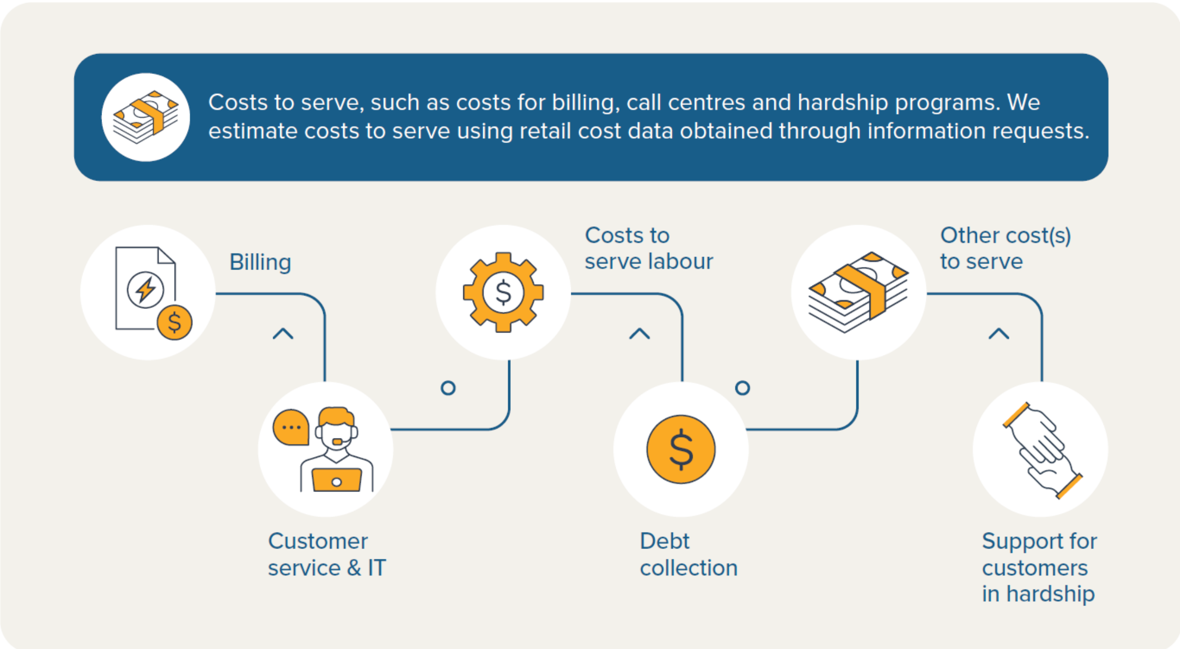
The DMO 8 issues paper consulted on options for quantifying costs to serve to reflect the new mandatory considerations as described above.

The issues paper discussed that, in DMOs 6 and 7, we adopted a customer-weighted average across all retailers' cost data to quantify the costs to serve residential and small business customers in each DMO region. The issues paper sought stakeholder feedback on 2 options to quantify retailers' efficient costs to serve under the Regulations:

- **Option 1:** Apply a standing offer customer-weighted average across all retailers.
- **Option 2:** Maintain the customer-weighted average approach.

Significant outliers are excluded from the retailer cost dataset to determine the average in both options.

Retailer costs to serve include the following sub-components:



While the Regulations repealed the previous mandatory consideration of retailer costs to serve,[150] we have had regard to costs to serve as forming part of the efficient costs to supplying electricity.[151] To exclude these costs could result in a DMO price that is not viable for most retailers because retailers must carry out these activities but would be unable to recover these costs. It is also not in the long-term interests of consumers if retailers are unable to achieve an efficient margin – this could lead to retailer exit and diminished retail competition. These retailer activities are fundamental to supplying electricity. As a result, we consider including an efficient allowance to recover these costs in the DMO price is consistent with the DMO objective of providing consumers with a fair, trusted and reasonably

150 Old Regulations, s. 16(4)(c)(v). See also, Explanatory statement, item 43.

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

priced electricity option that reflects the costs of supplying small customers with an essential service, and is in the long-term interests of consumers.[152]

7.1.2 Costs to acquire and retain customers

The issues paper consulted on the approach used to quantify the modest costs to acquire and retain customers. The issues paper explained that, while a customer-weighted average was previously applied to the costs to acquire and retain customers of all retailers, this approach was undertaken within the context of the old Regulations. As a result, it may not be appropriate to apply the same methodology to determine modest costs to acquire and retain customers under the Regulations.

The issues paper also noted the guidelines in the government's DMO outcomes paper in determining the appropriate level of costs to acquire and retain customers. Specifically, it 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
- 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.

As such, the issues paper sought stakeholder feedback on 2 options for determining modest customer acquisition and retention costs under the Regulations:

- **Option 1:** Apply a standing offer customer-weighted average across all retailers, excluding significant outliers from the retailer cost dataset.
- **Option 2:** Adopt the Essential Services Commission's (ESC) historic benchmarking approach, using an inflation adjusted NEM-wide benchmark from 2013–14.

Retailer costs to acquire and retain customers include the following sub-components:

152 Regulations, ss. 9A and 16(4)(ba).

7.1.3 Bad debt

The issues paper outlined that we must have regard to bad debt costs to achieve the DMO objective of a fair, trusted and reasonable price.[153]

The issues paper flagged that the definition of bad debt has been updated to represent the amount of accounts receivable that retailers have identified and written off as being uncollectable. Therefore, such debt is no longer based on provisions in retailer accounts.

The issues paper consulted on 3 options for expressing bad debt costs in setting the DMO price:

- **Option 1:** Allocate bad debt as a fixed cost component of the DMO.
- **Option 2:** Allocate bad debt as a variable cost component of the DMO.
- **Option 3:** Allocate bad debt as a combination of fixed and variable cost components of the DMO.

7.1.4 Smart meter costs

In the issues paper, we stated that we would maintain our approach and use a cost of capital allowance to cover the projected shortfall in the smart meter allowance to recognise that additional smart meters will be installed.

For DMO 8, we incorporated the smart meter data into our formal retailer cost information request. Collecting both datasets through a single request ensures the costs are mutually exclusive and reduces the risk of double counting. As a result, the smart meter dataset has expanded from 11 retailers in DMO 7 to 24 retailers in DMO 8.

7.2 Stakeholder views

7.2.1 Cost to serve

Many stakeholders, including 1st Energy, ActewAGL, the AEC, GloBird Energy, AGL, Origin Energy and Alinta Energy, supported option 2 – maintaining the customer-weighted average approach.[154] Origin Energy noted that a customer-weighted average across all retailers provides a more representative benchmark of efficient costs because it considers economies of scale and promotes incentives for retailers to meet the cost benchmark.[155] Similarly, AGL noted that the AER should focus on deriving costs for a broadly representative retailer when determining efficient costs to supply and meeting the DMO objective of a fair and reasonable price.[156]

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

154 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp 4–5; ActewAGL, Submission to DMO 8 Issues Paper, 26 November 2025, p. 5; AGL, Submission to DMO 8 Issues Paper, 1 December 2025, pp. 8–9; Alinta Energy, Submission to DMO 8 Issues Paper, 28 November 2025, p. 7; GloBird Energy, Submission to DMO 8 Issues Paper, 26 November 2025, p. 4; Origin Energy, Submission to DMO 8 Issues Paper, 1 December 2025, p. 7.

155 Origin Energy, Submission to DMO 8 Issues Paper, 1 December 2025, p. 7.

156 AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 8–9.

EnergyAustralia and Origin Energy cautioned that there is little difference between the costs of serving standing offer and market offer customers.[157] These retailers noted that core retail activities, such as billing, customer service, metering coordination and collections processes, are largely identical across both customer groups. EnergyAustralia submitted that efficient costs should be based on prudent, actual costs.[158] This view was also expressed by both small and large retailers through our workshops and bilateral meetings.

Consumer groups, including the ECA and the JEC, supported adopting option 1 – the standing offer customer-weighted average approach.[159] The ECA and the JEC considered this option to better reflect the efficient costs of supplying standing offer customers. The ECA noted that standing offer customers are predominantly served by the largest retailers. As a result, they face limited competitive pressure, meaning they are less likely to experience the benefits of retail competition, such as lower prices or enhanced service options.[160] The JEC considered that applying a standing offer weighted approach aligns more closely with the mandatory consideration of efficient costs to supply standing offer customers under the proposed reforms.[161]

ENGIE did not support either approach because both methods risk skewing cost estimates towards retailers with large customer bases and cost advantages.[162] It contended that using cost estimates that are reflective of larger retailers would make it difficult for smaller retailers to recover efficient costs.

7.2.2 Costs to acquire and retain customers

Stakeholders had mixed views on the appropriate treatment of customer acquisition and retention costs in the DMO.

ActewAGL, GloBird Energy, Powershop, 1st Energy, EnergyAustralia, AGL and Origin Energy did not prefer either option proposed in DMO 8 issues paper. Instead, they proposed maintaining the existing customer-weighted average approach.[163] They considered this methodology provides a broad and representative benchmark of costs to acquire and retain customers across the retail market, including small and mid-sized retailers.

ActewAGL noted that the total costs to acquire and retain customers would not change regardless of the AER's estimation method, but if less costs are recovered from standing offer customers, more costs would need to be recovered from market offer customers.[164]

157 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 9; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 7.

158 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 9.

159 ECA, Submission to DMO 8 Issues Paper, Energy Consumers Australia, 26 November 2025, pp. 11–12; JEC, Submission to DMO Issues Paper, Justice and Equity Centre, 1 December 2025, p. 13.

160 ECA, Submission to DMO 8 Issues Paper, Energy Consumers Australia, 26 November 2025, pp. 11–12.

161 JEC, Submission to DMO Issues Paper, Justice and Equity Centre, 1 December 2025, p. 13.

162 ENGIE, Submission to DMO 8 Issues Paper, 26 November 2025, pp. 6–7.

163 1st Energy, Submission to DMO 8 Issues Paper, 28 November 2025, pp. 4–5; ActewAGL, Submission to DMO 8 Issues Paper, 26 November 2025, p. 6; AGL, Submission to DMO 8 Issues Paper, 1 December 2025, p. 9; EnergyAustralia, Submission to DMO 8 Issues Paper, 28 November 2025, p. 9; GloBird Energy, Submission to DMO 8 Issues Paper, 26 November 2025, p. 4; Origin Energy, Submission to DMO 8 Issues Paper, 1 December 2025, pp. 7–8; Powershop, Submission to DMO 8 Issues Paper, 28 November 2025, p. 2.

164 ActewAGL, Submission to DMO 8 Issues Paper, 26 November 2025, p. 6.

Powershop stressed that consumers on standing offers have the same exposure to acquisition and retention activity as market offer customers, and both options would favour larger retailers.[165]

Some retailers suggested the AER should define ‘modest’ costs to acquire and retain customers. EnergyAustralia viewed modest costs to acquire and retain customers as the minimum prudent spend needed to ensure standing offer customers can understand their options, interact with their retailer and access clear, comparable information.[166] 1st Energy suggested that modest should be interpreted as a measured, evidence-based allowance that recognises necessary onboarding and ongoing service costs but excludes excessive marketing or promotional spending.[167] Origin Energy stressed that, without providing any clear definitions, any determination will be subjective.[168]

The AEC raised concerns that both proposed options would be insufficient, potentially imposing material impacts on smaller retailers and, by extension, reducing competition in the market.[169] It noted that smaller retailers play a critical role in driving competitive pressure by targeting disengaged customers of larger incumbent retailers and argued that, for these participants to compete effectively, they must be able to recover customer acquisition costs and earn a reasonable return. The AEC urged the AER to consider the potential competitive impacts of the proposed approaches when setting the costs to acquire and retain customers at a reasonable level.

ENGIE and Alinta Energy supported the standing offer customer-weighted average approach because it better reflects the efficient costs of supplying standing offer customers.[170] Alinta Energy considered this approach preferable to the ESC’s benchmarking method, despite being skewed towards larger retailers, because it is more reflective of current market conditions.[171] ENGIE similarly stated that the AER should calculate an allowance for customer acquisition and retention costs that reflects the efficient costs that most retailers are likely to incur.[172] While ENGIE considered option 1 to be more reflective of efficient costs than option 2, it reiterated broader concerns about the suitability of customer-weighted approaches and their ability to accurately capture efficient cost benchmarks.

Several consumer groups, including the AER’s Customer Consultative Group, the JEC and the ECA, submitted that customer acquisition and retention costs should be excluded entirely from the DMO.[173] The ECA considered that acquisition and retention costs do not benefit standing offer customers and that, based on the Regulations, the requirement for the AER to ‘take into account’ customer acquisition and retention costs is not the same as a requirement

165 Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 2.

166 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 9.

167 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, pp 4–5.

168 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp 7–8.

169 AEC, Submission to DMO 8 Issues Paper, Australian Energy Council, 26 November 2025, p. 3.

170 Alinta Energy, Submission to DMO 8 Issues Paper, 28 November 2025, p. 7; ENGIE, Submission to DMO 8 Issues Paper, 26 November 2025, p. 7.

171 Alinta Energy, Submission to DMO 8 Issues Paper, 28 November 2025, p. 7.

172 ENGIE, Submission to DMO 8 Issues Paper, 26 November 2025, p. 7.

173 Customer Consultative Group, Submission to DMO 8 issues paper, 19 November 2025, p. 9; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 13–14; ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp 12–13.

to include these costs.[174] Accordingly, the ECA recommended that zero costs to acquire and retain customers should be explicitly considered by the AER.[175] However, of the options presented, the ECA preferred the approach that results in the lower cost of acquisition estimate – the ESC's approach (option 2).[176]

The JEC considered there are various reasons why acquisition and retention costs should not be an explicit allowance in the DMO. It considered that these costs are already accounted for in the retail margin. Retailers can forego the margin and reinvest in business growth or augmentation activities.[177] The JEC also contended that general retail practice is to recover the costs of loss-leading offers from other customers with higher margin offers.[178] The JEC considered it is difficult to justify acquisition and retention costs as an additional cost that can be recovered from each customer. Finally, it stated that the assumption that consumers can shop around is no longer valid, particularly for those on standing offers.[179]

The Customer Consultative Group submitted that modest costs of acquisition and retention should represent essential service-related costs only, not the full costs, and should be guided by what is fair and reasonable for consumers.[180]

The South Australian Department for Energy and Mining supported adopting the ESC's approach to ensure customer acquisition and retention costs remain 'modest', noting that this aligns with the government's aim of keeping these costs modest.[181]

7.2.3 Bad debt

Several retailers supported allocating bad debt as a fixed cost component of the DMO. ENGIE, EnergyAustralia, AGL and Alinta Energy considered this approach to be simple, transparent and consistent with previous DMO determinations and the approach adopted by other regulators.[182] Consumer groups, including the ECA, the JEC and SACOSS, also supported allocating bad debt as a fixed cost component.[183] They considered this approach preferable due to concerns that variable recovery mechanisms could disproportionately impact customers experiencing vulnerability.

EnergyAustralia noted that bad debt can arise regardless of consumption levels because bad debt is more related to the number of customers served and the costs associated with billing,

174 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 12–13.

175 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 12–13.

176 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 12–13.

177 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp 13–14.

178 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp 13–14.

179 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp 13–14.

180 Customer Consultative Group, Submission to DMO 8 issues paper, 19 November 2025, p. 9.

181 South Australian Department for Energy and Mining, Submission to DMO 8 issues paper, 12 December 2025, p. 2.

182 AGL, Submission to DMO 8 Issues Paper, 1 December 2025, p. 9; Alinta Energy, Submission to DMO 8 Issues Paper, 28 November 2025, p. 8; ENGIE, Submission to DMO 8 Issues Paper, 26 November 2025, p. 7.

183 ECA, Submission to DMO 8 Issues Paper, Energy Consumers Australia, 26 November 2025, p. 13; JEC, Submission to DMO Issues Paper, Justice and Equity Centre, 1 December 2025, p. 14; SACOSS, Submission to DMO Issues Paper, South Australian Council of Social Service, 1 December 2025, p. 10.

account management and collections.[184] AGL noted that there is not a strong basis for moving to a variable or hybrid approach because it considered there is no strong correlation between bad debt and consumption.[185] Alinta Energy raised concerns that allocating bad debt on a variable basis would require customers with higher use to fund a disproportionate share of these costs.[186]

Powershop supported allocating bad debt to the variable component, considering that bad debt is proportional to customer bill sizes, after allowing for government concessions and rebates.[187] It stated that, while a fixed-cost allocation is simpler to implement in practice, it is regressive. ActewAGL, GloBird Energy, Energy Trade and 1st Energy supported a hybrid approach that splits bad debt across fixed and variable components, arguing that this could result in a more accurate recovery of bad debt costs.[188] These retailers suggested that any split should be evidence-based and reflect the overall revenue contribution of fixed and variable charges.

Origin Energy questioned relying solely on written-off debt, noting that provisioning practices smooth year-to-year fluctuations in bad debt and may better reflect longer-term cost trends. Origin Energy considered that incorporating provisioning information could improve the stability and accuracy of bad debt estimates. [189]

7.2.4 Smart meter costs

Two stakeholders provided feedback on smart meter costs.

Origin Energy supported the approach of using historic installation data until the legacy meter retirement plans are in place, due to the significant costs retailers incur to install smart meters.[190] Furthermore, it agreed that using a working capital allowance is necessary to recover the shortfall in projected meter installations. This is due to the significant increase in forecast installations following the AEMC’s accelerated smart meter rule change.

The JEC submitted that smart meter costs should not be included until there is transparency around the smart meter costs themselves and the extent that they are offset and recovered by retailers.[191] It argued that if retailers recovered these costs from customers, offset these costs through the sale of services to metering providers or engaged in other activity that impacted metering costs for the retailer, these amounts are accounted for fully. The JEC considers that cost recovery is likely so there is no case for explicitly including metering costs.[192]

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184 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 10.

185 AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 9.

186 Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 8.

187 Powershop, Submission to DMO 8 Issues Paper, 28 November 2025, pp. 2–3.

188 1st Energy, Submission to DMO 8 Issues Paper, 28 November 2025, p. 5; ActewAGL, Submission to DMO 8 Issues Paper, 26 November 2025, p. 6; Energy Trade, Submission to DMO 8 Issues Paper, 27 November 2025, p. 2; GloBird Energy, Submission to DMO 8 Issues Paper, 26 November 2025, p. 4.

189 Origin Energy, Submission to DMO 8 Issues Paper, 1 December 2025, p. 8.

190 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 8.

191 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp 12–13.

192 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp 12–13.

7.3 Draft determination

7.3.1 Costs to serve and other costs

For the DMO 8 draft determination, we have decided to maintain the customer-weighted average approach (option 2) to quantify the efficient costs to serve and other costs. This approach is also applied to 'other' retail costs since it represents another sub-component of the total retail cost stack, and the Regulations require the AER to consider the efficient costs of supplying standing offer customers.

This approach reflects the revealed costs reported by retailers (excluding outliers) operating in competitive markets, which we consider to be a suitable indicator of efficient costs. It has been our view in previous DMOs that this approach of taking a customers weighted average after excluding outliers ensures inefficient retail costs are not captured. As such, we will continue with this approach because efficient costs is one of the policy considerations we must have regard to under 16(4)(a) of the Regulations. The benchmark also captures the costs of most retailers supplying electricity to small customers in DMO regions, not just a subset of them. Although not a determinative factor, it also maintains regulatory consistency with prior DMO determinations, as well as with approaches adopted by other regulators, including the ESC, in setting efficient retail costs for the Victorian Default Offer (VDO).

We acknowledge retailer submissions that costs to serve customers are generally not differentiated between market and standing offer customers. Core cost to serve functions, including billing, labour and customer service, are typically not structured differently by offer type. In this context, we consider that applying the customer-weighted average remains an appropriate method for estimating the efficient costs to serve for standing offer customers.

This approach is consistent with promoting the long-term interests of consumers. By establishing an efficient benchmark cost to serve based on this approach, it provides appropriate incentives for retailers to operate efficiently and to meet this benchmark over time. This includes smaller retailers, some of whom incur larger costs to serve relative to the larger incumbents. The continuity of this approach from previous DMO determinations provides for methodological stability.

7.3.2 Costs to acquire and retain customers

For the DMO 8 draft determination, we have decided to apply the standing offer customer-weighted average approach (option 1) to quantify the modest costs to acquire and retain customers. Since Tier 1 retailers have the largest proportion of standing offer customers, these results are skewed towards their costs to acquire and retain customers, which is relatively more modest than the customer-weighted average approach.

For the reasons set out below, we consider it is appropriate that modest acquisition and retention costs are a lower amount than the efficient benchmark for costs to acquire and retain customers.

Standing offer customers may benefit from acquisition and retention activities

A lower 'modest' amount for standing offer customers is appropriate because it reflects that standing offer customers may only directly benefit from a subset of all acquisition and retention activities. For example, retailers will incur some costs in managing the relationship with standing offer customers but some of these costs may be incurred in enhancing consumer experience, some onboarding costs for standing offer customers and ongoing costs related to customer service.[193]

Standing offer customers also benefit from acquisition and marketing activities, which is driven by competition in the retail market. For instance, some acquisition and retention related activities, such as advertising latest offerings, incentives and product features, do encourage disengaged standing offer customers to switch to market offers. The Q1 2025–26 retail performance reporting data found that approximately 3.0% of small customers on standing offers switched to a market offer across all DMO regions.[194] Standing offer customers also benefit from the presence of retailer competition because it drives efficiency, which brings overall costs down. Some smaller retailers incur relatively higher acquisition and retention costs relative to their larger incumbents,[195] so the complete removal of costs to acquire and retention may harm the competitive viability of these retailers.

We acknowledge the ECA and JEC's concerns that costs to acquire and retain customers should not be included in the DMO cost stack because they do not directly benefit standing offer customers. However, for the reasons above, we consider these costs do directly benefit standing offer customers and it is appropriate for the DMO to include some level of customer acquisition and retention costs.

Determining modest acquisition and retention costs

The Explanatory Statement accompanying the Regulations states that modest costs are intended to mean those costs associated with customer acquisition and retention incurred by retailers in supplying standing offer customers. For example, it would exclude costs associated with marketing purposes of innovation, because these are not costs associated with supplying standing offer customers.[196]

We consider that it is challenging and perhaps unrealistic to derive accurate costs incurred specifically for acquisition and retention costs for standing offer customers across a financial year because:

- retailers have noted in workshops and submissions that they are unable to separately identify acquisition and retention costs for market and standing offer customers, and that advertising campaigns are not specifically targeted at market offer customers
- customers can shift from market to standing offers and standing to market many times – retailers noted in workshops that a customer could have been on a market offer leading to acquisition and retention expenses before moving to a standing offer, and consumer groups noted that anyone can be a standing offer customer at any time for a variety of reasons.[197]

We have decided to take a standing offer customer-weighted average to determine modest acquisition and retention costs. This approach is consistent with the ESC's interpretation of

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193 DCCEEW, Review Outcomes: 2025 reforms to the Default Market Offer, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 27.

194 AER, Retail market performance update, Quarter 1 2025–26, Australian Energy Regulator.

195 AER, DMO 8 issues paper, Australian Energy Regulator, 5 November 2025, p. 38.

196 Explanatory statement accompanying the Regulations, p. 17.

197 Customer Consultative Group, Submission to DMO 8 issues paper, 19 November 2025, p. 5.

'modest', which intentionally sets acquisition and retention costs in the VDO lower than customer-weighted average acquisition costs of retailers.

Given that this approach weights each retailer's reported acquisition and retention costs by their share of standing offer customers, this is more likely to reflect the modest acquisition spend for standing offer customers, compared with the customer-weighted average approach that is applied to all customers.

Tier 1 retailers supply approximately 71% of standing and market offer customers in DMO regions. This share increases to 82% when considering only standing offer customers.[198] Due to established economies of scale, Tier 1 retailers have lower per-customer acquisition and retention costs than many other retailers. This means that applying the standing offer weighted average gives greater weight to the lower acquisition and retention costs reported by Tier 1 retailers, resulting in a lower estimate for customer acquisition and retention costs than a weighted average based on each retailer's share of both standing and market offer customers. We consider this approach is more appropriate than applying a customer-weighted average because it better reflects the modest level of acquisition and retention costs for standing offer customers.

We acknowledge the JEC's assertion that the retail margin should already account for retailers' costs to acquire and retain customers.[199] However, as outlined in previous DMO determinations, we do not agree that it follows that costs to acquire and retain customers should not be explicitly accounted for in the DMO and instead be included in the retail margins.[200] Our (as well as the ESC and Frontier Economics') analysis of Earnings Before Interest, Tax, Depreciation and Amortisation (EBITDA) margins already accounts for costs retailers incur to acquire and retain customers.[201] These average EBITDA margins are calculated once acquisition and retention costs are subtracted from earnings. Were we to derive margins under a different conceptualisation that included recovery of acquisition and retention costs, the acquisition and retention costs would not be subtracted from earnings and the resulting percentages in margins considered would be greater.

Relative to the customer-weighted average approach, the standing offer customer-weighted average costs to acquire and retain customers reflects a modest allowance because it results in between a $9.81 and $14.60 reduction in DMO prices for residential customers and between an $8.36 and $13.15 reduction for small businesses (ex. GST).[202]

This approach allows us to determine separate acquisition and retention costs by customer type and region, which ensures that any cross-subsidies for cost recovery are removed.

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198 AER, Retail market performance update, Quarter 1 2025–26, Australian Energy Regulator.

199 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp 13–14.

200 AER, DMO 7 final determination, Australian Energy Regulator, 26 May 2025, pp 62–63.

201 ESC, Victorian Default Offer 2025-26, Essential Services Commission, 21 May 2025, pp. 58-60; Frontier Economics, Final Report Retail Electricity Price Investigation 2024-27, 21 November 2023, pp. 63-64.

202 Refer to Table 7.1 for values for costs to acquire and retain customers under the standing offer customer-weighted average approach.

We also consider our approach better reflects the requirements of the Regulations that the AER have regard to the costs of standing offer customers,[203] whereas the ESC is required to have regard to the costs of both standing and market offer customers.

Our values are comparable to the ESC benchmark of $47.83 per customer in the 2026–27 Draft Decision paper for the VDO. For instance, under the standing customer-weighted average approach, our values range between $6.97 less and $6.58 more than ESC’s value of modest acquisition and retention costs (ex. GST), but do exhibit customer type and regional variation.

7.3.3 Retail and other costs

Table 7.1 provides a breakdown of our draft determination for DMO 8 of retail and other cost components, by customer type and DMO region.

Table 7.1 Retail and other costs ($/customer), by DMO region, excluding GST

Cost category	NSW	SE Queensland	South Australia
Residential customers, flat rate and time of use			
Costs to serve	$94.86	$88.54	$95.88
Costs to acquire and retain	$50.90	$40.86	$46.76
Other costs	$19.87	$17.77	$21.61
Total	**$165.63**	**$147.17**	**$164.26**
Small businesses, flat rate and time of use			
Costs to serve	$119.27	$104.97	$101.23
Costs to acquire and retain	$54.41	$51.24	$51.73
Other costs	$41.53	$28.40	$25.97
Total	**$215.21**	**$184.62**	**$178.93**

Source: AER analysis of retailer cost information.

Figure 7.1 illustrates the year-on-year changes in retail and other costs over time.

Relative to DMO 7, retail and other costs have declined between $18.85 and $34.81 for residential customers and between $8.58 and $37.25 for small businesses, depending on DMO region (ex. GST). This reduction is largely driven by lower reported retailer costs across most retail cost sub-components, including retailers’ costs to serve and costs to acquire and retain customers.

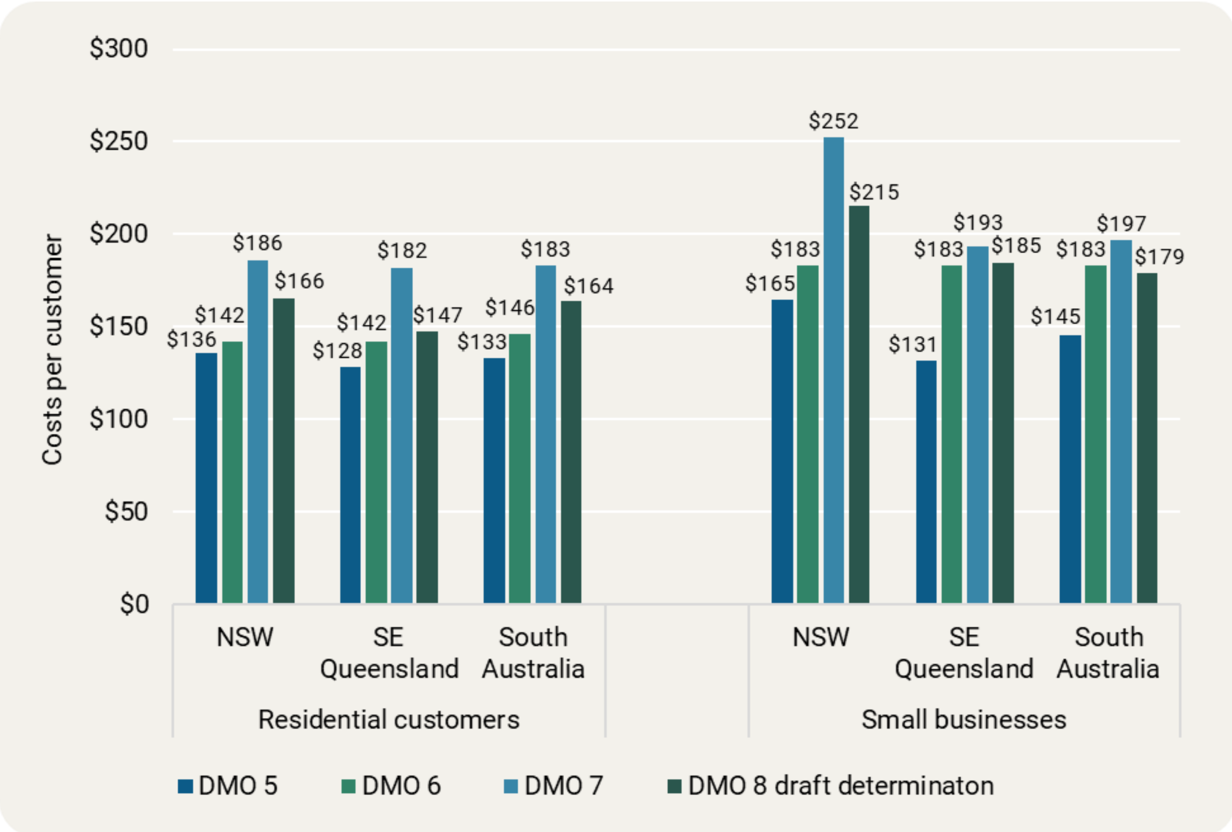
For instance, DMO 8 retail and other costs would still be lower relative to DMO 7 costs across all DMO regions and both customer types (determined under the old Regulations) if we maintained the customer-weighted average approach to quantify the costs to acquire and retain customers. That is, relative to DMO 7, DMO 8 retail costs for residential customers

203 Regulations, s. 16(4)(iv).

would have declined between $4.24 and $25.00 and retail costs for small businesses would have declined between $0.21 and $27.03, depending on DMO region (ex. GST).

For DMO 8 we sought further clarification from retailers to verify data inputs, such as determining whether specific retail cost components should be included in the retail cost stack. For instance, to avoid double counting, we have excluded costs that should already be accounted for elsewhere in the DMO cost stack (such as network and wholesale costs) and costs relating to fines and penalties.

Figure 7.1 Time series of retail and other costs ($/customer) by DMO region and customer type, excluding GST



Source: AER analysis of retailer cost information.

7.3.4 Bad debt

For the DMO 8 draft determination, we have applied the customer-weighted average to quantify bad debt and have allocated bad debt as a fixed cost component of the DMO. We consider this an appropriate determination of efficient costs for this component.

We acknowledge Origin Energy's concerns about only using written-off debt because provisioned amounts would smooth year-to-year fluctuations in bad debt and may better reflect longer-term cost trends. In previous DMO determinations, we included provisions to account for risks for under-provisioning of bad and doubtful debt risk. However, we consider that using the actual expensed written-off debt allows retailers the full (albeit lagged) recovery of bad debt risk for future DMOs. In addition, using written-off debt amounts would protect consumers from over-recovery of bad debt and prevent retailers under-recovering bad debt, both of which inherently arise in forecasting.

Small business bad debt

We consider that retailing to small business customers presents a greater risk of bad debt because a proportion of small businesses fail, leaving retailers with unpaid bills and no or limited ability to recover debts once a business is wound-up/liquidated. The amount of bad debt may vary from year to year, because drivers of bad debt include macroeconomic factors that are difficult to predict. Residential customers present a lower bad debt risk due to smaller bills and outstanding debt, and the role of government support that assists residential customers to pay bills.

DMO 8 includes separate residential and small business allowances for recovery of actual bad debt written off by retailers. We consider that using written-off bad debt would avoid the risk of under-provisioning bad debt for retailers and avoid exposure to over-recovery of bad debt for consumers.

Full recovery of actual written-off bad debt was not guaranteed in DMO 7 or earlier because these DMOs used customer-weighted average provisioning, which included the risk of underestimating small business bad debt.

Using historical written-off debt data provided by retailers, we found that the written-off dollar-per-customer figures are lower for all customer types and regions than the bad and doubtful debt figures we used in past DMOs. For instance, for residential customers, the 2023–24 written-off bad debt is between $4 and $13 (ex. GST) lower than DMO 7 bad and doubtful debt figures. For small businesses, 2023–24 written-off bad debt is between $9 and $33 (ex. GST) lower than DMO 7 bad and doubtful debt figures.

DMO 7 and DMO 8 bad debt values

Table 7.2 shows the year-on-year change in bad debt. For residential customers, there was a minor increase in NSW, a reduction of $6.50 per customer in Energex and an increase of $7.36 per customer in SA Power Networks. For small businesses, there were declines across all DMO regions, but this was minimal in SA Power Networks.

Table 7.2 Bad debt ($/customer), excluding GST

DMO region	DMO 7 Bad and doubtful debt provisioning	DMO 8 Draft Determination Actual bad debt written off	Change ($)
Residential customers, flat rate and time of use			
Ausgrid	$35.53	$36.04	+$0.51
Endeavour Energy	$35.53	$36.04	+$0.51
Essential Energy	$35.53	$36.04	+$0.51
Energex	$35.45	$28.95	-$6.50
SA Power Networks	$39.64	$47.00	+$7.36
Small businesses, flat rate and time of use			
Ausgrid	$80.49	$72.80	-$7.68

DMO region	DMO 7 Bad and doubtful debt provisioning	DMO 8 Draft Determination Actual bad debt written off	Change ($)
Endeavour Energy	$80.49	$72.80	-$7.68
Essential Energy	$80.49	$72.80	-$7.68
Energex	$55.10	$40.58	-$14.51
SA Power Networks	$45.81	$44.86	-$0.95

Source: AER analysis of retailer cost information.

7.3.5 Smart meter costs

For the DMO 8 draft determination, we have decided to maintain the customer-weighted average to quantify smart meter costs. These smart meter costs were derived from our retail cost dataset comprising of 24 retailers, which we consider to be a broad and representative sample.

Our previous approach of taking the customer-weighted average revealed costs reported by retailers operating in competitive markets under the old Regulations is still applicable in the Regulations. We consider this approach establishes a benchmark for efficient costs, including smart meter costs, which was consistent with the prior DMO objective to allow retailers to recover their efficient costs.

Similar to our approach used to quantify costs to serve and other costs, we consider the customer-weighted average (excluding outliers) results in an efficient benchmark for smart meter costs. That is, it reflects the revealed costs of most retailers operating in competitive markets, which we consider to be a suitable indicator of efficient costs.

Given the accelerated rollout of smart meters across DMO regions, smart meter installations – and therefore costs – are expected to increase across the DMO period. Since retailers have only provided smart meter costs and installations as at 30 June 2025 per our retail cost information request, the smart meter allowance would have been underestimated in the DMO 8 price. Therefore, like previous DMO determinations, we have continued to include a cost of capital allowance to cover the projected average shortfall in the smart meter costs across the DMO 8 period. This was computed by using the projected number of installations reported by retailers at the midpoint of DMO 8 (31 December 2026) to cover that projected shortfall in the smart meter allowance.

We acknowledge the JEC's comments that these smart meter costs should not be included in the DMO until there is transparency of the cost themselves. In our most recent retail cost data collection for DMO 8, we requested that retailers provide a breakdown of the drivers of smart meter costs to improve transparency in the retail cost information request. However, most retailers indicated that they do not have visibility of this data because most smart meter costs are incurred as a combined service charge from third party metering providers.

We consider smart meter costs to be a type of retail cost that retailers incur that should be included in the calculation of a DMO price, particularly under the context of the mandatory smart meter rollout.

Table 7.3 provides a breakdown of the smart meter costs for the DMO 8 draft determination. Appendix B sets out a detailed breakdown of smart meter costs.

Table 7.3 Average smart meter costs, excluding GST

DMO region	Average annual cost per smart meter	Average annual cost per customer
Residential customers, flat rate and time of use		
Ausgrid	$118.52	$50.41
Endeavour Energy	$123.30	$79.29
Essential Energy	$118.68	$70.66
Energex	$108.28	$59.00
SA Power Networks	$110.03	$61.66
Small businesses, flat rate and time of use		
Ausgrid	$140.53	$39.69
Endeavour Energy	$137.49	$68.70
Essential Energy	$141.05	$63.53
Energex	$130.07	$61.30
SA Power Networks	$119.25	$61.61

Source: AER analysis of retailer cost information.

7.3.6 Summary of retail costs

Table 7.4 and Table 7.5 provide a breakdown of retail costs for residential customers and small businesses, respectively. Given that the retail cost data we have collected relates to the 2024–25 period, we have applied RBA forecast inflation for 2025–26 and 2026–27 to retain the value of these costs in real terms across the DMO 8 period.

Overall, retail costs declined primarily due to lower reported costs from retailers across several cost components, including retail and other costs (costs to serve, costs to acquire and retain customers, and other costs). Other factors that contributed to this decline were the change in methodology to quantify modest costs to acquire and retain customers and the use of actual bad debt written-off reported by retailers in the 2024–25 retail cost information request, instead of bad and doubtful debt that includes provisioning. The decline in retail costs is partially offset by increases in smart meter costs, which reflects the greater uptake of smart meters.

Table 7.4 Retail costs, residential customers flat rate and time of use, excluding GST

Region	Retail and other costs	Smart meter costs	Bad debt costs	Forecast CPI adjustment	Total	Difference to DMO 7 (%)
Ausgrid	$165.63	$50.41	$36.04	$18.20	$270.28	-4.9%
Endeavour Energy	$165.63	$79.29	$36.04	$20.29	$301.24	-3.8%
Essential Energy	$165.63	$70.66	$36.04	$19.67	$291.99	-6.6%
Energex	$147.17	$59.00	$28.95	$16.98	$252.10	-15.5%
SA Power Networks	$164.26	$61.66	$47.00	$19.71	$292.63	-3.8%

Table 7.5 Retail costs, small businesses flat rate and time of use, excluding GST

Region	Retail and other costs	Smart meter costs	Bad debt costs	Forecast CPI adjustment	Total	Difference to DMO 7 (%)
Ausgrid	$215.21	$39.69	$72.80	$23.67	$351.36	-8.4%
Endeavour Energy	$215.21	$68.70	$72.80	$25.76	$382.47	-7.0%
Essential Energy	$215.21	$63.53	$72.80	$25.39	$376.93	-9.5%
Energex	$184.62	$61.30	$40.58	$20.69	$307.19	-6.3%
SA Power Networks	$178.93	$61.61	$44.86	$20.61	$306.01	-2.4%

8 Retail margin

For the DMO 8 draft determination, we have decided to:

- maintain the retail margin as a percentage of total DMO costs due to its simplicity
- apply a uniform 6% retail margin for both residential and small business customers because the additional risks of retailing to small businesses are already accounted for elsewhere in the DMO cost stack.

Relative to DMO 7, in dollar terms, retail margins have decreased between $1.86 and $13.52 for flat rate and time of use residential customers, and between $247.67 and $390.32 for flat rate and time of use small business customers.

The Regulations now direct us to consider the efficient costs to supply electricity to small customers on standing offers,[204] inclusive of retail margins, when determining the standing offer price.[205]

While explicit reference to retailers making a reasonable profit has been removed from the Regulations, we consider retail margins are still an essential part of the DMO. We are also required to have regard to the long-term interest of consumers.[206] These new mandatory considerations have guided us in determining the quantum of efficient margins for the DMO 8 draft determination.

The Explanatory Statement and DMO outcomes paper set out the legislative intention to exclude a competition allowance in the DMO.[207]

8.1 Issues paper

8.1.1 Quantifying efficient margins

The issues paper consulted on approaches to determine the quantum of efficient retail margins.[208] The issues paper noted that efficient retail margins could be assessed from the following sources:

- retailers' average EBITDA margins using their reported 2024–25 retailer cost data
- retail margins inferred from the ACCC's customer-weighted average annual prices based on the 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

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

205 Explanatory statement accompanying the Regulations, p. 17.

206 Regulations, s. 16(4)(ba).

207 Explanatory Statement accompanying the Regulations, p. 2. DCCEEW, Review Outcomes: 2025 reforms to the Default Market Offer, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 8.

208 AER, DMO 8 issues paper, Australian Energy Regulator, 5 November 2025, pp. 43–48.

- Frontier Economics' expected returns approach, as considered by the Independent Competition and Regulatory Commission (ICRC) in their 2024–27 determination[209] and by the ESC in its VDO determinations.[210]

The issues paper also considered lowering small business retail margins to align with how other regulators set margins based on efficient costs, including the ESC, ICRC and OTTER.[211] These regulators set uniform retail margins across both residential and small business customer types. The issues paper explained that efficient margins may be lower than the 11% reasonable margin used in prior DMOs since written-off bad debt allowances would account for additional small business bad debt risk.

8.1.2 Form of retail margins

The Regulations require the AER to determine regulated tariff caps that an electricity retailer may charge small customers.[212]

Under this tariff-based pricing structure, the issues paper consulted on expressing the retail margin as either a fixed percentage across the total DMO cost base or as a hybrid across both fixed dollar and a percentage of variable costs.

The percentage-based approach was applied across total DMO costs in DMOs 6 and 7, whereas the hybrid approach, used by other regulators like OTTER and ICRC, applies a combination of fixed CPI-indexed dollar amount and a varying percentage component.

8.2 Stakeholder views

8.2.1 Quantifying efficient retail margins

AGL noted that the conclusions and recommendations stemming from Frontier Economics' report should be interpreted with caution.[213] It advised that instead of simply considering the range of margins, the AER should reference the most relevant economic and market parameters that support a particular margin scenario (low, base and high margin scenarios reported by Frontier Economics).[214]

EnergyAustralia noted that while EBITDA and market benchmarks can inform retailers' margins, they should not be treated as strict determinants in deciding the quantum of margins.[215] Origin Energy referenced the previous ACCC Inquiry into the NEM reports, noting that EBITDA margins have been trending downwards, particularly for Tier 1 retailers, indicating that retailers are not making excessive returns and that regulated pricing has served to constrain profitability.[216]

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209 Frontier Economics, Retail electricity price investigation 2024-27, 23 November 2023, p. 62.

210 Frontier Economics, Retail costs and margin, 24 April 2019, p. 29.

211 OTTER, 2025-26 Branch Operating Plan, 23 November 2023, p. 3; *Independent Competition and Regulatory Commission Act 1997, Part 4, Section 19L*; ESC, 2025–26 Strategic Plan, 23 November 2023, p. 2.

212 Regulations, s. 16(1A)(c)

213 AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 9–10.

214 Frontier Economics, Retail electricity price investigation 2024-27, 23 November 2023, p. 62.

215 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 10.

216 Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 9–10.

8.2.2 Small business margins

Various retailers, including 1st Energy, AGL, ActewAGL, EnergyAustralia, Alinta Energy and Origin Energy, supported maintaining the small business margin at 11%.[217] These retailers cited reasons including transparency, simplicity, regulatory certainty, economic conditions, viability or impacts of recent regulatory changes, including the introduction of the SSO. For instance, 1st Energy, AGL, EnergyAustralia and Origin Energy cited wholesale price volatility or changes to other elements of the cost stack such as the WEC as risks to be captured in the retail margins cost component.[218]

In general, retailer submissions contended that the presence of multiple risk drivers that could materialise should result in the current small business retail margin being maintained.

1st Energy also took the view that any lower margin level must remain sufficient to compensate retailers for compliance obligations, bad debt exposure, capital required to operate, and costs to operate billing and customer service systems. A margin too low could impair a retailer's ability to operate sustainably.[219]

1st Energy, ActewAGL and the AEC argued that reductions to the retailer margin would impact small retailers disproportionately, making it harder for them to compete.[220] The AEC stressed that additional reforms such as the accelerated smart meter rollout and consumer protection reforms have placed greater pressure on smaller retailers to compete on price and to innovate.[221]

Consumer groups supported a decrease in the small business margin, citing immediate cost relief to small businesses and uncertainty in what level of margin was efficient.[222] The ECA supported accounting for bad debt in another component of the cost stack.[223] It also went further to suggest a review of the 6% margin, stressing that small businesses had twice the rate of standing offers as residential customers. ENGIE also supported a decrease in the small business margin on the condition that higher debt costs were accounted for in other elements of the costs stack.[224]

The ECA, the JEC and SACOSS strongly supported a re-evaluation of retailer margins in response to changes to the DMO objective and methodology, specifically the efficient cost

217 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5; ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 6; AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 9–10; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 10; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 3.

218 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5; AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 9–10; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 10; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 9–10.

219 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5.

220 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5; AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 3; ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 6.

221 AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 3.

222 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 15–16; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 15.

223 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 15–16.

224 ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 8.

principle and removal of the reasonable profit consideration.[225] The ECA noted the removal of the reasonable profit consideration would support a lower small business margin.[226]

The JEC recommended that less weight be given to actual margins reported by retailers. It stated that there is insufficient evidence to suggest that actual margins were not inflated, noting ACCC findings of increased and varied margins in the market as evidence of this.[227] It stated that, if actual margins were correlated with efficiency, retailers would have reported consistent margins over time. Further, it considered that, since the 6% margin applied in DMO 7 is higher than margins used in other regulated prices (between 5.25% set by OTTER and 5.5% set by ICRC), the retail margin that the AER determines should be closer to these figures, if not lower under the new objectives.[228]

8.2.3 Form of retail margins

Many retailers preferred the percentage-based approach and that the form of methodology for retail margins should remain consistent with previous DMOs.[229] They provided similar reasoning to that outlined in section 8.2.2 – that maintaining a percentage-based approach promoted simplicity, transparency and regulatory certainty.

Other stakeholders supported the consideration of a hybrid system, where the retail margin could be recovered as a fixed dollar amount within the DMO daily supply charge with a remainder as a percentage of variable costs.[230] SACOSS encouraged the AER to explore the hybrid approach, where a portion of the margin is a fixed dollar amount and a portion is variable, to align with other regulators.[231]

Similarly, GloBird Energy noted a hybrid approach would allow consumers who use less energy to better manage their costs with margins that would be more closely linked to energy consumption.[232] The South Australian Department for Energy and Mining and SACOSS stated this would be more aligned with other regulators.[233] The South Australian Department for Energy and Mining also cited Frontier Economics' conclusion that applying a retailer

225 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 14–15; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 14–15; SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, pp. 10–11.

226 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 14–15.

227 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 14–15.

228 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, pp. 14–15.

229 Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 8–9; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 11; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 8; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 11.

230 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 5; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 16; SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, pp. 10–11; South Australian Department for Energy and Mining, Submission to DMO 8 issues paper, 12 December 2025, p. 3.

231 SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, pp. 10–11.

232 GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 5; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5.

233 South Australian Department for Energy and Mining, Submission to DMO 8 issues paper, 12 December 2025, p. 3; SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, pp. 10–11.

margin as a percentage ignores that increasing energy costs reduce the risk faced by the retailer, thereby overcompensating the retailer as energy costs increase.[234] In contrast, applying a fixed dollar value margin would undercompensate retailers, which is why Frontier Economics consider a hybrid solution preferable.[235] The JEC and ECA noted that relying on the percentage-based approach alone could amplify increases in the DMO price if underlying DMO cost components increase in value.[236]

Some stakeholders also put forward variations on the hybrid approach or other approaches to retail margin. The ECA suggested the fixed component of the hybrid form should not be indexed to CPI to avoid a feedback effect given that electricity prices impact inflation.[237] 1st Energy proposed apportioning margins to reflect the nature of the risk that each cost component bears. As such, it recommended that a larger share of the margin be applied to the variable cost component, such as wholesale risk exposure that bears greater volatility and hedging risk.[238]

8.3 Draft determination

8.3.1 Efficient retail margins

We are now required to set the DMO based on the efficient costs, including margin, of supplying electricity to small customers on standing offers.[239] We consider that Frontier Economics' advice, that efficient margins should be set in a manner such that they only compensate for the non-diversifiable or systematic risk borne by the investor, is relevant in setting efficient margins for DMO 8.[240] Under an efficient margin framework, we consider that margins should not compensate for risks that are already captured in other components of the DMO cost stack.

In setting efficient margins, we also had regard to the long-term interests of consumers, which is another mandatory consideration in the Regulations when determining the DMO.[241] For instance, margins should not be set so low that they do not sufficiently compensate retailers for risk. If this were the case, retailers may exit the market as investment in electricity retailing would likely be reallocated elsewhere with an appropriate return on investment. This would reduce competition and would not be in the long-term interests of consumers.

234 South Australian Department for Energy and Mining, Submission to DMO 8 issues paper, 12 December 2025, p. 3.

235 South Australian Department for Energy and Mining, Submission to DMO 8 issues paper, 12 December 2025, p. 3.

236 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 16; ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 14–15.

237 ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 14–15.

238 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5.

239 Regulations, s. 16(4)(a); Explanatory Statement, item 41.

240 Frontier Economics, Retail electricity price investigation 2024–27, 21 November 2023, p. 57; Frontier Economics, Retail costs and margin, 24 April 2019, p. 23.

241 Regulations, s. 16(4)(c).

8.3.2 Setting uniform retail margins

For the DMO 8 draft determination, we have decided to apply a uniform margin of 6% for residential and small business DMO prices. In determining this uniform margin, we have considered the relevant risks faced by retailers in supplying electricity to residential and small business customers and consider these are accounted for in other DMO cost components.

Bad debt risk

In the DMO 7 determination, we determined that the higher margin for small businesses reflected the greater financial risk faced by retailers in supplying electricity to this customer type, as evidenced by the higher levels of bad and doubtful debts relative to residential customers.[242]

We maintain the view that retailing to small businesses involves greater bad debt risk because a proportion of small businesses fail, leaving retailers with unpaid bills and either no or limited ability to recover debts once a business is liquidated. Bad debt levels may also vary from year to year as bad debt can be driven by macroeconomic factors that are difficult to predict. In contrast, residential customers do not present as great a bad debt risk due to smaller bills and outstanding debt, and the role of government support in assisting residential customers to pay bills.

As noted in section 7.3.4, DMO 8 includes separate residential and small business allowances for the recovery of actual bad debt written off by retailers. Since bad debt recovery is already accounted for separately for small businesses, this is not a basis for setting margins at a higher level for small business than for residential customers.

Compliance risk

Compliance risk is captured in the cost to serve component of the DMO – for example, in the inclusion of costs relating to labour, billing and IT systems. While the overall cost to serve small business customers is reported as being higher than for residential customers, we note this cost category covers other aspects of retailer services as well. We consider that small businesses generally present a lower compliance risk than residential customers. This is because retailing to residential customers obliges retailers to provide hardship programs, payment plans and systems for managing life support customers, which is not required for most business customers (although we acknowledge there are life support requirements for small businesses under certain circumstances).

Therefore, we consider that retailer risks in this regard are already accounted for in the DMO cost stack for small business customers and do not need to be factored separately into the margin.

Churn and price sensitivity risk

Retail cost data reported by retailers in 2023–24 and 2024–25 indicate that small businesses exhibited marginally lower churn rates by approximately 2% across DMO regions. This difference does not demonstrate that small business customers are more price sensitive or present greater churn risk. We also note churn risk should be captured in the separate residential and small business allowances for modest costs to acquire and retain customers.

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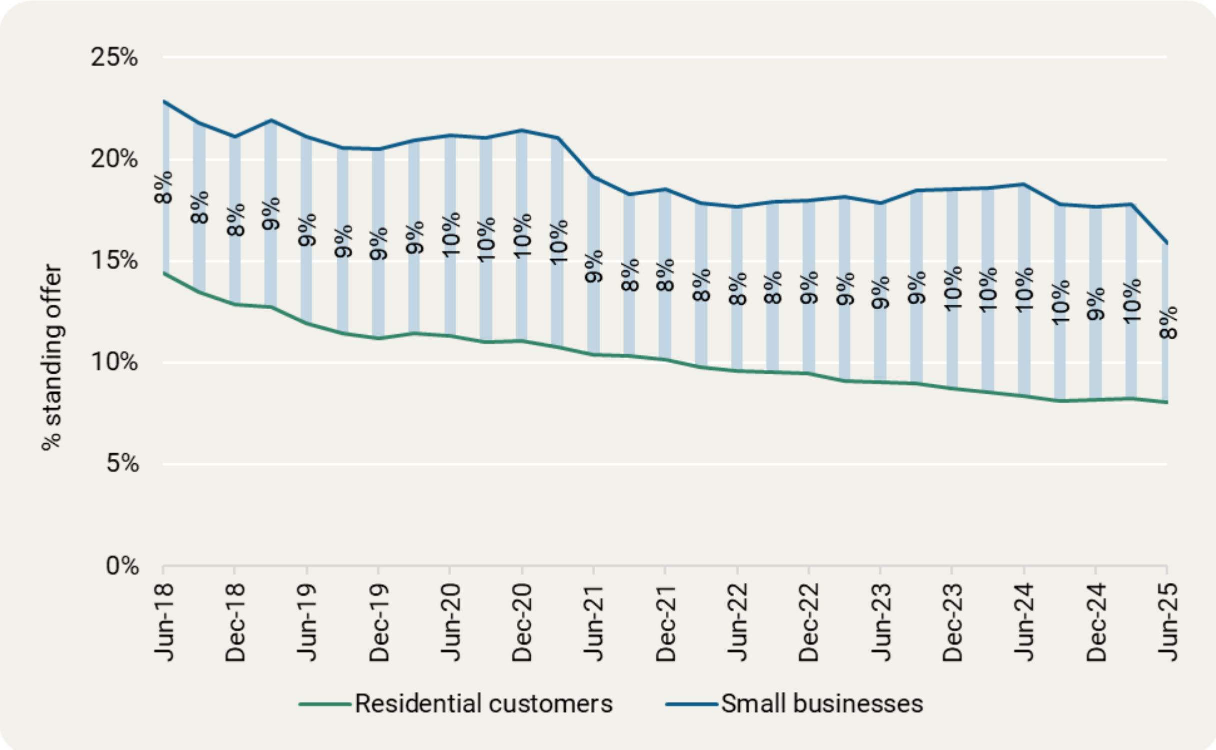
242 AER, DMO 7 final determination, Australian Energy Regulator, 26 May 2025, p. 75.

Figure 8.1 shows that, both prior and post implementation of the DMO, small businesses exhibited an 8% to 10% higher rate of standing offers relative to residential customers, suggesting that small businesses do not exhibit greater switching risk than residential customers. This suggests that, compared with residential customers, small businesses are relatively more disengaged and less sensitive to price changes. This trend is consistent with the trend in retail performance reporting data since Q1 2019 that shows small business internal switching rates from standing to market offers are consistently lower than residential customers. This reinforces lower market engagement, price sensitivity and retailer risk among small businesses.

Overall, we consider that the lower small business churn risk and price insensitivity does not justify a higher small business margin relative to residential customers under an efficient DMO pricing framework.

Figure 8.1 Customers on standing offers, across all DMO regions



Source: AER analysis of retail market performance data.

Separate retail and other costs reflect the risks of serving different customers

We acknowledge 1st Energy's views that any lower retail margin must remain sufficient to compensate retailers for compliance obligations, bad debt exposure, and operating billing and customer service systems.[243] Various retailers also cited wholesale price volatility as a risk driver, which should be captured in the retail margin component.[244]

243 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5.

244 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 10; AGL, Submission to DMO 8 issues paper, 1 December 2025, pp. 9–10; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, pp. 9–10.

We disagree with this view since the DMO cost stack already accounts for all the costs associated with a retailer's operation and delivery of services and risks it is exposed to. This includes costs the retailer must pay to use the network and recover efficient wholesale, environmental and retail costs. When considering an efficient margin for supplying electricity, we must have regard to the relevant risks that retailers face and not consider risks that have been otherwise managed through other components of the DMO cost stack. Without seeking to quantify individual risks, we have taken this into account in our determination of the efficient margin.

Our analysis in chapter 7 disaggregates retail and other costs into key cost components, including the costs to serve customers, the costs to acquire and retain customers, and other retail costs. Similar to bad debt, our approach for costs to serve allows retailers to fully recover the average costs to serve in a future DMO. Retail and other costs for small businesses are between $14.67 and $49.58 higher (ex. GST) than for residential customers, depending on DMO region.

We also consider that the wholesale cost risks of both customer types are accounted for in the wholesale cost component of the DMO. Retailers have consistently submitted that they take a portfolio approach to hedging their wholesale market exposure, effectively buying hedging products against a single load profile that comprises both their residential and small business load. Accordingly, the DMO wholesale cost uses a single aggregate load profile when forecasting hedging costs, resulting in the same WEC for both small business and residential customers.

We also observe reported small business retailer costs generally tend to be higher than residential customer costs, although our analysis indicates there are elements of lower relative risk:

- small business costs to serve are reported to be up to $5.35 to $24.41 higher (ex. GST), despite not being required to offer payment plans or hardship programs for small business customers
- small business acquisition and retention costs are reported to be up to $10.38 higher (ex. GST) relative to residential customers, although small businesses are less likely to switch.

A potential driver for these cost differences is how retailers have differentiated between residential and small businesses when reporting their costs to us. We acknowledge that many retailers do not routinely disaggregate customer bases in their standard financial reporting practices. Therefore, as part of the information request, some retailers have apportioned mass market costs into disaggregated residential and small business customer types using various allocation methodologies. These approaches included allocation based on the average number of electricity customers by DMO region, a customer's network code classification or meter types. Some retailers have also used annual MWh size to determine whether a customer is a small business, a commercial or industrial customer.

Given the retailer cost data does not appear to fully align with our findings in customer churn and engagement risk indicators, we will work with retailers to improve the transparency and robustness of customer type allocations for future DMOs.

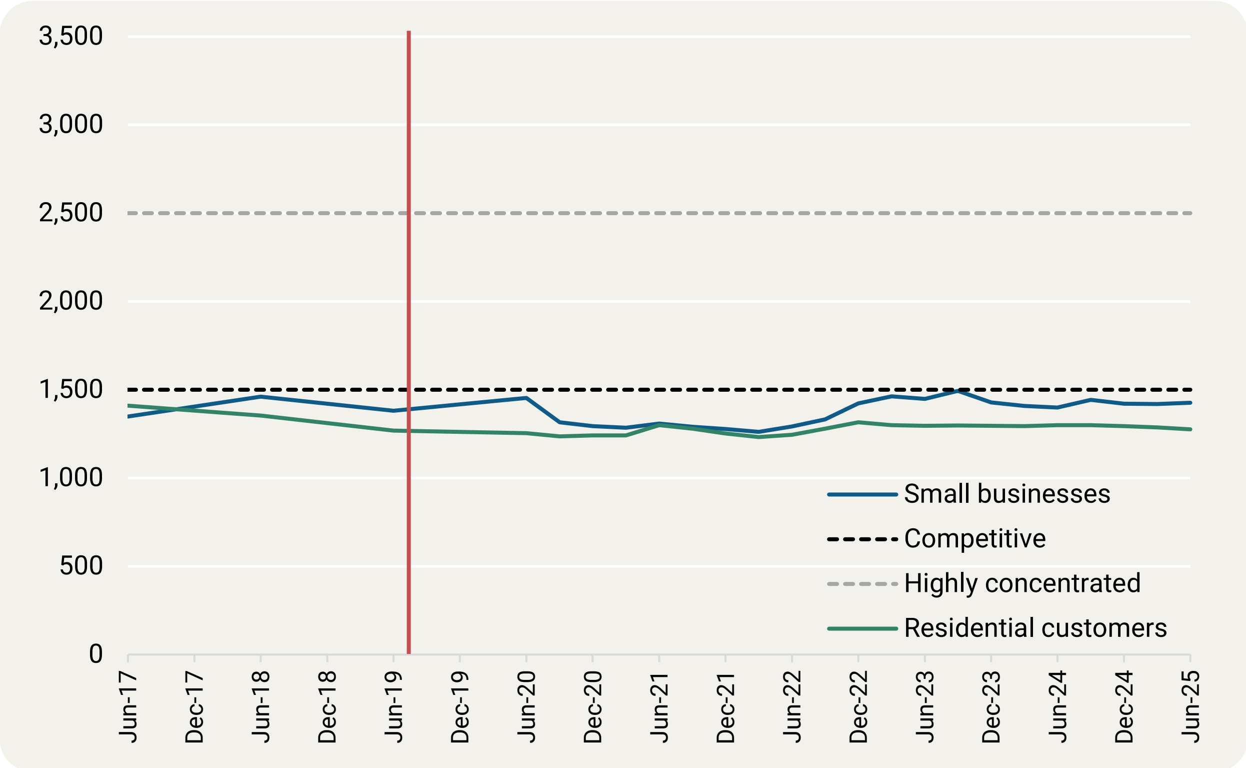
Competition has not diminished in setting uniform margins

Since the implementation of the VDO in 2019, the ESC has applied a uniform retail operating margin to the total cost stack. To examine whether a uniform margin would hinder retail competition, we assessed market concentration for the small business segment in Victoria, as measured by the Herfindahl-Hirshman Index (HHI).[245]

The HHI has remained relatively stable since 2016–17 despite introducing regulated small business retail margins of 5.7% in the first VDO in July 2019,[246] which was eventually reduced to 5% per the recent 2025–26 final decision.[247] On this basis, we consider evidence suggests that a 5% to 5.7% small business margin is at least reasonably efficient, since we have not seen retailers exit selling to small business customers (that is, re-allocate the underlying capital invested in retailing to small business customers elsewhere) in the 7-year period subject to VDO pricing regulation.

We consider that a uniform margin (with separate residential and small business actual bad debt allowance) fully accounts for the risk of retailing to small business customers, and that a uniform margin approach in Victoria since 2019 has not diminished competition in the small business segment.

Figure 8.2 HHI, by customer type, Victoria



Note: The VDO was first implemented in July 2019.
Source: AER analysis of the ESC's energy market dashboard.

245 The HHI is an internationally used metric to measure market concentration. Increases in HHI generally indicate a decrease in competition, and vice-versa.

246 ESC, Victorian Default Offer to apply from 1 July 2019, Essential Services Commission, 3 May 2019, p. 86.

247 ESC, Victorian Default Offer 2025-26 Final Decision Paper, Essential Services Commission, 21 May 2025, p. 55.

Previous margins were appropriate but not under the Regulations

For DMOs 1 to 7, we were required to set retail margins to allow retailers to make a reasonable profit when selling electricity to customers in DMO regions. This differs to the Regulations, under which we are now required to set retail margins based on the efficient costs to supply electricity to small customers on standing offers. A brief timeline on how we set these margins is summarised below.

- 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 and leave 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 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 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. These 10% and 15% residential and small business allowances would be uniform across regions. However, to avoid a large initial step change in margins, a glidepath was introduced to gradually achieve uniformity. The retail allowance was set to reflect a return on retailer risk, allow for differences in retailers' costs and provide additional room for competition. 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 to enable greater transparency on these individual components. This 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.
- In DMOs 6 and 7, we set retail margins at 6% and 11% for residential customers and small businesses, respectively. We stated in the DMO 7 final determination that retailers should receive a margin that is commensurate with the level of risk associated with the customer type, as evidenced by the higher levels of bad and doubtful debt for small businesses relative to residential customers.[248]

Under the Regulations we now have a different role to DMOs 1 to 7, which is to consider the efficient costs to supply electricity to small customers on standing offers, inclusive of margin.[249] We consider that this previous retail margin differential between residential customers and small businesses is no longer appropriate.

The 5% difference in residential and small business margins arose from the regional rebalancing of the margins present in DMO 1, where prices were set as the midpoint

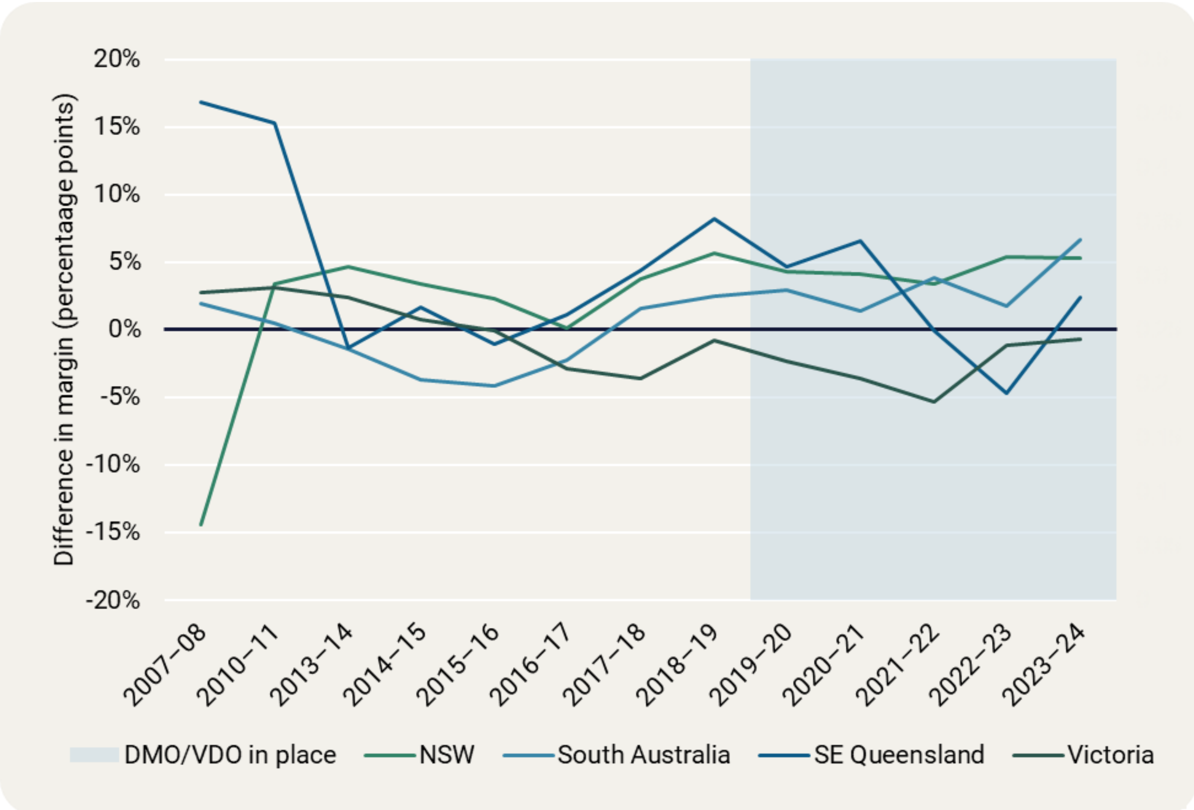
248 AER, DMO 7 final determination, Australian Energy Regulator, 26 May 2025, p. 75.

249 Regulations, s. 16(4)(a); see also Explanatory Statement item 41.

between the median standing offer and median market offer using October 2018 data between residential customers and small businesses.[250] In DMOs 1, 2 and 3 margins varied significantly across regions and customer types, ranging from an estimated 1% for residential customers with controlled load in SA Power Networks to as high as 28.5% for Ausgrid small business customers.[251] Basing DMO 1 on the structure of standing and market offers resulted in a reasonable margin and achieved the DMO objectives because the resulting DMO prices were lower than current standing offers (pricing protection against unreasonable prices) yet higher than typical market offers (incentivising competition and consumer engagement).

However, this analysis represented a point-in-time market observation, and residential and small business retail margins prior to the introduction of the DMO have fluctuated over time, as observed by the ACCC in its Inquiry into the NEM reports (Figure 8.3). As an example of the volatility observed in margins, had the DMO been introduced 2 years earlier and adopted the same initial derivation from median market and standing offers in October 2016, the resulting DMO prices – which flowed through to the retail allowance used in DMOs 4 and 5 – would have likely been equal (i.e. no margin differential) for residential and small businesses. This is because the EBITDA margins in NSW, SE Queensland and South Australia were equivalent for residential and small business in 2016–17.

Figure 8.3 Difference in small business and residential retail margins, by region



Note: Positive percentages indicates that the small business margin exceeds the residential margin, and negative percentages indicate that residential margin exceeds the small business margin. Due to data availability, data points are only available for 2007–08, 2010–11, and 2013–14. From 2013–14 onwards, data is reported annually.
Source: AER analysis of ACCC retail market inquiry data, December 2024.

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250 AER, DMO 1 final determination, Australian Energy Regulator, April 2019, p. 61.

251 AER, DMO 4 draft determination, Australian Energy Regulator, 18 February 2022, p. 42.

We consider that a differential in margins is not required under the Regulations. In a Victorian context, ACCC analysis indicates that prior to the introduction of the VDO (between 2015–16 and 2018–19), small business margins were either equal or less than the margins achieved for residential customers. That is, there are minor differences in observed retail margins between residential and small businesses.

The pricing points of standing and market offers in October 2018 adopted in DMO 1 and the observed residential and small business margin differential carried through to DMO 7 are not reasonable for setting efficient small business margins in DMO 8 for an additional reason. We consider that this differential could be a consequence of lower market engagement and price sensitivity among small business customers. For instance, prior to DMO 1, the ACCC observed in its retail electricity pricing inquiry report that the market was not functioning as intended, requiring the introduction of regulated prices. The ACCC found a high rate (approximately 40–60%) of small business customers in NSW, South Australia and SE Queensland were on standing offers or undiscounted market contracts paying the same price as a standing offer,[252] with high proportions of small business standing offer customers not switching in over 4 years.[253]

As noted previously, we acknowledge there is a different risk profile for small business compared with residential customers. However, we consider the higher risk in terms of payment default and bad debt is now accounted for in the recovery of actual bad debts elsewhere in the DMO cost stack, in a way not accounted for in DMO 7 or earlier through use of bad debt provisioning. Evidence also suggests that small business customers are likely a lower risk for churn or compliance.

8.3.3 Approach to quantifying efficient margins

In determining the 6% uniform margins, we analysed retail margins for residential customers, small business and mass market customers across a range of sources, including the EBITDA margins reported by retailers, inferring retail margins from market offers and the ACCC's customer-weighted average annual prices.

We also considered the expected returns modelling from Frontier Economics, first commissioned by the ESC in 2019, then commissioned by the ICRC in 2024. The results are not jurisdiction specific, so are also applicable to DMO regions. Frontier Economics also considered the same principles of efficiency that investors in efficient markets should be only compensated for systematic or non-diversifiable risk, which it has previously advised. We consider this analysis to be sound because the ESC also considered this approach in a Victorian context, which continues to remain competitive.

Given that there have been significant methodological changes elsewhere in the DMO 8 draft determination, we consider it prudent not to make any adjustments to the 6% retail margins at this time. Reductions in several DMO cost components as a result of methodological changes have already contributed to the decline in retail margins in dollar terms.

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252 ACCC, Retail Electricity Pricing Inquiry Final Report, Australian Competition and Consumer Commission, June 2018, p. 338, Figure 18.4.

253 ACCC, Retail Electricity Pricing Inquiry Final Report, Australian Competition and Consumer Commission, June 2018, pp. 338, 340, Figure 18.5.

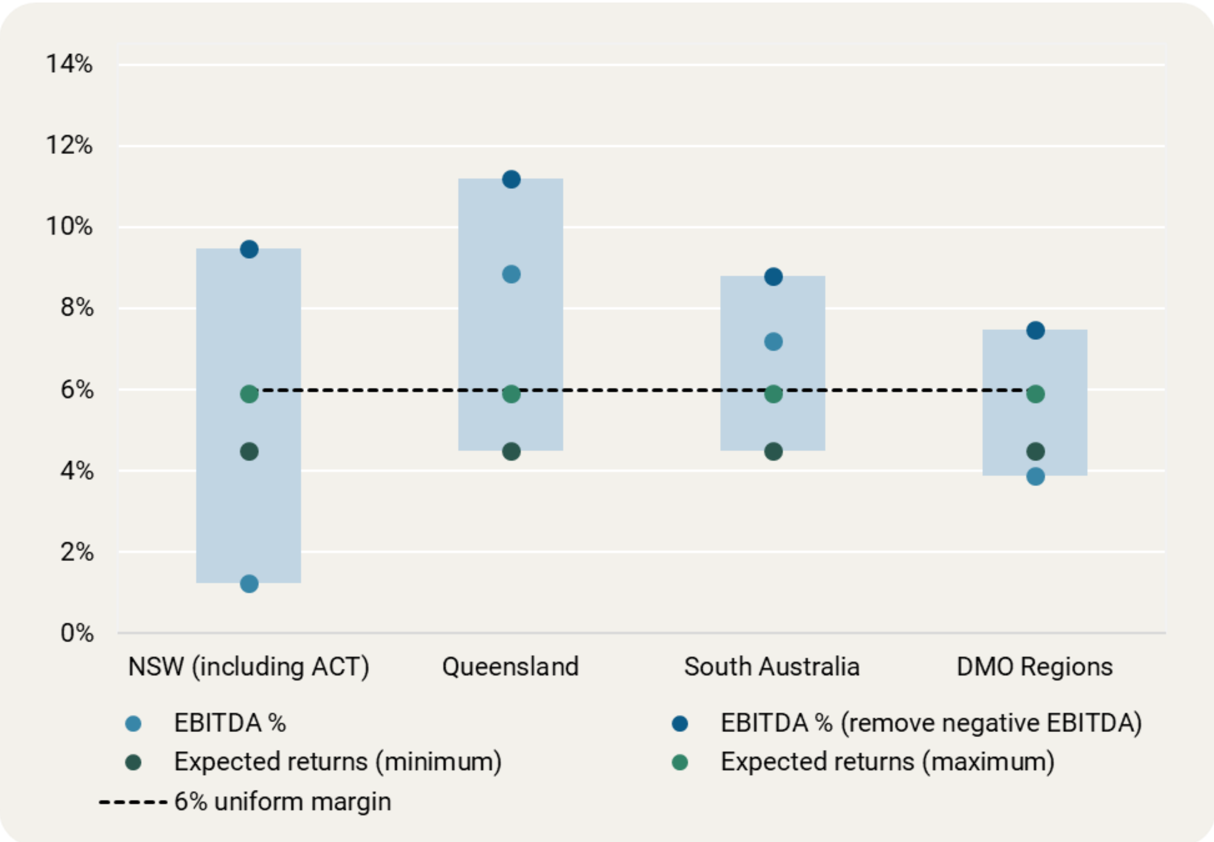
AER analysis of EBITDA margins

Figure 8.4 presents a range of observed EBITDA margins for mass market customers (residential customers and small business combined). The lower bound of our EBITDA margin analysis (3.9% DMO-wide) reflects all reported retailer margin data, including retailers that reported negative EBITDA margins, and the upper bound (7.5% DMO-wide) excludes retailers who reported negative EBITDA margins.[254] The midpoint of these ranges is 5.7%.

We consider the upper bound to be a closer reflection of an efficient margin than the lower bound, and that our determination of an efficient margin should give greater weight to the subset of retailers who incurred a positive EBITDA margin. This is because we do not consider a negative return on capital adequately compensates investors for systematic or non-diversifiable risk of retailing electricity in DMO regions.

Our decision to apply the 6% uniform margin is above the 5.7% midpoint, giving greater weight to the upper bound of 7.5%. It also marginally exceeds the upper bound of Frontier Economics' estimated 4.5% to 5.9% range (by 0.1%) using their expected returns approach, reflecting some degree of conservatism, which we consider is prudent given the significant changes elsewhere in the DMO. Considering this analysis and Frontier Economics' findings, we consider that retaining a 6% efficient margin is appropriate under the Regulations.

Figure 8.4 Range of EBITDA margins for mass market customers, by DMO region



Source: AER analysis of retailer cost information.

254 If a retailer reported a negative EBITDA for any specific customer type or DNSP, then that data point is removed. For example, if a retailer reported negative EBITDA for residential customers in NSW, then that respective EBITDA and revenue data points is removed.

Inferring margins from prices of advertised offers

We have estimated a range of margins using market offer data for each customer type and DMO region by examining residential with and without controlled load, and small business fixed rate market offers available between 1 July and 1 September 2025. To infer margins, we subtracted DMO 7 retail, wholesale, environmental and network costs from the advertised prices.

Across this period, there was a large spread of inferred retail margins. We found competitive retail prices offered had average margins of -0.1% to 7.1% for residential customers without controlled load, -0.4% to 7.4% for residential customers with controlled load and 8.5% to 11.6% for small businesses, varying by DMO region.

We weighted these retail margins using the customer counts provided by DNSPs to provide an aggregated view. This resulted in aggregated retail residential margins of 2.5% and aggregated small business margins of 9.5%. Aggregate mass market margins (across both residential and small business customers) are approximately 3.0%.

However, there are limitations in this approach. Most notably, the advertised market offers during this period were benchmarked against DMO 7 prices, which already incorporated 6% and 11% margins for residential customers and small businesses, respectively. Using advertised market offers is also likely to underestimate the prices that all customers pay and, thus, underestimate the margins achieved by retailers. This is because advertised market offers tend to be lower priced than expired market offers to attract new customers. Therefore, we consider this analysis estimating a mass market margin of 3% to represent a lower bound of an efficient retail margin.

Inferring margins from ACCC retail pricing information

We also analysed ACCC retail pricing information to estimate retail margins. In its December 2025 Inquiry into the NEM report, the ACCC collected retail pricing data across over 6.8 million residential customers in NSW, SE Queensland, South Australia and Victoria.[255]

This analysis examined the prices that customers were charged on 1 August 2025 and includes all market offers that retailers have customers on, including plans that are no longer offered to new or switching customers. Using this pricing data, the ACCC derived customer-weighted average annual prices for residential customers, with and without controlled load.

We inferred these margins by subtracting DMO 7 costs from the ACCC's customer-weighted annual prices.[256] We found using customer-weighted average annual prices had average margins of -2.1% to 3.1% for residential customers without controlled load and -1.1% to 9.0% for residential customers with controlled load. The ACCC did not collect pricing data for small business customers in this report.

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255 ACCC, Inquiry into the National Electricity Market December 2025 report, Australian Competition and Consumer Commission, 18 December 2025, p. 9.

256 ACCC December 2025 report, Supplementary Excel Spreadsheet with retail pricing data and charts, Appendix C, Supplementary tables C2.1, C2.2 and C3.1.

Benchmarking regulatory decisions in other jurisdictions

Retail margin determinations from other regulators are also relevant for consideration when determining an efficient margin for DMO prices.

These regulators have requirements to determine efficient margins. The ESC, ICRC, OTTER and QCA also set uniform margins for residential and small businesses.

Table 8.1 Comparison of regulated retail margins by jurisdiction

Regulator	State	2024–25	2025–26
ESC[257]	Victoria	5.3%	5.0%
ICRC[258]	ACT	5.2% (50:50 split between percentage and dollar terms)	
OTTER[259]	Tasmania	5.25% (50:50 split between percentage and dollar terms)	
QCA[260]	Regional Queensland	6.8%	6.7%

8.3.4 Form of efficient margins

For the DMO 8 draft determination, we have decided to maintain retail margins as a percentage of DMO 8 prices. However, we are seeking further stakeholder views on whether margins should take a different form to reduce the daily supply charge (and increase the variable charge) in the DMO tariff cap (as discussed in chapter 9).

We consider that a hybrid approach may introduce additional complexity during several changes to the DMO arising from the reforms. For example, we would be required to consider what proportion of the retail margin is allocated to the variable and fixed cost components of the DMO and determine the appropriate base year for these fixed costs.

Figure 8.5 provides an illustrative example of the annual dollar value of retail margins using the fixed percentage and hybrid approach for the residential flat rate retail tariff for different usage amounts. It shows that hardship customers, who are typically characterised by higher usage amounts than the average customer, would benefit from the hybrid approach.

We consider that adopting the percentage approach is preferable because it avoids needing to decide which cohorts within a broader group all subject to the same DMO tariff are advantaged or disadvantaged by how the margin is set.

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257 ESC, Victorian Default Offer 2025-26 Final Decision Paper, Essential Services Commission, 21 May 2025, p. 55.

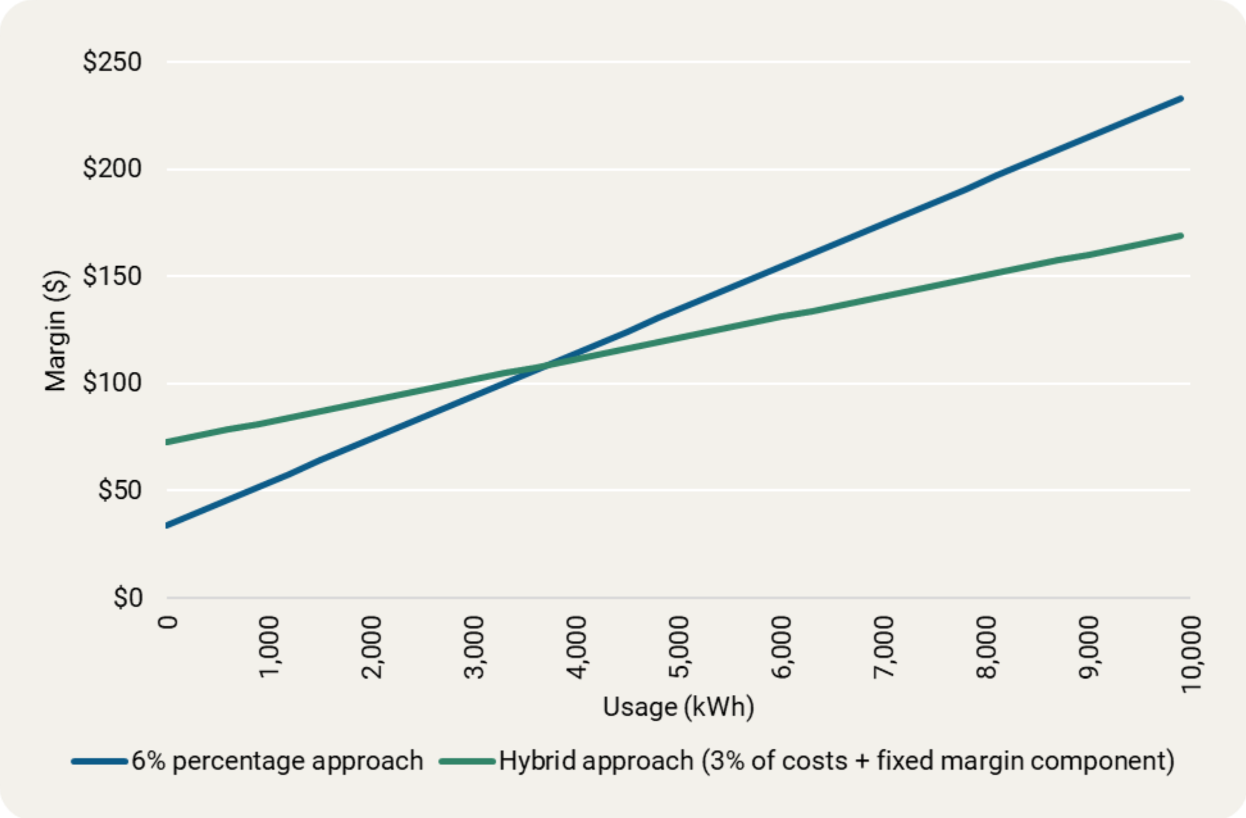
258 ICRC, Retail electricity price recalibration 2025-26: standing offer prices for the supply of electricity to small customers, May 2025, p. 13.

259 OTTER, 2025 Regulated Retail Electricity Pricing Investigation, 12 May 2025, p. 48.

260 ESC, Victorian Default Offer 2025-26 Draft Decision Paper, Essential Services Commission, 13 March 2025, p. 51.

In response to the JEC and ECA's proposal[261] to consider a hybrid approach that combines both fixed value and percentage margins, we maintain that a percentage-based approach is more appropriate because it reflects that risks scale with the underlying costs that retailers face and is also simpler and more transparent for retailers and consumers.

Figure 8.5 Form of retail margins – residential customers in Ausgrid, annual margin in $ amounts vs. usage



8.3.5 Summary

The DMO 8 draft determination applied a uniform 6% retail margin for residential customers and small businesses. This is summarised in Table 8.2.

Table 8.2 Efficient retail margins, DMO 8 draft determination and DMO 7 final determination (including GST)

Customer type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Residential flat rate					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 8 ($)	$112.35	$140.84	$150.93	$115.65	$136.18

261 JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 16; ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, pp. 14–15.

Customer type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Retail margin in DMO 7 ($)	$117.88	$144.68	$164.45	$128.55	$138.03
Difference ($)	-$5.52	-$3.84	-$13.52	-$12.90	-$1.86
Residential customers time of use					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 8 ($)	$113.18	$141.18	$150.93	$115.65	$136.18
Retail margin in DMO 7 ($)	$117.88	$144.68	$164.45	$128.55	$138.03
Difference ($)	-$4.69	-$3.50	-$13.52	-$12.90	-$1.86
Small businesses flat rate					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 8 ($)	$268.46	$262.02	$294.11	$224.66	$281.74
Retail margin in DMO 7 ($)	$547.52	$525.28	$684.43	$472.33	$609.51
Difference ($)	-$279.06	-$263.26	-$390.32	-$247.67	-$327.77
Small businesses time of use					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 8 ($)	$275.89	$263.75	$294.11	$224.66	$281.74
Retail margin in DMO 7 ($)	$547.52	$525.28	$684.43	$472.33	$609.51
Difference ($)	-$271.63	-$261.52	-$390.32	-$247.67	-$327.77

9 Annual usage amounts, timing and pattern of supply, apportionment of fixed and variable costs and comparison price

For the DMO 8 draft determination, we have:

- retained the annual usage benchmarks for residential and small business customers, including the controlled load amounts, from DMO 7
- retained our approach from DMO 7 for calculating the timing and pattern of supply, updating the usage profiles with new AEMO interval meter data
- allocated fixed costs to the daily supply charge and variable costs to the usage charge(s) for all DMO tariff caps
- used the flat rate tariff to determine the comparison price for non-regulated tariffs for residential and small business customers.

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 reference price can be calculated. Throughout this document we refer to annual supply as annual usage. We must also determine the timing and pattern of supply for residential and small business tariffs – that is, their energy usage across the day. In combination, these factors determine the 'model annual usage', which has several uses in the Regulations. The model annual usage is used to convert tariffs and offers into annual prices, which must be compared with the DMO in customer communications and marketing.

Under the Regulations we are also required to develop DMO tariff caps. When creating these tariffs, we must allocate all costs to the daily supply charge, usage charge or a mix of both.

9.1 Issues paper

9.1.1 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.

The issues paper noted the ACCC's July 2025 Inquiry into the National Electricity Market report findings on residential and small business usage, which we considered indicated that the annual usage amounts remain broadly representative for both residential and small business customers.[262]

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

Due to issues relating to year-on-year comparability of DMOs, we proposed to maintain the same usage amounts, unless large changes were identified in updated data.

9.1.2 Timing or pattern of supply

In the issues paper we proposed to review the data used in calculating the timing and pattern of supply, but we proposed to maintain the same approach as previous years. The issues paper noted that we have engaged with AEMO since DMO 7 to isolate and remove identified controlled load consumption from the interval meter data, to improve our calculations of the timing and pattern of supply.

9.1.3 Apportionment of fixed and variable costs

In the issues paper we noted that retailers' costs of supplying electricity are driven in 2 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 proposed to maintain the allocation of costs to fixed and variable tariff components in line with previous DMO determination cost assessment models, where variable costs (that were previously multiplied by annual usage amounts) were allocated to the usage charge of the tariff and any other costs were allocated to the daily supply charge. We sought stakeholder feedback on this approach.

9.1.4 Comparison price for non-regulated tariffs

The issues paper sought stakeholder feedback on how the AER should determine the comparison price for non-regulated tariffs. The issues paper referred to this as the 'maximum annual bill', which was reflective of the DMO outcomes paper language used for this function of the DMO.

We proposed to determine the comparison price by annualising the cost of the flat rate DMO tariff caps for residential and small business customers, noting it was the simplest and most transparent approach that would not be impacted by any assumptions made on usage patterns and timing.

9.2 Stakeholder views

No stakeholder submissions were submitted on the topic of annual usage amounts and timing and pattern of supply.

9.2.1 Apportionment of fixed and variable costs

Most stakeholders generally supported the proposed approach, which was to apportion fixed costs to the daily supply charge and variable costs to usage charges.[263] 1st Energy noted that this approach best reflects costs for retailers and allows them to recover their efficient costs.[264]

SACOSS urged that we consider any potential inequitable impacts from recovery of costs through usage charges for households with high energy consumption. It considered higher usage charges could lead to cross-subsidisation from high energy users to low energy users.[265]

9.2.2 Comparison price for non-regulated tariffs

Most stakeholders supported the proposed approach to annualise the flat rate DMO tariff to calculate the comparison price because it is the simplest and most transparent. Submissions noted the likely increased complexity for consumers of having multiple reference prices for non-regulated tariffs.[266]

Other stakeholders, such as SA Power Networks, recommended the AER determine a comparison price for both flat rate and time of use tariffs,[267] while Powershop considered that the most common tariff type should be adopted.[268]

9.3 Draft determination

9.3.1 Annual usage amounts

The draft determination for DMO 8 retains the current annual usage benchmarks for residential and small business customers, including the current controlled load amounts. The per-customer annual usage determination is set out in Appendix C.

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263 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 3; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 2; Energy Trade, Submission to DMO 8 issues paper, 27 November 2025, p. 1; 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 2; SA Power Networks, Submission to DMO 8 issues paper, 26 November 2025, p. 1; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 4; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 1; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 3; JEC, Submission to DMO 8 issues paper, Justice and Equity Centre, 1 December 2025, p. 7; AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 1; ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 7; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5.

264 1st Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 2.

265 SACOSS, Submission to DMO 8 issues paper, South Australian Council of Social Service, 1 December 2025, pp. 8–9.

266 ActewAGL, Submission to DMO 8 issues paper, 26 November 2025, p. 3; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, pp. 2–3; EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 4; GloBird Energy, Submission to DMO 8 issues paper, 26 November 2025, p. 2; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 3; AEC, Submission to DMO 8 issues paper, Australian Energy Council, 26 November 2025, p. 1; ECA, Submission to DMO 8 issues paper, Energy Consumers Australia, 26 November 2025, p. 7; Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, p. 5.

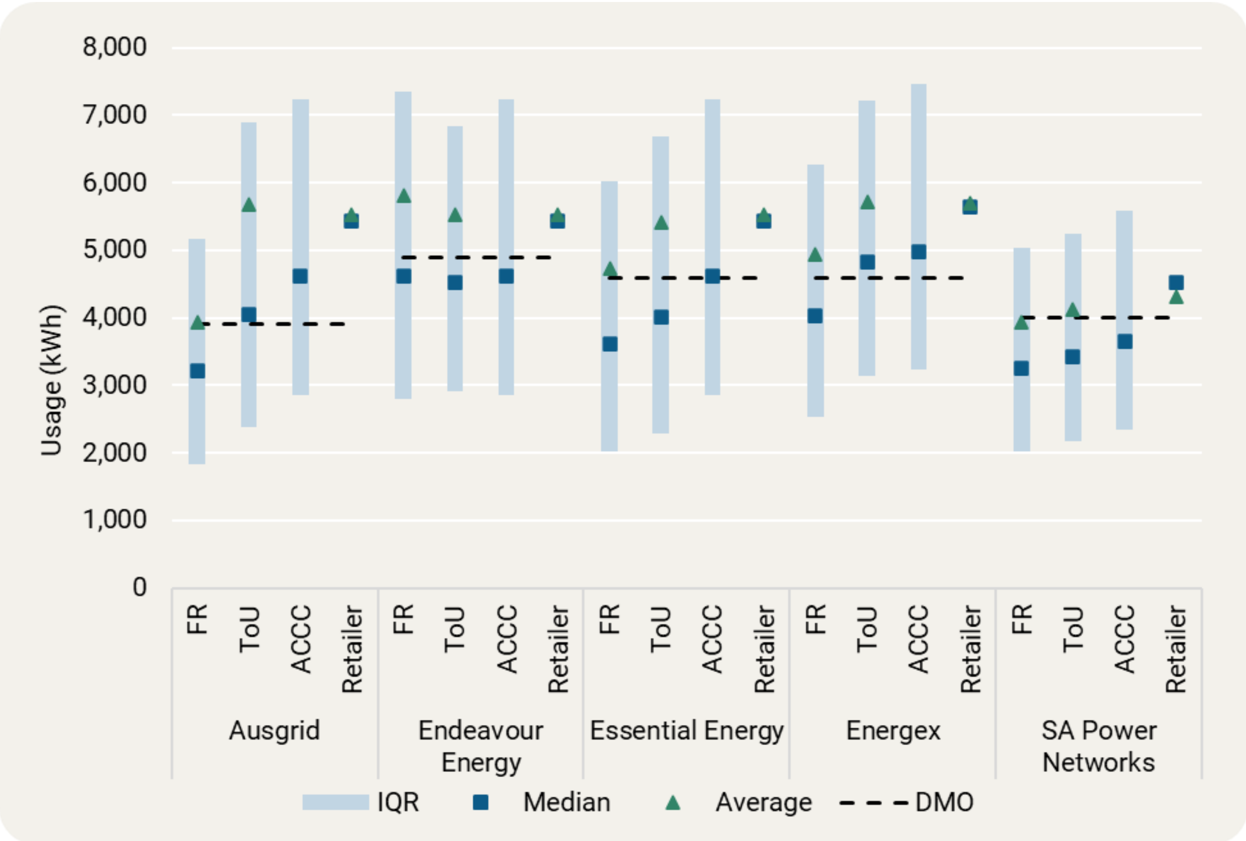
267 SA Power Networks, Submission to DMO 8 issues paper, 26 November 2025, pp. 1–2.

268 Powershop, Submission to DMO 8 issues paper, 28 November 2025, p. 2.

We have examined data we collected from DNSPs and retailers in all DMO regions and considered the consumption information published by the ACCC in its July 2025 Inquiry report.[269] As set out below, the benchmarks we have retained for the DMO 8 draft determination are well within the range of the ACCC data and the majority for flat rate and time of use network data for all DMO customer types.

While we have maintained our standard approach for DMO 8 because the data does not show clear evidence to depart from the current benchmarks, we acknowledge there is potential improvement to this aspect of the methodology. However, without clear evidence that there are material differences, we consider the potential benefits of a change in methodology do not outweigh the benefits of continuity and comparability at this time. Continuity and consistency align with the new objective of providing a fair, trusted and reasonably priced DMO for all consumers.

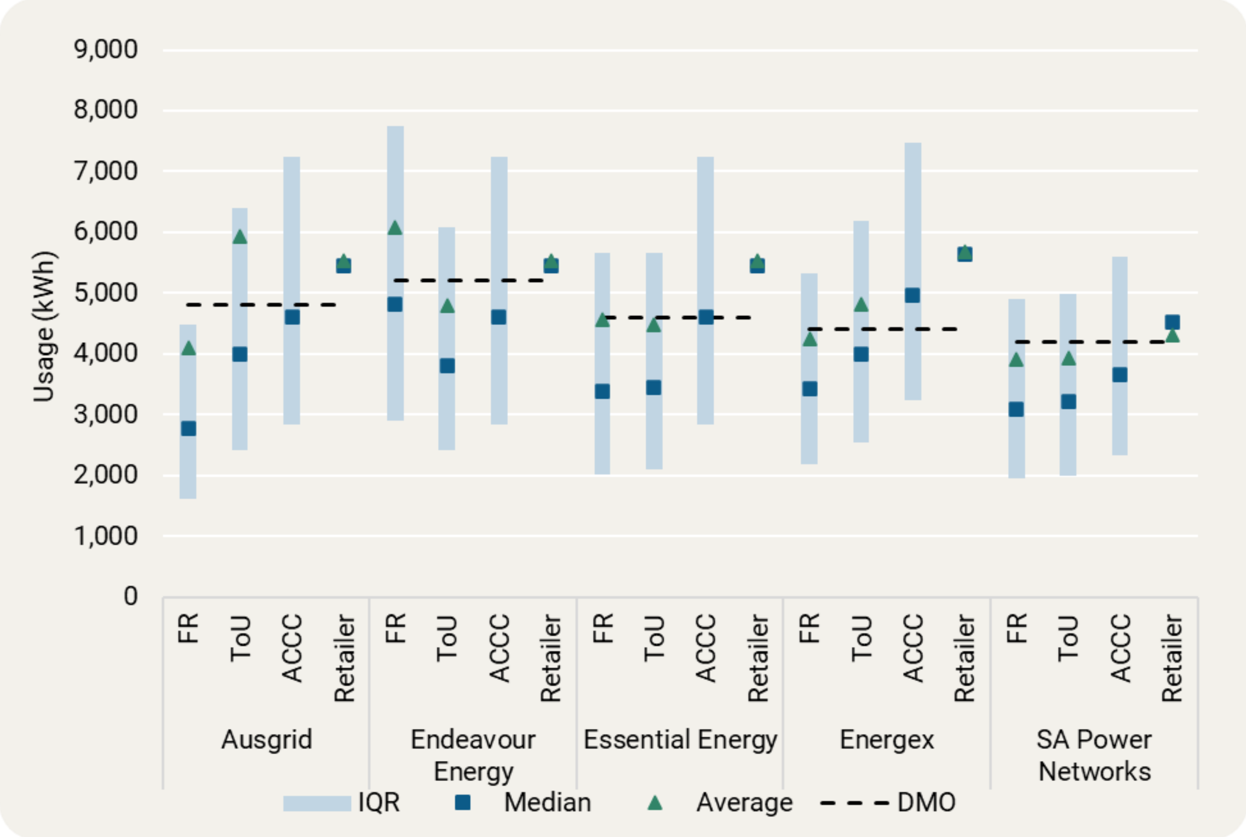
Figure 9.1 Fixed rate and time of use DNSP usage for residential customers without controlled load



Note: FR = Flat rate network tariff consumption data. ToU = Time of use network tariff consumption data. ACCC = ACCC July 2025 report consumption data. Retailer = Retailer data collected by retail cost information notices. IQR = Interquartile range.
Source: Data received from DNSPs of annual usage amounts for 2024–25, ACCC, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report, July 2025 and data collected from retailers via retail cost information notices.

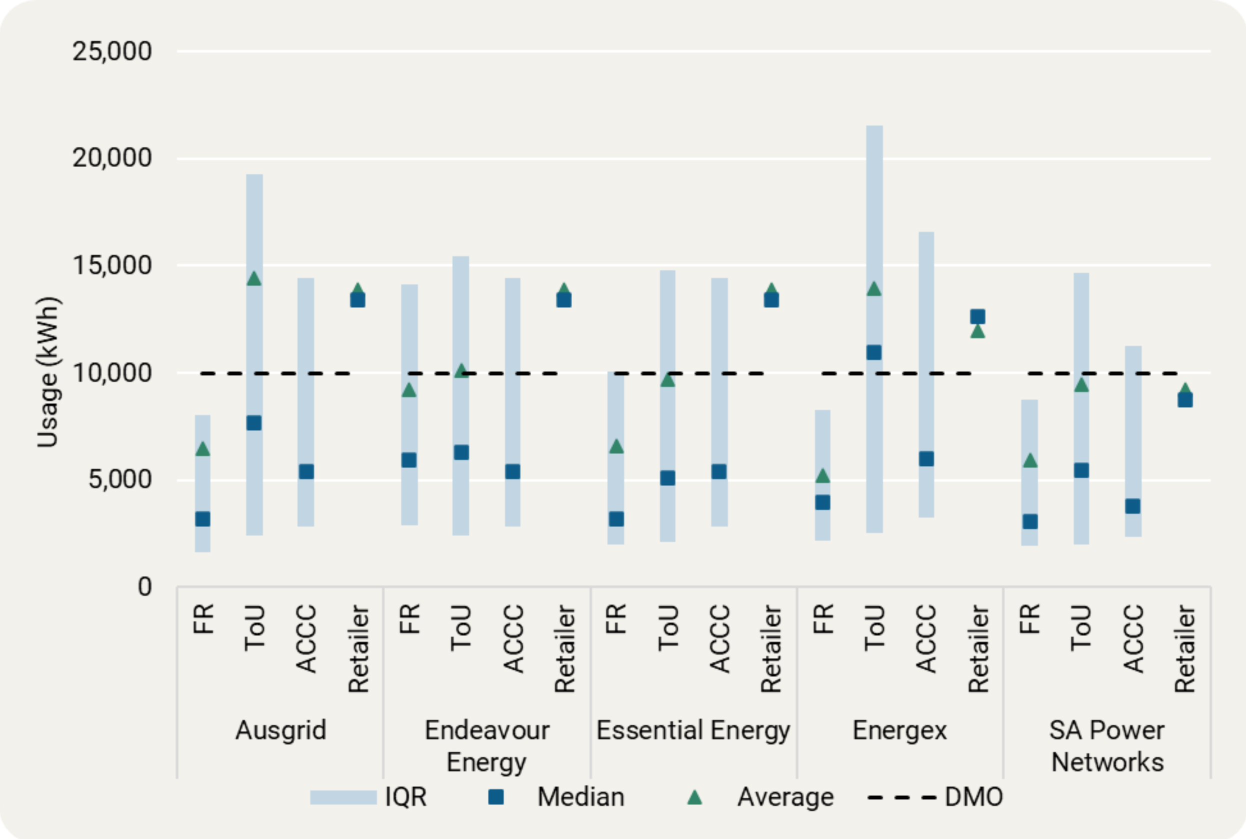
269 ACCC, Inquiry into the National Electricity Market report – July 2025 | ACCC, Australian Competition and Consumer Commission, Appendix E.

Figure 9.2 Fixed rate and time of use DNSP usage for residential customers with controlled load



Note: FR = Flat rate network tariff consumption data. ToU = Time of use network tariff consumption data. ACCC = ACCC July 2025 report consumption data. The median and interquartile ranges for the combined general use, controlled load circuit 1 and 2 is unable to be computed as they were only specified for each controlled load circuit. Retailer = Retailer data collected by retail cost information notices. IQR = Interquartile range.
Source: Data received from DNSPs of annual usage amounts for 2024–25, ACCC, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report, July, 2025 and data collected from retailers via retail cost information notices

Figure 9.3 Fixed rate and time of use DNSP usage for small business customers without controlled load



Note: FR = Flat rate network tariff consumption data, ToU = Time of Use network tariff consumption data, ACCC = ACCC July 2025 report consumption data, Retailer = Retailer data collected by retail cost information notices. IQR = Interquartile range.
Source: Data received from DNSPs of annual usage amounts for 2024–25 FY, ACCC, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report, July 2025 and data collected from retailers via retail cost information notices.

Figure 9.3 demonstrates a much wider range in small business usage, particularly for Ausgrid and Energex time of use data. For all DNSP datasets, fixed rate average and median were below the 10,000 kWh amount, while most time of use medians were also below this amount. However, we consider the 10,000 kWh usage amount to be broadly representative because it is within the interquartile range for all ACCC usage amounts, and within the flat rate and time of use network data.

While retailer usage median and averages are above the DMO annual usage amounts in all cases, except SA Power Networks small business, there are differences in the populations of the underlying datasets compared with networks data. They still fall within the interquartile ranges of ACCC and the majority of networks' datasets.

9.3.2 Timing and pattern of supply

As proposed in the issues paper, we have removed identified controlled load consumption from the interval meter dataset to improve our calculations of the timing and pattern of supply.

The approach uses updated AEMO interval meter data to determine the timing and pattern of supply but retains our key assumptions from previous determinations, including to:

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

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

For SA Power Networks time of use controlled load tariff, we have derived a simple consumption pattern that allocates 58% of usage into the evening off-peak window, 42% into the solar sponge and 0% into peak periods. This allocation is based on 2 years of available interval meter data provided by SA Power Networks.

9.3.3 Apportionment of fixed and variable costs

Our draft determination assigns recovery of fixed costs to the daily supply charge and recovery of variable costs to the usage charges in the DMO tariffs. This proposed approach was broadly supported by stakeholders, allows for the accurate and equitable recovery of fixed and variable costs across all ranges of customer usage amounts and is consistent with the tariff setting approaches adopted by the QCA and ESC.

While we consider this decision aligns with the Regulations in respect of the efficient costs of supplying standing offer customers, we are also cognisant that adopting this approach results in some daily supply charges in DMO tariff caps that are higher than those in current standing offer tariffs set by retailers. This is in part due to the previous DMO determinations setting an annual price cap rather than caps at the tariff level. The previous determinations allowed retailers to set the tariff levels as they saw fit (allocations of cost recovery between daily supply and variable charges) if they complied with the overall annual price.

DMO 8 will be a structural change for the way standing offers and the respective tariffs are set because retailers no longer have the flexibility to adjust their own standing offer tariff levels. As such, we are conscious that the higher DMO 8 daily supply charges may impact consumers. While prices are decreasing from DMO 7 levels, we are conscious that some consumers may incur a bill shock because the way these costs are recovered will change (with an increase in supply charges and a decrease in usage charges).

Given this change and uncertainty on the exact impact to consumers (it will depend on each consumer’s consumption profiles and the standing offer they are on), we have considered 3 options that would shift the recovery of some components from the daily supply charge to the usage charge. We welcome stakeholder feedback on this aspect of the draft determination, which will inform our consideration of this issue for the final determination.

Option 1: Allocating bad debt to the usage charge

Option 1 treats bad debt as a variable cost component, which recognises that debt may scale with usage. However, some retailers argued that bad debt can arise regardless of consumption because bad debt is more linked to the number of customers served.[270] Only Powershop considered that bad debt can be proportional to customer bill sizes.[271]

In contrast to allocating bad debt as a fixed cost component, this approach benefits low-usage customers who would otherwise contribute to the same bad debt recovery through the daily supply charge. Under this approach, bad debt would be expressed as a percentage of reported retailers' electricity usage, as collected from our 2024–25 retail cost information request.

If bad debt was recovered entirely through the usage charge, it would reduce the daily supply charge by approximately $0.10 to $0.25 per day, while the usage charge would increase between 0.4 and 1.2c/kWh (inc. GST), depending on customer type and DMO region.

However, a key drawback to this approach is that there is a risk of over-recovery of bad debt costs from consumers who typically consume large amounts of energy, which is a common feature of customers on hardship or payment plans. For example, in the ACCC's July 2025 Inquiry into the NEM report, the median usage among hardship and payment plan customers was approximately 76% and 58% higher than median usage across all customers.[272] This means that hardship and payment customers could contribute 76% and 58% more to bad debt cost recovery than the median customer if this bad debt is allocated wholly as a variable component of the DMO, which could exacerbate energy affordability for these customers. There is also the potential under-recovery of debt to the extent that some of the costs associated with written off debt do not scale with usage.

Option 2: Allocating the retail margin to the usage charge

Option 2 allocates the entire retail margin to only the usage charge component for all DMO tariffs. Submissions mostly supported adhering to a percentage approach for the margin that applies to both the daily supply and usage charges.[273] This shift in cost recovery directly reduces the daily supply charges faced by standing offer customers by 6% and reduces bill impacts for consumers who have relatively low consumption levels.

The limitation of this approach represents a significant departure from previous DMO determinations. It introduces complexities in determining the appropriate margin to include in the usage charge and makes it more difficult to compare with EBITDA reported by retailers. It also makes it more difficult to compare with the ESC, OTTER, ICRC values for margin (which are set as a percentage of both daily supply and usage charges). Furthermore, as the margin would be fully allocated to usage charges, higher energy users would pay higher bills under this approach and a greater dollar amount relative to the percentage-based approach.

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270 EnergyAustralia, Submission to DMO 8 issues paper, 28 November 2025, p. 10; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 9.

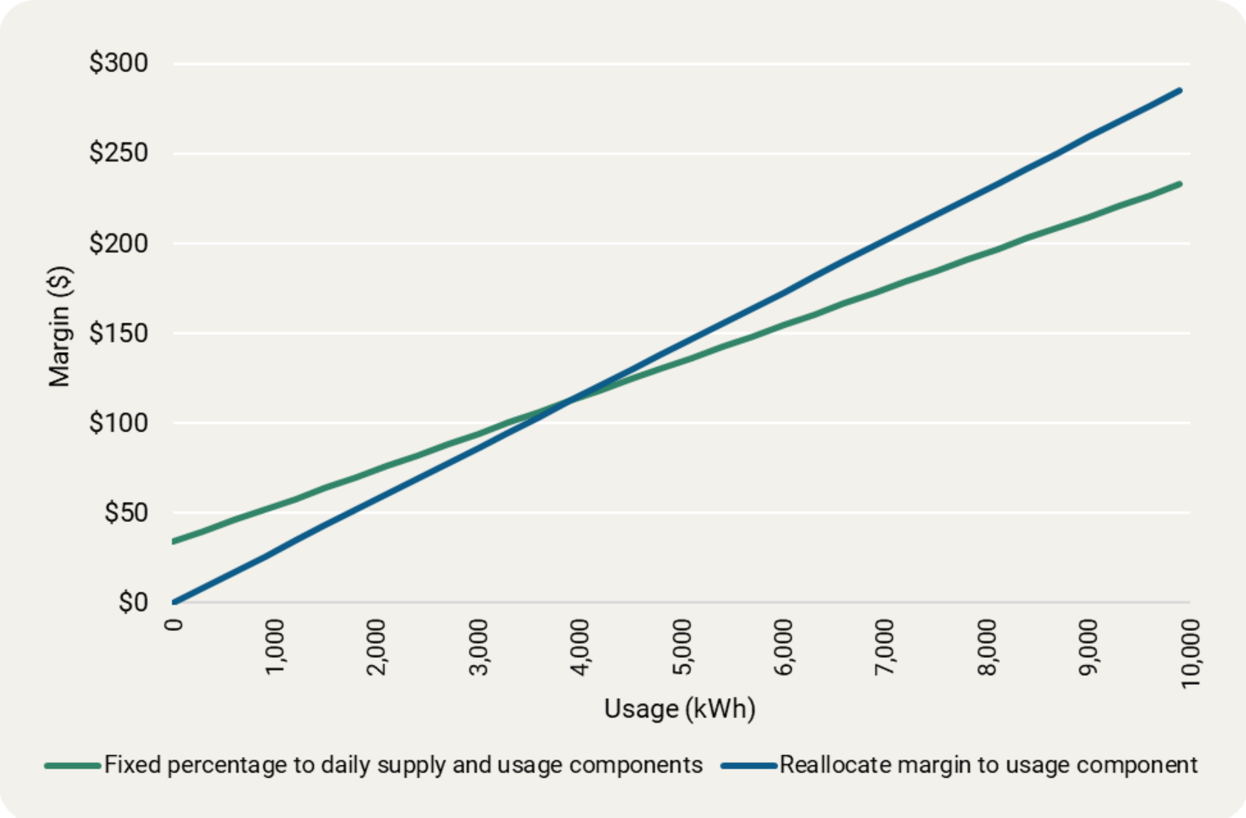
271 Powershop, Submission to DMO 8 issues paper, 28 November 2025, pp. 2–3.

272 AER analysis of ACCC July 2025 report, appendix E Supplementary table A3.18.

273 Alinta Energy, Submission to DMO 8 issues paper, 28 November 2025, pp. 8–9; Origin Energy, Submission to DMO 8 issues paper, 1 December 2025, p. 11; ENGIE, Submission to DMO 8 issues paper, 26 November 2025, p. 8; AGL, Submission to DMO 8 issues paper, 1 December 2025, p. 11.

As an example, Figure 9.4 illustrates estimated margin for different margin amounts in dollar terms for option 2, compared with the fixed percentage approach.

Figure 9.4 Options on form of retail margins – residential customers on flat-rate tariffs in Ausgrid, annual margin in $ amounts vs. usage



Note: Assumed usage for residential customers on flat-rate tariffs in Ausgrid is 3,900 kWh.

Option 3: Specific manual adjustment, shifting a percentage of the daily supply charge to the usage charge

For option 3, we would shift a specific percentage of the daily supply charge to the usage charge. For example, a 20% shift for Ausgrid residential flat rate customers would see the daily supply charge fall from 154.9 c/day to 123.9 c/day, while the usage charge would increase from 33.6 c/kWh to 36.5 c/kWh (inc. GST).

This approach does not change the annual comparison price because the increase in the usage charge perfectly offsets the decrease in the daily supply charge. This approach could be applied once in DMO 8 to reduce the step change in daily supply charges that would otherwise occur without an adjustment, then removed for DMO 9.

However, we are aware that adopting this change may introduce complexity and reduce certainty for retailers. It could also introduce other consumer impacts, because shifting recovery of fixed costs into the variable usage charge introduces over or under-recovery of fixed costs from different customers depending on consumption.

This risk of this arbitrary adjustment is that it may not reflect how retailers incur best estimates of efficient costs. It would also introduce complexity and reduce certainty for retailers – the value of the factor shifting costs from the daily supply charge to the variable usage charge may shift from year to year.

Shifting recovery of fixed costs into the variable usage charge introduces over or under-recovery of fixed costs from different customers depending on consumption. For instance, our retail cost information dataset shows that retailers have significantly varying average customer consumption (the 75th percentile retailer's average customer usage can by twice as high as the 25th percentile retailer's average customer usage). This would advantage retailers with average consumption greater than the DMO usage amount and disadvantage retailers with average consumption less than the DMO usage amount.

9.3.4 Comparison price

Under the Regulations, the AER is to calculate an annual comparison price for each customer type for non-regulated tariffs. The comparison price provides price protection for standing offers that cannot be readily compared with the flat rate, time of use or SSO DMO tariff caps.

We have decided to set the comparison price for non-regulated tariffs by annualising the time of use DMO tariff cap using the standard usage amounts for residential and small business customers (as set out in Appendix C).

We have favoured simplicity in adopting this approach, rather than setting multiple comparison prices or using the most common tariff type. However, we have also considered that all non-regulated tariff types are likely to be more complex than a simple flat rate tariff, which would require having a smart meter installed. Because of this, we consider annualising time of use tariffs would be the most relevant price for consumers to use as a basis of comparison.

10 Solar Sharer Offer

For the DMO 8 draft determination we have decided to:

- set free usage periods of 11 am to 2 pm in NSW regions and Energex, and 12 pm to 3 pm in SA Power Networks, on a fixed local time basis without variation
- design the SSO tariff by overlaying free usage periods on the corresponding time of use DMO tariffs to best maintain pricing signals and reflect varying costs to supply customers throughout the day
- reapportion costs incurred during the free usage period to all non-free usage periods of the day on a volume-weighted basis
- set the reasonable use tariff cap based on the corresponding off-peak or solar soak SSO tariff rate to reflect the efficient costs incurred by retailers for supplying electricity to customers during the free usage period.

On 4 November 2025 the Australian Government announced a new flexible tariff category under the DMO framework called a Solar Sharer Offer (SSO). This opt-in electricity offer is being implemented in DMO regions from 1 July 2026.[274] Retailers with more than 1,000 residential customers across all DMO regions will be required to offer the SSO to customers.

The Australian Government's objective for the SSO is to enable all residential customers with a smart meter the ability to access 3 hours of free electricity to benefit from Australia's abundant solar generation. Customers who take up the SSO, and can shift energy usage into the designated free usage period, will have the opportunity to save on their electricity bills. A reasonable use cap has been set by the government and applies to the free usage period. This cap of 24 kilowatt hours (kWh) is based on an average 5-plus person household shifting its total daily usage into the free usage period and is designed as a constraint on excessive electricity use during this period.

As shown in Figure 10.1, the 3-hour free usage period would occur during the day when solar energy is abundant and electricity is cheapest.

[274] DCCEEW 2025, More Australian homes to get access to solar power, Department of Climate Change, Energy, the Environment and Water, media release, 4 November 2025.

Figure 10.1 Load shifting example under the Solar Sharer Offer

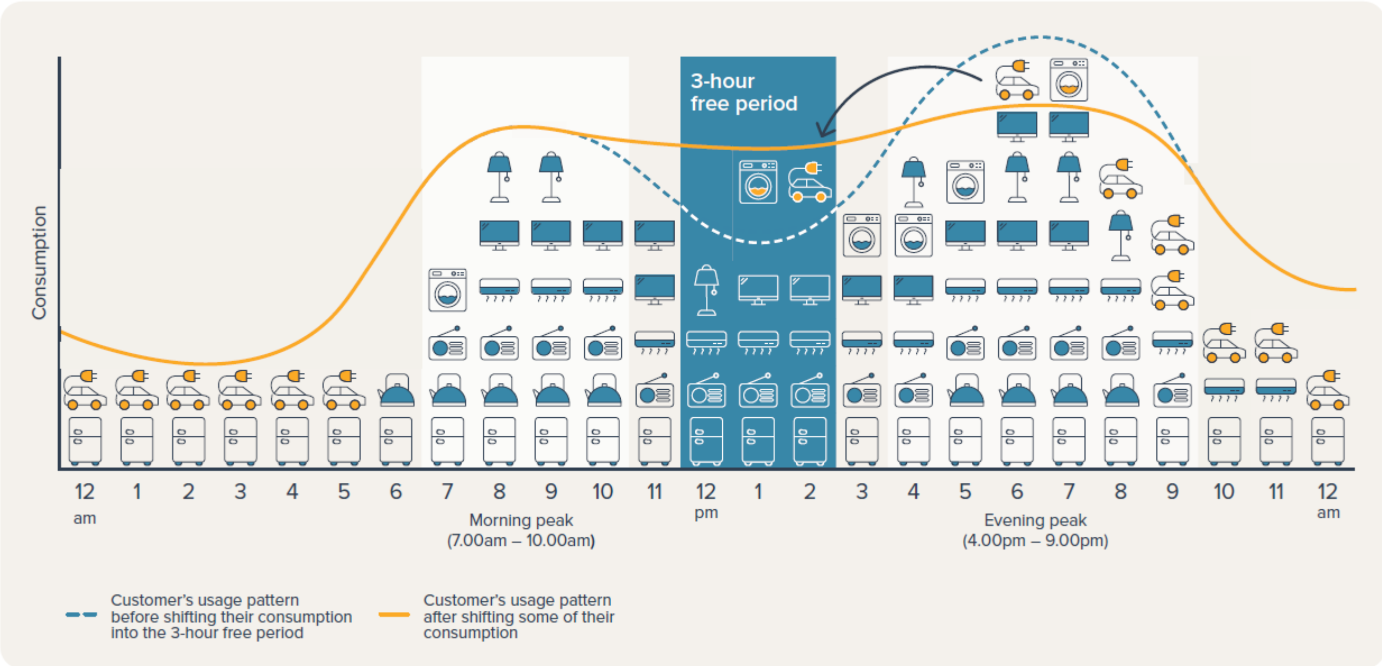


Figure 10.1 illustrates how, by shifting consumption from peak usage periods to the free usage period, consumers can smooth their consumption profile. This has the effect of reducing strain on the grid during peak periods, improving system efficiency and lowering overall system costs.

Under the Regulations, the AER must determine a model annual usage, tariff caps and a comparison price for the SSO.[275] This must be done in accordance with the DMO objective and mandatory considerations.[276]

In addition, the Regulations require the AER to:

- determine a 3-hour period each day when energy usage up to 24 kWh is free[277]
- consider and align periods of high solar generation and low wholesale and network costs when setting a free usage period for each DMO region[278]
- determine a reasonable use tariff cap for usage over 24 kWh during the free usage period.[279]

275 Regulations, s.16(1A).

276 Regulations, s. 16(4).

277 Regulations, Division 3, s.18 (1–2). The government has set the reasonable use cap at 24 kilowatt hours as per s.18(3)(a) of the Regulations.

278 Regulations, Division 3, s.18A(a–b).

279 Regulations, s. 18(4).

The Regulations also provide a degree of discretion to the AER for how it makes its determination.[280] In this respect, we considered 6 design principles for the SSO set out by the government in the SSO outcomes paper published on 23 January 2026.

SSO design principles

Looks to deliver bill savings for SSO households. The SSO should be designed to assist households who can shift load to reduce bills and be simple for consumers to understand if it's the right choice for them.

Considers key market factors and system efficiency. The SSO should see to enhance overall system efficiency through alignment with key market factors and appropriate network tariffs.

Is flexible and aligns to local conditions. The AER will determine the most appropriate time the consecutive 3-hour free usage period should apply in each DMO region.

Considers retailer viability. The SSO design should ensure customers who shift load are better off overall, while allowing retailers to recover efficient costs.

Applies a reasonable use cap. The Government has set the reasonable use cap at 24 kWh.

Is adaptable. For its first year, the SSO should prioritise practicality in implementation. A post-implementation review will provide an opportunity to adjust settings for subsequent SSOs.

When considering decisions on the SSO, we have referred to the appropriate design principles that have informed that decision.

10.1 Consultation approach

As the government was consulting on policy and implementation for the SSO during October and November 2025, we did not consult on it as part of our DMO 8 issues paper.[281] The issues paper signalled that the AER may, if necessary, conduct its own SSO-related stakeholder engagement to help inform the approach to determining the SSO for DMO 8.

We have considered the 76 submissions to the government's consultation paper from retailers, DNSPs, consumer and community organisations, academics, individuals and one

280 s. 16(4)(d) states that the AER must have regard to any other matter we consider relevant when determining annual prices and tariff caps. In addition, the AER may have regard to other relevant system and market factors when determining free usage periods if we consider it relevant and appropriate to do so (s.18A(c) of the Regulations).

281 DCCEEW 2025, Have your say on a Solar Sharer Offer (SSO), Consultation Paper, Department of Climate Change, Energy, the Environment and Water, 4 November 2025.

state government agency. We focused on feedback on design elements of the SSO relevant to the AER's role, such as setting the free usage period and recognising costs incurred by retailers during this period.

Following publication of the SSO outcomes paper, we consulted a sample group of impacted stakeholders – including retailers, DNSPs and consumer groups – on the design principles of the SSO as outlined in the paper. To better understand the operation of an SSO tariff, we also used voluntary information requests to seek insights from retailers with experience offering or developing SSO-like tariffs.

Our approach to this engagement was shaped by the compressed timeframe. This engagement has been referred to in this chapter as our targeted engagement. We are mindful that this approach meant not all stakeholders have had the opportunity to engage with these issues yet. We welcome detailed engagement and feedback through this draft determination.

10.1.1 Free usage period

When determining the 3-hour free usage periods we considered:

- how periods of high solar generation (including large-scale solar and rooftop solar) and low wholesale and network costs aligned throughout the day[282]
- key market factors and local conditions in DMO regions[283]
- simplicity and practicality for implementation and customer understanding.[284]

These considerations meant that we needed to balance our approach to optimising the free usage periods in each DMO region, reflecting the impact of local factors such as daylight savings, and ensuring practicality in implementation and communication. For example, we considered whether we should apply a uniform free usage period across all DMO regions. We discussed these issues with stakeholders in our targeted engagement.

10.1.2 Tariff structure

In designing the first SSO, the AER must have regard to the same mandatory considerations as other DMO standing offer tariffs:

- efficient costs of supplying electricity to small customers on standing offers
- types of small customers on standing offers
- the long-term interests of consumers.

In addition, we tested various SSO design elements with stakeholders in our targeted engagement. This included seeking views on the most appropriate:

- tariff structure – whether the SSO should be a simpler tariff structure with a uniform charge outside of the free usage period or be a more complex structure with peak and off-peak charges

282 Regulations, Division 3, s.18A.

283 Consistent with design principles 2 and 3.

284 Consistent with design principles 1 and 6.

- cost basis – how we can best reflect the underlying costs, such as wholesale and network costs, incurred by retailers to supply SSO customers (this is different to the SSO tariff structure, which is the customer-facing element)
- approaches to cost recovery – how we can ensure costs incurred by retailers during the free use period are recovered within parts of the SSO tariff outside of the free usage period.

We explored different approaches to ensuring that retailers can recover their efficient costs.[285] The AER has discretion as to whether costs incurred during the free usage period are recovered through raising the fixed daily supply charge or the variable usage charge(s) for the non-free usage periods. This matter was featured in some submissions to the government's consultation and informed our targeted engagement and voluntary information requests to retailers already offering free usage period plans.

10.1.3 Reasonable use tariff cap

The Regulations require the AER to set a reasonable use tariff cap for electricity consumed during the free usage period in excess of the reasonable use cap, which has been set at 24 kWh.[286] In our targeted engagement with stakeholders, we explored what such a charge should be.

This included whether the reasonable use tariff cap should be set at a level intended to deter customers from excess usage, or whether it be set to reflect the marginal costs of the excess consumption during that period.

10.1.4 Consumer behaviour

Although not a requirement of the Regulations, another matter we discussed during our targeted stakeholder engagement was whether and how to predict customers' behaviour when on the SSO. Assumptions on how a customer uses electricity while on the SSO impacts how we estimate costs incurred by retailers to supply these customers.

We also sought insights on this in our voluntary information requests to retailers offering free usage period plans.

10.2 Stakeholder views

10.2.1 Free usage period

In submissions to the government's consultation paper, Ausgrid and Powershop both cautioned against setting a 'one-size-fits-all' free usage period for all DMO regions, as each network would have unique characteristics, while Alinta Energy expressed a preference for

285 Consistent with design principle 4.

286 Regulations, s. 18(4).

national uniformity.[287] ECA expressed preference for alignment of the free usage period between states and regions where practicable.[288]

Tesla and the Clean Energy Council both noted that there would be a trade-off between the simplicity offered by a uniform national free usage period and the technical optimality of DNSP-specific windows.[289] Tesla considered that in the long term, free usage periods could evolve to become more dynamic or household-specific to better suit market and network conditions. In a joint submission, the JEC, ACOSS, SACOSS and QCOSS also all called for the free usage period to vary by region to better reflect wholesale market conditions.[290]

Most stakeholders emphasised that having a different free usage period in each DMO region would be difficult from both a customer communications and practical implementation perspective. GloBird Energy, Powershop, the AEC and the JEC all expressed a preference for state-based timing, although GloBird Energy and AGL noted that having a different period in each state would still be quite burdensome to implement for retailers. Powershop preferred state-based timing to provide consistency in messaging for customers and simplicity in implementation for retailers and government messaging. The JEC considered that state-based timing would allow the free usage period to respond to meaningful jurisdiction-specific conditions, helping mitigate risks. Origin Energy expressed a preference for national uniformity for the initial SSO and added that economic curtailment of renewable generation should be considered when setting the free usage period times.

In bilateral meetings, each DNSP provided us with guidance on what times they would prefer for a free usage period. Ausgrid and Endeavour Energy both recommended times between 10 am and 2 pm, with Ausgrid noting that a 10 am start would minimise the risk of commercial and residential peaks overlapping, and Endeavour Energy recommended the SSO align with its existing 10 am to 2 pm solar soak window in its underlying network tariffs. Essential Energy highlighted concerns with the SSO, particularly around the application to all regions regardless of the impact on demand or time of year. It suggested that if the SSO must be applied regardless of demand impact or time of year, then ensuring the free usage period sits around the middle of the day would provide the most benefit in using available solar energy.

Energy Queensland preferred setting the free usage period for its region as between 11am and 2pm, as this period is within its off-peak TOU charging window during which Energex and Ergon Energy distribution charges for residential customers are set at zero. However, it noted from an engineering perspective that the introduction of a free usage period at the retail level may cause some localised issues and constraints. SA Power Networks considered that 11:30 am to 2:30 pm South Australian time would be ideal for the network

287 Ausgrid, Submission to Solar Sharer Offer consultation, 28 November 2025, p. 1; Powershop and Shell Energy, Submission to Solar Sharer Offer consultation, 28 October 2025, p. 3; Alinta Energy, Submission to Solar Sharer Offer consultation, 21 November 2025, p. 8.

288 ECA, Submission to Solar Sharer Offer consultation, Energy Consumers Australia, 28 November 2025, p. 17.

289 Tesla, Submission to Solar Sharer Offer consultation, 21 November 2025, pp. 7–8; Clean Energy Council, Submission to Solar Sharer Offer consultation, 21 November 2025, p. 4.

290 JEC, Submission to Solar Sharer Offer consultation, Justice and Equity Centre, 21 November 2025, p. 17.

due to having the lowest general net demand based on current information but suggested 12 pm to 3 pm as a 'next best' option for simplification purposes.

In its submission to the government's consultation, Energy Queensland suggested that we align the free usage periods with the corresponding network tariffs' off-peak or solar soak periods, which are different across the DMO regions.[291]

Regarding implementation of the free usage periods, EnergyAustralia noted that billing customers in local time would likely deliver a better customer experience.

10.2.2 Tariff structure

In our consultations, stakeholders were split on the preferred structure of the SSO. EnergyAustralia, Origin Energy, SACOSS and the AEC supported a flat structure outside of the free usage period on the basis that it would allow the initial SSO to be simpler and more practical for customers to understand and for retailers to implement.

1st Energy, AGL, ENGIE, the ECA, GloBird Energy and the JEC all supported a time of use structure. 1st Energy and the JEC considered that a time of use structure would provide better price signals to incentivise customers to shift load from peak periods rather than off-peak periods. The JEC also considered that any customer who adopts the SSO would be doing so with the implicit understanding that energy prices would vary with time. The ECA preferred that the SSO have a time of use cost structure due to it providing a better broad signal for when to consume electricity. GloBird Energy warned against applying a flat structure to customers on time of use network tariffs. ENGIE considered a time of use structure would more closely reflect the underlying network tariff structure for customers with smart meters. AGL considered consistent time of use cost structures could most closely reflect efficient costs of supply, and noted a more complicated SSO design would leave room for retailers to provide comparable but simpler market offers.

Cost basis

Stakeholders in our targeted consultation also had varied views on the appropriate cost basis and DMO tariff alignment for the SSO. Origin Energy supported using the flat rate DMO cost basis for the SSO and considered that alignment of costs with the flat rate DMO would be more suitable for customers that are less engaged. 1st Energy and ECA considered a time of use cost basis to be more appropriate.

OVO Energy considered that any single 'one-size-fits-all' approach to cost recovery would incur risks because the assumed costs may differ to what retailers actually incur. Additionally, it considered that differing network costs and tariffs across and within DMO regions should be captured in the design of the SSO. The JEC observed pros and cons of either cost basis, noting that the flat rate DMO would be the typical comparison point but it may be more appropriate to align with the time of use DMO if a time of use structure is adopted for the SSO.

Retailers' recovery of costs incurred in the free usage period

The government's consultation did not focus on the precise design of the SSO tariff, but some stakeholders did touch on certain aspects in their submissions in relation to

291 Energy Queensland, Submission to Solar Sharer Offer consultation, 27 November 2025, p. 3.

recognising and allocating costs across the fixed and variable components of the SSO tariff. Many stakeholders, including larger and smaller retailers, consumer groups and other industry groups, highlighted the importance of ensuring the SSO tariff is designed to ensure retailers recover their costs, including those that will still be incurred during the free usage period.[292]

In a joint submission to the government, the JEC, ACOSS, QCOSS and SACOSS recommended that the daily supply charge should not be elevated.[293] They considered that moving costs into the variable component of tariffs would be preferable because it would allow consumers to adjust behaviour to 'mitigate the costs incurred.' The Tech Council of Australia[294] also noted that elevating the daily supply charge would have a regressive effect. Compliance Quarter[295] raised a concern about allocation of costs to peak usage charges, noting that it would exacerbate inequality for customers unable to shift load.

In bilateral meetings, the JEC preferred only elevating the peak usage charge to narrow the scope of the impact while still ensuring variable costs are recovered through usage charges only. EnergyAustralia preferred that costs incurred during the free usage period be recovered across the remaining 21 non-free hours, rather than being concentrated in peakier time of use charges, to support clearer customer outcomes and more stable cost recovery. Powershop preferred the SSO ensure fair recovery of all costs (such as network and wholesale) across all time periods (whether 2, 3 or 4-part time of use tariff is implemented).

During our targeted consultation, some retailers supported elevating the daily supply charge to recover costs incurred during the free usage period. AGL and GloBird Energy noted that cost recovery through the supply charge would be the only way to ensure retailers can recover their costs from customers who shift significant amounts of their load. 1st Energy and GloBird Energy suggested partial apportionment of costs into both the supply charge and usage charges. GloBird Energy supported a 50/50 split between the daily supply charge and peak usage charge to strike a balance between the objectives of minimising risk to retailers and encouraging customers to change their behaviour.

10.2.3 Reasonable use tariff cap

In our bilateral engagements, many stakeholders noted that most households would be unlikely to meet the 24 kWh reasonable use cap. AGL and SACOSS considered that the reasonable use tariff cap should just be cost-reflective. SACOSS noted a sharper charge would be a potential risk for high-usage households, while AGL considered it would introduce complexity that may not be needed. On the other hand, Origin Energy and GloBird Energy suggested higher charges to provide a stronger disincentive for high consumption. EnergyAustralia suggested that for simplicity and avoidance of customer confusion we should use an existing charge rather than introduce a novel one.

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292 For example, Origin Energy, Submission to Solar Sharer Offer consultation, 21 November 2025, p. 1; GloBird Energy, Submission to Solar Sharer Offer consultation, 23 November 2025, pp. 1–2; ECA, Submission to Solar Sharer Offer consultation, Energy Consumers Australia, 28 November 2025, p. 22–23; Clean Energy Council, Submission to Solar Sharer Offer consultation, 21 November 2025, p. 3.

293 JEC, Submission to Solar Sharer Offer consultation, Justice and Equity Centre, 21 November 2025, pp. 15–16.

294 Tech Council of Australia, Submission to Solar Sharer Offer consultation, November 2025, p. 9.

295 Compliance Quarter, Submission to Solar Sharer Offer consultation, 21 November 2025, p. 2.

1st Energy considered that the reasonable use tariff cap itself should be recalibrated to avoid disproportionate concentration of load within the free usage period, as it would necessitate increased cost recovery in other periods.

10.2.4 Consumer behaviour

Submissions to the government did not generally feature detailed commentary on assumptions of behavioural change, although AGL, ENGIE and EnergyAustralia all noted the need to model and forecast consumer behaviour.[296] ENGIE suggested this be informed by the experience of retailers with existing free usage period plans.

Most retailers in our targeted consultation considered that we should assume some degree of load shift when pricing the SSO. AGL suggested we use different usage profiles for the SSO compared with the DMO, while GloBird Energy supported pricing the SSO based on the most expensive potential customers, who would be able to shift nearly all their load into the free usage period. Origin Energy suggested that the AER could initially assume customers on the SSO will shift 5 kWh of usage into the free usage period, reflecting a 2 kWh assumed shift and a 3 kWh risk premium until there is actual data on customer demand. Retailers with experience offering or trialling free usage period plans reported differing experiences, with one finding little behaviour change, one finding significant load shift, and others finding increased usage across the day rather than any load shift. However, some of these retailers noted that they were unsure if these customers would be representative of SSO customers.

Most consumer groups we consulted opposed any load shift assumption for the first SSO, with SACOSS emphasising that not all customers would be able to shift load and the JEC arguing that an initial assumption of no load shift would be the simplest option and one that would best mitigate risks to consumers.

EnergyAustralia noted that any reference price comparisons for time of use tariffs like the SSO should continue to use the existing 48-interval usage profile (the pattern of supply) and be made using a single comparison basis.

10.2.5 Other SSO feedback received

We also acknowledge submissions received from stakeholders on our issues paper that primarily discussed the SSO.

The Queensland Electricity Users Network considered the SSO would likely result in retailers recouping costs through the 21 non-free hours of the SSO and non-DMO retail offers, impact on retailers' demand forecasts and hedging strategies, and potentially impact on the viability of retailers and their willingness to offer innovative products. It also cautioned that many consumers may be unable or unwilling to shift their energy use to the middle of the day.[297]

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296 AGL, Submission to Solar Sharer Offer consultation, 28 November 2025, p. 2; ENGIE, Submission to Solar Sharer Offer consultation, 21 November 2025, p. 7; EnergyAustralia, Submission to Solar Sharer Offer consultation, 26 November 2025, p. 4.

297 Queensland Electricity Users Network, Submission to DMO 8 issues paper, 1 December 2025, pp. 3–17.

Etrog Consulting considered the AER should communicate directly with customers to ensure the SSO is designed in a way that avoids customer confusion and ensures customers are able to benefit from shifting their energy use.[298]

10.3 Draft determination

10.3.1 Free usage period

Free usage periods in each DMO region

For the DMO 8 draft determination, we have applied the following free usage periods for the SSO tariffs (fixed in local time, year-round):

- **NSW DMO regions (Ausgrid, Endeavour Energy and Essential Energy):** 11:00 am to 2:00 pm local time (AEST/AEDT)
- **SE Queensland (Energex):** 11:00 am to 2:00 pm local time (AEST)
- **South Australia (SA Power Networks):** 12:00 pm to 3:00 pm local time (ACST/ACDT).

We have set the free usage periods at local time year-round. This provides a consistent free usage period start time for customers on the SSO. Our decision is based on stakeholder feedback that the SSO be simple for customers to understand, which provides them the best opportunity to shift load and/or consider if the SSO is right for them. We are interested in stakeholder views on setting the free usage periods in local time from a communications and billing systems perspective.

We consider the free usage periods best align with the timing of factors specified in the Regulations. This includes periods of high solar generation (both rooftop and large-scale) and low wholesale prices and network costs in each DMO region.[299]

The Regulations allow the AER to have regard to other relevant system and market factors if we consider it relevant and appropriate to do so.[300] Therefore, we have also considered minimum demand as an explicit additional factor due to it being referenced in the government's SSO outcomes paper and its relevance as a system factor that reflects periods of increased system vulnerability and surplus generation.[301]

Our approach to identifying the optimal free usage periods is illustrated in Figure 10.2. We used state-level datasets from the past 5 years to identify periods of high solar generation and low wholesale prices and minimum demand while also reflecting changes in local time for daylight savings. We have also endeavoured to align free usage periods with periods of low network costs on a DNSP level by assessing default time of use network tariffs and other time of use network tariffs with low-cost periods in the middle of the day. Choosing to place the free usage period when costs in the energy system are low means if a customer shifts some of their load into the free usage period, retailers will have relatively lower costs that they need to recover.

298 Etrog Consulting, Submission to DMO 8 issues paper, 1 December 2025, pp. 3–7.

299 Regulations, s.18A(a)–(b).

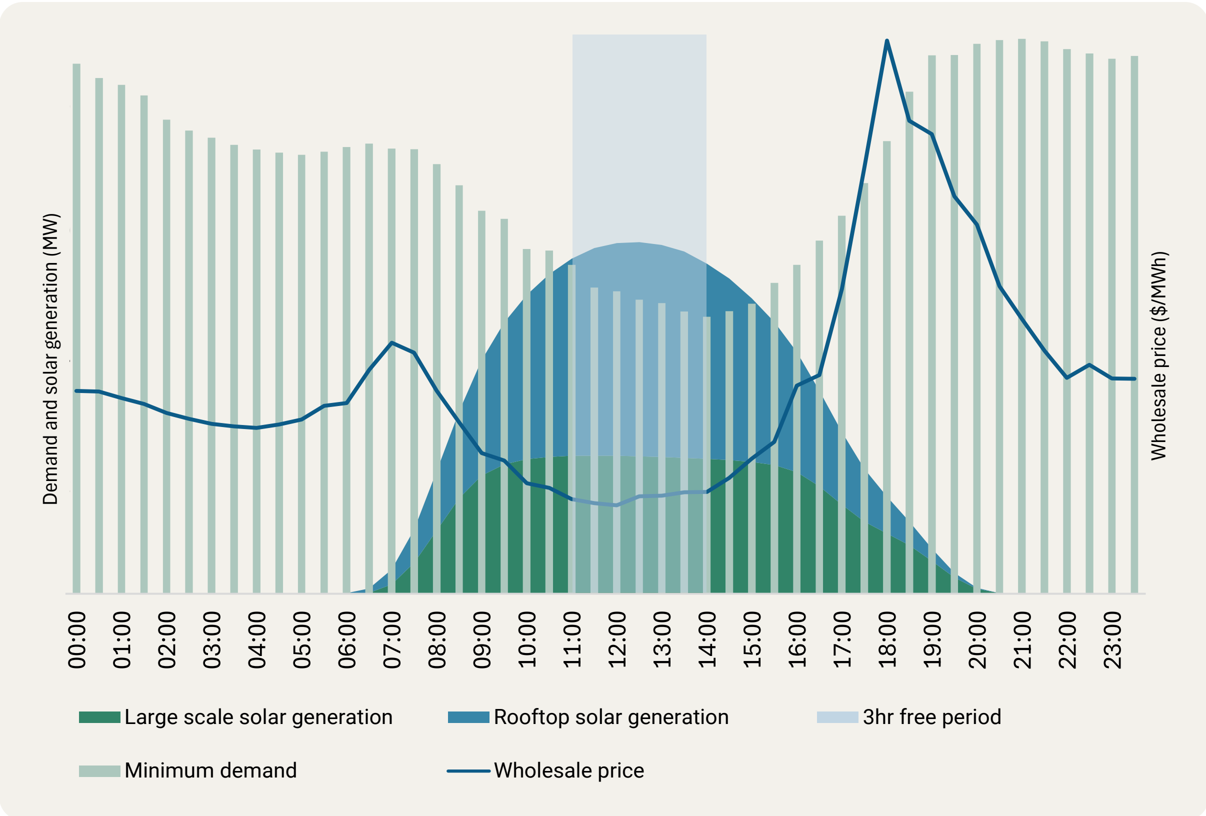
300 Regulations, s.18A(c).

301 DCCEEW, Solar Sharer Offer consultation outcomes paper, Department of Climate Change, Energy, the Environment and Water, 23 January 2026, p. 8.

We also considered Origin Energy's suggestion about economic curtailment of renewable generation to assist in aligning electricity use with surplus renewable generation in the NEM. Curtailment typically occurs when supply materially exceeds demand and price signals are low or negative. Accordingly, the key drivers associated with curtailment have been reflected through our modelling (such as demand and solar).

The continuous 3-hour period with the greatest alignment between these factors was selected as the optimal free usage period for each DMO region. The optimal free usage period is the same for all NSW regions and Energex. SA Power Network's optimal free usage period is later due to the occurrence of negative wholesale prices in the early afternoon, which is driven by large-scale renewable investment and high rooftop solar generation in South Australia.

Figure 10.2 Illustrative example to identify the optimal free usage period



Note: Rooftop solar generation is stacked on top of large-scale solar generation to give an indication of total solar generation. Network costs are not included in the figure due to visualisation constraints but they were included in our analysis.

Uniformity of the free usage periods across DMO regions

The government's SSO outcomes paper stated that the AER should set the timing of the free usage periods according to each local distribution network area.[302] Therefore, our draft determination has set the SSO free usage periods in accordance with conditions observed in each DMO region. From a practicality and simplicity perspective, we consider it appropriate to align the free usage periods across NSW regions. This strikes a balance between meeting

302 In accordance with design principle 3.

the SSO outcomes paper's design principle to align with local conditions and maintaining simplicity and ease of customer understanding.

Our analysis included other options, such as setting a uniform free usage period across all DMO regions as well as setting individual free usage periods for each distribution network area (that would include individual periods for the NSW distributors – Ausgrid, Endeavour Energy and Essential Energy).

However, we consider aligning the free usage periods across all DMO regions may create inefficiencies and misalignment with optimal local conditions. For example, based on our modelling, setting SA Power Networks' free usage period earlier in the day to align with other DMO regions would result in the free usage period coinciding with wholesale prices and native demand levels that are approximately 12% and 41% higher on average, respectively. We also consider that setting individual free usage periods for each region would lead to some confusion for customers in NSW.

We welcome stakeholder views on the trade-off between the simplicity of a uniform free usage period across all DMO regions and optimising the SSO settings in alignment with local conditions.

10.3.2 Tariff structure

Our draft determination sets the design of the SSO tariff structure by overlaying the designated free usage periods onto the corresponding distribution networks' time of use DMO tariffs (Figure 10.3). This approach best reflects the varying costs to supply customers throughout the day and maintains pricing signals for customers to shift electricity use into the free usage period.

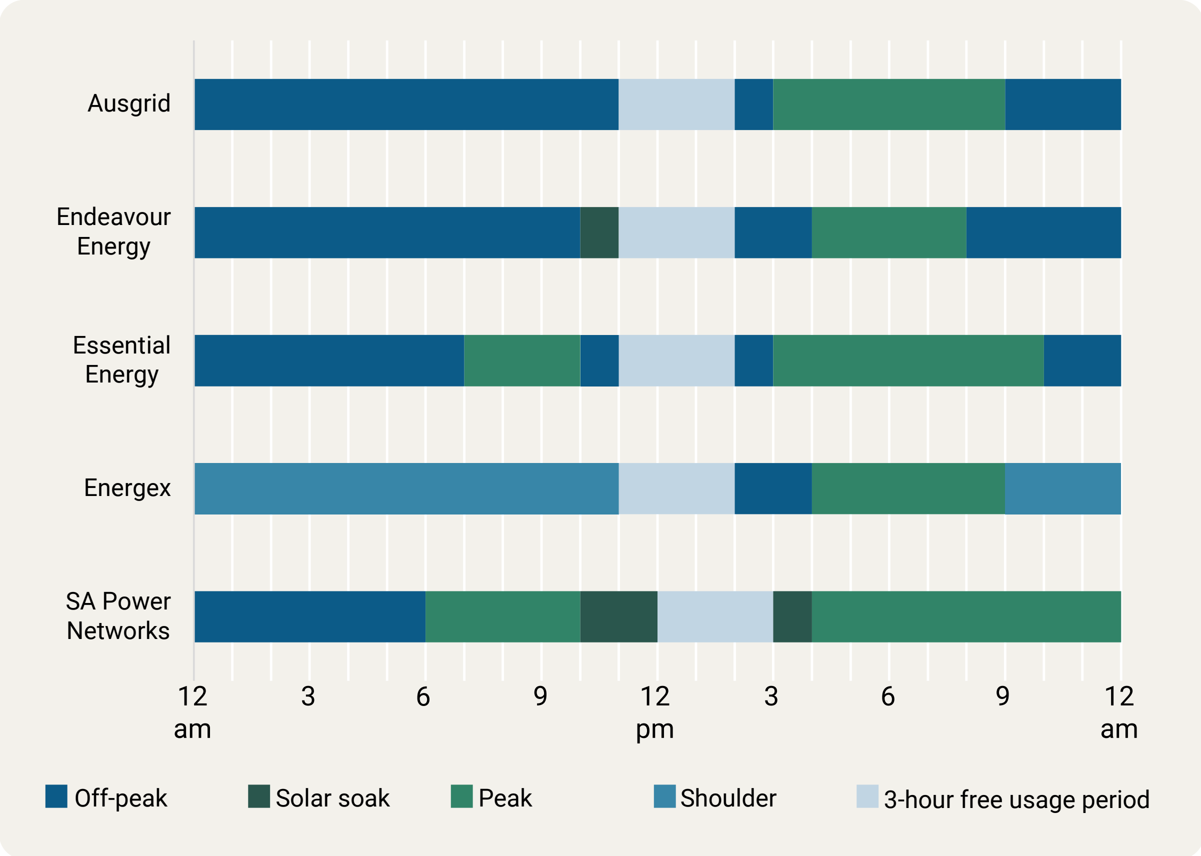
We agree with stakeholder views that a time of use tariff structure best incentivises customers to shift electricity use out of peak periods. Maintaining a peak charge aligns with the intent behind the SSO to incentivise customers to shift use from evening peaks, and other peak times, into the middle of the day to reduce system-wide demand stress.[303]

As highlighted by some retailers, a time of use SSO tariff structure also better aligns with the underlying time of use network tariffs that may be assigned to customers receiving a smart meter. As explained earlier, the SSO will only be available to residential customers with smart meters.

Our analysis included different types of tariff designs, including a simplified 2-period tariff structure for the SSO, with a free usage period of 3 hours and flat usage charge for the remaining 21 hours. The key advantage of this tariff structure is that it is simple and likely to be easily understood by customers. However, it is misaligned with underlying time of use network tariffs and has relatively weaker pricing signals. Under this structure, the pricing signal sent to customers is to treat all non-free usage periods equally, which sits in tension with the intent to shift electricity use out of peak periods.

303 Design principle 2 (Aligns with key market factors). DCCEEW, Solar Sharer Offer consultation outcomes paper, Department of Climate Change, Energy, the Environment and Water, 23 January 2026, p. 17.

Figure 10.3 Proposed SSO tariff structures (local time)



Cost basis

We have based the SSO tariff structure, and therefore retailers' cost to supply SSO customers, on the time of use DMO. This approach reflects that it is effectively a different type of time of use tariff. Using a pre-existing cost basis that already seeks to allow retailers to recover efficient costs goes part way to ensuring retailers can recover efficient costs to supply customers on the SSO. This also ensures that the total annual bill for the SSO generally aligns with the time of use DMO.

Therefore, the SSO cost basis includes the following cost components explained in earlier chapters of this draft determination:

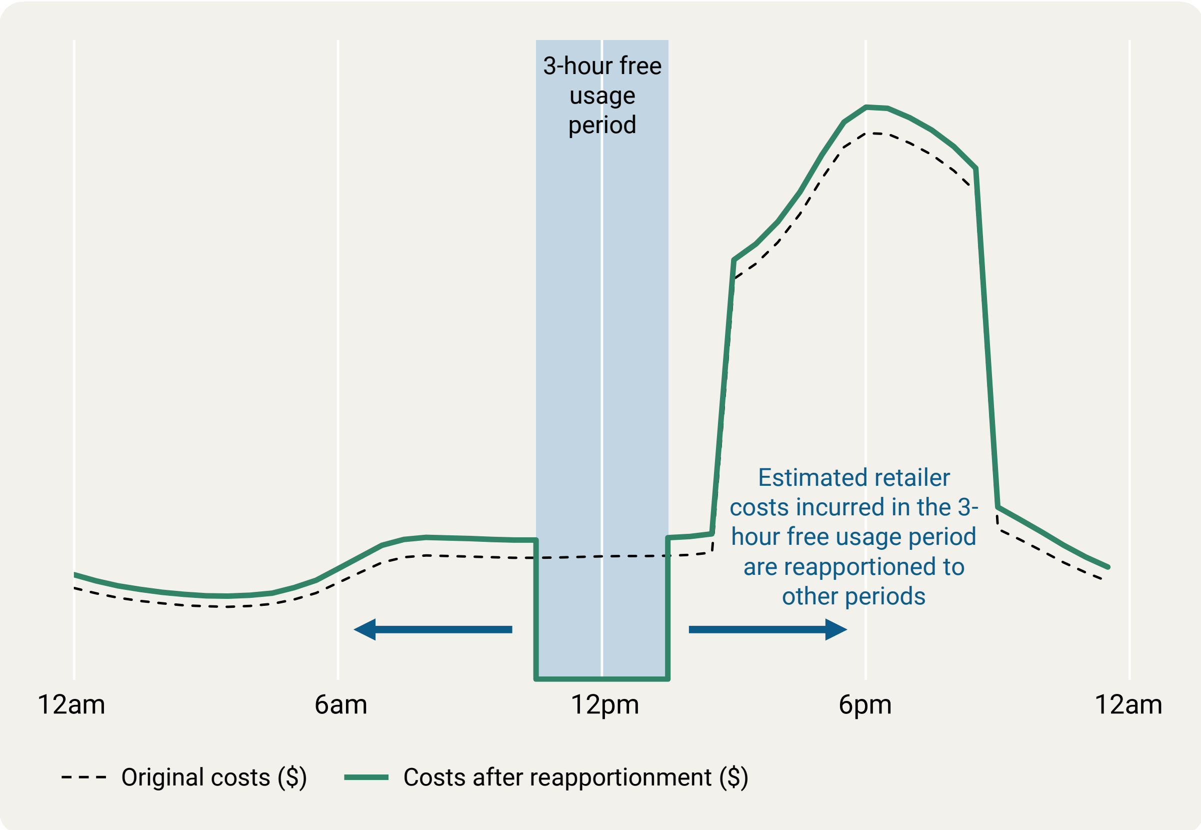
- **Wholesale costs:** time of use and other wholesale costs (chapter 4).
- **Network costs:** we have applied the default time of use network tariffs in all DMO regions except Ausgrid, where we have used the most common time of use network tariff (chapter 5).
- **Environmental costs:** identical to the time of use DMO (chapter 6).
- **Retail costs and margin:** all retail costs are fixed costs consistently captured within the daily supply charges of the time of use DMO and SSO tariffs (chapter 7). The retail margin has also been applied to the SSO (chapter 8).

We acknowledge views of the Queensland Electricity Users Network regarding retailer viability and the potential for retailers to recoup costs through non-DMO retail offers. We consider adopting the costs of the time of use DMO tariff for the SSO reflects retailers' efficient costs to supply and aims to limit the potential for retailers to recover SSO costs through non-DMO retail offers.

Retailers' recovery of costs incurred in the free usage period

As stakeholders highlighted, retailers will incur costs during the free usage period, including variable network, wholesale and environmental costs. To enable retailers to recover their efficient costs to supply customers on the SSO, we have estimated costs incurred during the free usage period using our pattern of supply and propose to reapportion them across non-free usage periods on a volume-weighted basis (Figure 10.4). This means estimated costs incurred during the free usage period are recovered through slightly higher usage charges in non-free usage periods.

Figure 10.4 Approach to cost reapportionment in the SSO



Under this approach, recoverable costs are reapportioned by the assumed volume of electricity consumed in each non-free usage period. This effectively increases the usage charges for all the non-free usage periods by the same amount. As a result, usage charges in the non-free usage periods of the SSO tariffs are 1–4 cents per kWh higher than the standard time of use DMO retail tariff rates, depending on the region.

We consider it is not appropriate to reapportion costs from the free usage period into the peak charge only. While it would strengthen the price signal to move consumption out of peak periods, it would limit the potential for retailers to recover costs if customers shift more usage than expected out of peak periods into the free usage period.

We acknowledge stakeholder views on allocating costs into the daily supply charge as a measure to ensure retailers can still recover costs from SSO customers who shift large portions of load. However, we consider it appropriate to maintain parity with the time of use

DMO tariff daily supply charges and instead facilitate cost recovery through the usage charges. Allocating recoverable costs to usage charges only will create stronger price signals for customers to shift load from non-free usage periods to the free usage period. Increasing the daily supply charge above cost reflectivity could produce adverse outcomes for customers with lower usage levels because they would be subject to a higher daily supply charge based on a higher amount of electricity than they are consuming. This then reduces the opportunity for these customers to experience bill savings because of shifting load.

Increasing the SSO daily supply charge would introduce an element of estimation into the DMO methodology because variable costs incurred would need to be reallocated as fixed costs. A decision on the portion of recoverable costs to allocate into the daily supply charge would also be arbitrary.

10.3.3 Reasonable use tariff cap

Our draft decision sets the reasonable use tariff cap for any electricity usage above the 24 kWh reasonable use cap at the corresponding off-peak or solar soak SSO tariff rate.

We currently do not have enough robust information to develop a new usage charge, so only considered existing usage charges within the SSO tariff. We consider that using the SSO usage charge for the tariff period that the free usage periods replaces (i.e., either off-peak or solar soak) would more accurately reflect the efficient costs incurred by retailers for supplying electricity to customers during the free usage period. A peak-based charge would introduce risk for households with exceptionally high usage, which may lead to them unintentionally breaching the cap upon shifting load and being exposed to high charges in the middle of the day as a result. Additionally, while we acknowledge a peak-based charge could act to disincentivise excessive consumption (a risk highlighted by retailers), we consider applying such a high charge would exceed the costs a retailer is expected to incur during the free usage period.

As a result, we propose the following SSO tariff rates would apply when a customer consumes more than 24 kWh during the free usage period on a given day:

- **Ausgrid:** SSO off-peak rate (28 cents per kWh)
- **Endeavour Energy:** SSO solar soak rate (14 cents per kWh)
- **Essential Energy:** SSO off-peak rate (27 cents per kWh)
- **Energex:** SSO off-peak rate (8 cents per kWh)
- **SA Power Networks:** SSO solar soak rate (20 cents per kWh).

10.3.4 Consumer behaviour

Our draft determination does not propose a bespoke SSO customer load profile nor assume any degree of customer load shifting or additional consumption for the first SSO.

Although the intent of the SSO is for customers to shift their consumption into the free usage period, we do not currently have enough robust information to make an adjustment to the assumed customer load profile with any accuracy. We observed varying outcomes in information received from retailers with free usage period plans. We will be in a better position to consider any assumptions once we have data on SSO customers' actual behaviour.

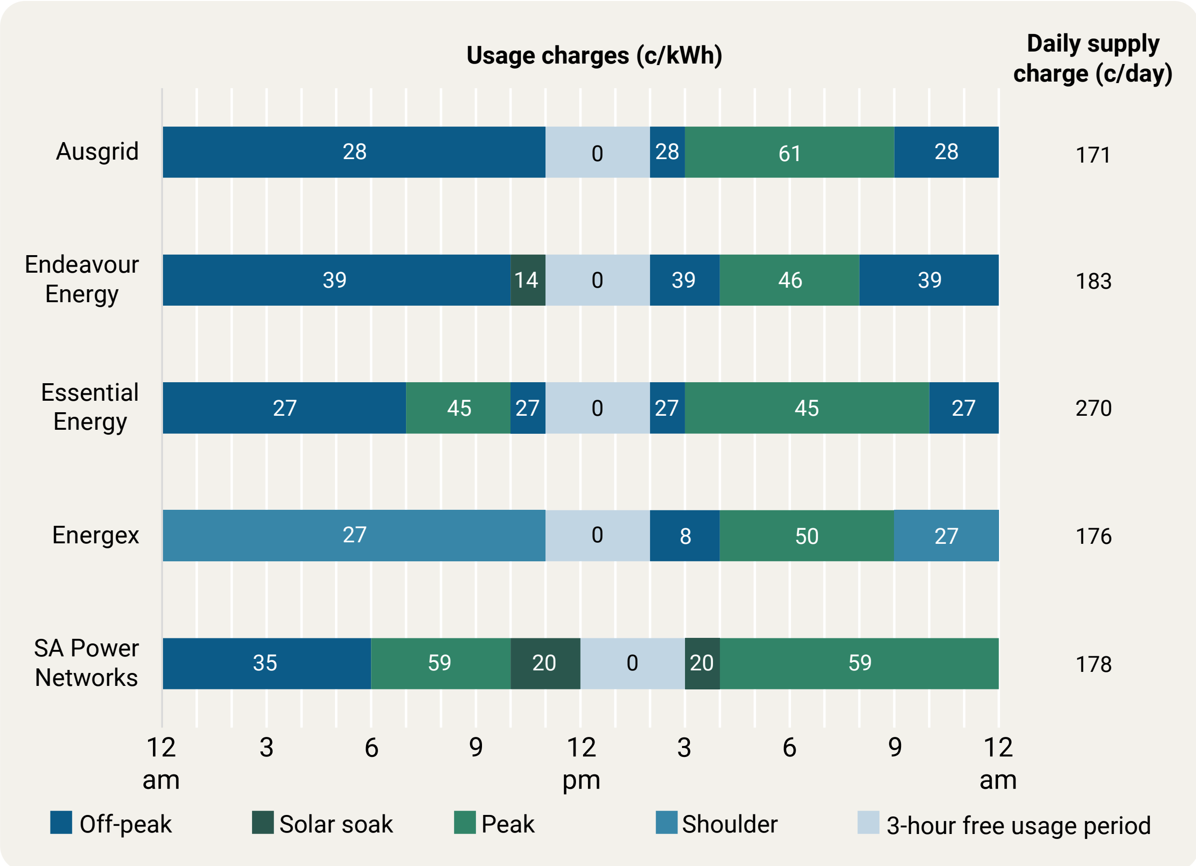
In the absence of robust evidence, we consider it appropriate to assume no load shifting behaviour because, by doing so, customers who do load shift will be better off.[304] Specifically, assuming no load shifting behaviour means that any customer who shifts some of their consumption into the free usage period will have lower electricity bills than if they did not shift load while on the standard time of use DMO standing offer.

We propose to base assumed SSO customer usage on the standard DMO 8 pattern of supply. We consider this to be a broadly representative starting point for overall residential customer usage (see chapter 9).

10.3.5 Draft SSO tariffs

Our draft SSO tariffs are shown in Figure 10.5.

Figure 10.5 Draft SSO tariff structure (local time), usage charges (c/kWh) and daily supply charges (c/day)



Note: Specific details of usage charges across different time of use windows are set out in the legislative instrument (Appendix C). Any usage in the 3-hour free usage period above the reasonable use cap (24 kWh) will be charged at the reasonable use tariff cap, which is the respective off-peak charge in Ausgrid, Essential Energy and Energex, and the respective solar soak charge in Endeavour Energy and SA Power Networks.

[304] Consistent with design principle 4.

11 Appendices

Appendix A – List of stakeholder submissions received from the DMO 8 issues paper

Appendix B – Smart meter costs

Appendix C – DMO Legislative Instrument 2026–2027

Appendix D – Time of use periods

Appendix E – DMO 7 to DMO 8 price movements

Appendix F – Year-on-year and methodological changes to annual prices

Appendix G – State-based summaries

A List of stakeholder submissions received from the DMO 8 issues paper

Following release of the DMO 8 issues paper on 5 November 2025, we invited stakeholder submissions on the issues paper. The following are the stakeholders who engaged with us in this process.

Government bodies

1. South Australian Department for Energy and Mining, *Submission to DMO 8 issues paper*, 12 December 2025

Industry associations

2. Australian Energy Council, *Submission to DMO 8 issues paper*, 26 November 2025
3. Shopping Centre Council of Australia, *Submission to DMO 8 issues paper*, 26 November 2025

Retailers

4. 1st Energy, *Submission to DMO 8 issues paper*, 28 November 2025
5. ActewAGL, *Submission to DMO 8 issues paper*, 26 November 2025
6. AGL, *Submission to DMO 8 issues paper*, 1 December 2025
7. Alinta Energy, *Submission to DMO 8 issues paper*, 28 November 2025
8. Altogether Group, *Submission to DMO 8 issues paper*, 26 November 2025
9. Energy On, *Submission to DMO 8 issues paper*, 26 November 2025
10. Energy Trade, *Submission to DMO 8 issues paper*, 27 November 2025
11. EnergyAustralia, *Submission to DMO 8 issues paper*, 28 November 2025
12. ENGIE, *Submission to DMO 8 issues paper*, 26 November 2025
13. GloBird Energy, *Submission to DMO 8 issues paper*, 26 November 2025
14. Origin Energy, *Submission to DMO 8 issues paper*, 1 December 2025
15. Powershop, *Submission to DMO 8 issues paper*, 28 November 2025

Consumer groups/representatives

16. Customer Consultative Group, *Submission to DMO 8 issues paper*, 19 November 2025
17. ECA, *Submission to DMO 8 issues paper*, 26 November 2025
18. Etrog Consulting, *Submission to DMO 8 issues paper*, 1 December 2025
19. JEC, *Submission to DMO 8 issues paper*, 1 December 2025
20. National Seniors Australia, *Submission to DMO 8 issues paper*, 26 November 2025
21. Nexa Advisory, *Submission to DMO 8 issues paper*, 2 December 2025
22. Queensland Electricity Users Network, *Submission to DMO 8 issues paper*, 1 December 2025
23. SACOSS, *Submission to DMO 8 issues paper*, 1 December 2025

Distribution network service providers

24. Ausgrid, *Submission to DMO 8 issues paper*, 1 December 2025

25. SA Power Networks, *Submission to DMO 8 issues paper*, 26 November 2025

Consumers

26. Dane Colson, *Submission to DMO 8 issues paper*, 15 November 2025

27. Treya Derrington, *Submission to DMO 8 issues paper*, 20 November 2025

B Smart meter costs

We requested retailers selling to approximately 98.9% of residential customers and 98.1% of small businesses in DMO regions to provide the number of customers on advanced meters and accumulation meters for each DMO region and customer type as at 30 June 2025, and projected installations for the mid-point of DMO 8 (31 December 2026). We also asked retailers to provide the annual costs they have incurred for customers with an advanced meter. Tables B.1 and B.2 set out our calculations for estimating advanced meter costs per residential and small business customer.

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

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Total advanced meter costs incurred by retailers (S)	$80,086,156	$77,038,790	$53,680,820	$83,214,657	$47,651,296
Total advanced meter customers	675,691	624,824	452,328	768,518	433,087
Average cost incurred per advanced meter ($) (ex. GST)	$118.52	$123.30	$118.68	$108.28	$110.03
ACS metering allowance included in network component ($) (ex. GST)	$28.54	N/A			
Proportion of customers that do not incur an ACS charge (new connections with smart meters)	7.83%	N/A			
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-$2.23	N/A			
Total customers	1,563,389	988,490	770,544	1,436,736	786,730
Customers with advanced meters (%)	43.22%	63.21%	58.70%	53.49%	55.05%
Advanced meter cost per customer ($)	$48.99	$77.94	$69.67	$57.92	$60.57
Additional capital allowance adjustment (see Table B.3)	$1.42	$1.35	$0.99	$1.08	$1.09

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

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Total advanced meter costs incurred by retailers (S)	$6,177,235	$4,796,519	$4,317,801	$6,030,259	$5,017,628
Total advanced meter customers	43,957	34,885	30,611	46,361	42,077
Average cost incurred per advanced meter ($) (ex. GST)	$140.53	$137.49	$141.05	$130.07	$119.25
ACS metering allowance included in network component ($) (ex. GST)	$39.54	N/A			
Proportion of customers that do not incur an ACS charge (new connections with smart meters)	23.10%	N/A			
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-$9.13	N/A			
Total customers	131,766	70,909	69,056	101,482	83,116
Customers with advanced meters (%)	33.36%	49.20%	44.33%	45.68%	50.62%
Advanced meter cost per customer ($)	$37.75	$67.64	$62.53	$59.42	$60.37
Additional capital allowance adjustment (see Table B.4)	$1.94	$1.06	$1.01	$1.88	$1.24

Table B.3 Calculation of residential capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 8, based on actual installations at 30 June 2025	$48.99	$77.94	$69.67	$57.92	$60.57
Smart meter allowance based on retailer projected installations at 31 December 2026	$63.18	$91.44	$79.56	$68.70	$71.49
Projected shortfall in smart meter allowance at 31 December 2026	$14.19	$13.50	$9.89	$10.78	$10.92
Weighted average cost of capital applied in shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (ex. GST)	$1.42	$1.35	$0.99	$1.08	$1.09

Table B.4 Calculation of small business capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 8, based on actual installations at 30 June 2025	$37.75	$67.64	$62.53	$59.42	$60.37
Smart meter allowance based on retailer projected installations at 31 December 2026	$57.15	$78.21	$72.58	$78.22	$72.77
Projected shortfall in smart meter allowance at 31 December 2026	$19.40	$10.56	$10.05	$18.79	$12.40
Weighted average cost of capital applied in shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (ex. GST)	$1.94	$1.06	$1.01	$1.88	$1.24

C DMO Legislative Instrument 2026–2027

Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2026

The Australian Energy Retailer makes the following determination.

Dated **DRAFT ONLY**

Name of maker **DRAFT ONLY—NOT FOR SIGNATURE**
Title of maker

1 Name

This instrument is the *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2026*.

2 Commencement

This instrument commences on 1 July 2026.

3 Authority

This instrument is made under sections 16(1), 16(1A), 18(1), and 18(4) of the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 as amended by the Competition and Consumer (Industry Code—Electricity Retail) Amendment Regulations 2026, and subsection 4(2) of the *Acts Interpretation Act 1901* (Cth) as applied by paragraph 13(1)(a) of the *Legislation Act 2003* (Cth).

4 Definitions

In this Determination:

annual usage means the amount determined by the AER in accordance with s 16(1)(a)(i) and 16(1A)(a)(i) of the Regulations, as a per-customer amount of electricity supplied in specified distribution regions to small customers; and

comparison price means a per-customer annual amount determined by the AER for electricity supplied as a non-regulated tariff under s16(1)(b) and for the regulated tariffs under s16(1A)(b) for small customers, derived by applying the annual usage and pattern of supply to the tariff cap; and

controlled load tariff means a tariff for supplying electricity to residential customers for use only in specific appliances and on separate circuits as referred to as the definition of regulated tariff in s5(e) of the Regulations; and

free usage period means a period determined by the AER under the SSO regulated tariff during which there is no variable charge for electricity used by the residential customer that does not exceed the reasonable use cap for the free usage period; and

non-regulated tariff means a tariff that is not regulated and for which the AER has determined a comparison price according to s16(1)(b) of the Regulations; and

pattern of supply means a representative consumption pattern determined by the AER for each distribution region and to small customers for non-regulated tariffs under s16(1)(a)(ii) and for regulated tariffs under s16(1A)(a)(ii); and

reasonable use tariff cap means the amount the AER must determine for a Solar Sharer Offer tariff for any electricity used in excess of the reasonable use cap in the free usage period see s18(3)–(4); and

regulated tariff means any of the types of tariffs listed in the definition of regulated tariffs in s5(a)–(f) of the Regulations for which the AER determines a comparison price and a tariff cap under s16(1A) of the Regulations; and

Regulations means the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 as amended by the Competition and Consumer (Industry Code—Electricity Retail) Amendment Regulations 2026; and

residential flat-rate tariff means a residential tariff for the supply of electricity referred to as a regulated tariff in s5(a) of the Regulations that does not vary according to time of day, the amount of supply, the temperature of other variable characteristics; and

residential time of use tariff means a tariff (other than a demand tariff), for supplying electricity, that varies (wholly or partly) according to the time of day when the electricity is supplied referred to as regulated tariff in s5(c) of the regulations for residential customers; and

small business flat-rate tariff means a residential tariff for the supply of electricity referred to as the definition of regulated tariff in s5(b) of the

Regulations that does not vary according to time of day, the amount of supply, the temperature of other variable characteristics; and

small business time of use tariff means a tariff (other than a demand tariff), for supplying electricity, that varies (wholly or partly) according to the time of day when the electricity is supplied referred to as regulated tariff in s5(d) of the regulations for small business customers; and

Solar Sharer Offer regulated tariff means a flexible tariff for residential customers that includes a free usage period and a reasonable use tariff cap referred to as the definition of regulated tariff in s5(f) of the Regulations; and

tariff cap means the amount of fixed charge and/or variable charges that an electricity retailer may charge small customers of that type in a distribution region in the year for supplying electricity under a regulated tariff of that type determined under s16(1A)(c); and

time of use controlled load tariff means a flexible tariff for supplying electricity to residential customers for use only in specific appliances and on separate circuits as referred to as the definition of regulated tariff in s5(e) of the Regulations; and

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

5 Per-customer annual usage determination

Per-customer annual usage determination (365 days p.a. in 2026-27) (kWh/p.a.)					
Distribution Region	**Annual Usage for residential flat rate, residential time of use, solar sharer offer and residential non-regulated tariffs**	**Annual Usage for small business flat rate, small business time of use, and small business non-regulated tariffs**	**Annual Usage for Residential Controlled Load 1, Residential Controlled Load 2 and Time of Use Controlled Load (SA Power Networks)**	**Annual Usage for Residential Controlled Load 1 + 2 (kWh/p.a.)**	
				Controlled Load 1	Controlled Load 2
Ausgrid	3,900	10,000	2,000	1,340	660
Endeavour Energy	4,900	10,000	2,200	1,474	726
Energex	4,600	10,000	1,900	551	1,349
Essential Energy	4,600	10,000	2,000	1,540	460
SA Power Networks	4,000	10,000	1,800	1,800	-

6 Pattern of supply determination

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

(1) Seasonality assumptions, all tariff and customer types

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

(2) Pattern of supply for

(a) Ausgrid distribution region

(i) Pattern of supply for comparison prices for residential flat-rate, residential time of use, residential Solar Sharer Offer and residential non regulated tariffs

Time	**00:00 - 00:30**	**00:30 - 01:00**	**01:00 - 01:30**	**01:30 - 02:00**	**02:00 - 02:30**	**02:30 - 03:00**	**03:00 - 03:30**	**03:30 - 04:00**	**04:00 - 04:30**	**04:30 - 05:00**	**05:00 - 05:30**	**05:30 - 06:00**	**06:00 - 06:30**	**06:30 - 07:00**	**07:00 - 07:30**	**07:30 - 08:00**	**08:00 - 08:30**	**08:30 - 09:00**	**09:00 - 09:30**	**09:30 - 10:00**	**10:00 - 10:30**	**10:30 - 11:00**	**11:00 - 11:30**	**11:30 - 12:00**
Usage (kWh)	**0.1692**	**0.1590**	**0.1512**	**0.1451**	**0.1405**	**0.1371**	**0.1351**	**0.1342**	**0.1358**	**0.1393**	**0.1480**	**0.1599**	**0.1785**	**0.1976**	**0.2165**	**0.2261**	**0.2295**	**0.2284**	**0.2274**	**0.2262**	**0.2251**	**0.2251**	**0.2255**	**0.2264**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2276**	**0.2282**	**0.2285**	**0.2290**	**0.2306**	**0.2349**	**0.2410**	**0.2501**	**0.2628**	**0.2799**	**0.3013**	**0.3202**	**0.3286**	**0.3281**	**0.3226**	**0.3155**	**0.3061**	**0.2935**	**0.2782**	**0.2586**	**0.2378**	**0.2164**	**0.1976**	**0.1814**

(ii) Pattern of supply for comparison prices for small business flat-rate, small business time of use, and small business non-regulated tariffs

Time	**00:00 - 00:30**	**00:30 - 01:00**	**01:00 - 01:30**	**01:30 - 02:00**	**02:00 - 02:30**	**02:30 - 03:00**	**03:00 - 03:30**	**03:30 - 04:00**	**04:00 - 04:30**	**04:30 - 05:00**	**05:00 - 05:30**	**05:30 - 06:00**	**06:00 - 06:30**	**06:30 - 07:00**	**07:00 - 07:30**	**07:30 - 08:00**	**08:00 - 08:30**	**08:30 - 09:00**	**09:00 - 09:30**	**09:30 - 10:00**	**10:00 - 10:30**	**10:30 - 11:00**	**11:00 - 11:30**	**11:30 - 12:00**
Usage (kWh)	**0.3472**	**0.3427**	**0.3397**	**0.3374**	**0.3361**	**0.3352**	**0.3364**	**0.3386**	**0.3461**	**0.3570**	**0.3788**	**0.4060**	**0.4535**	**0.5029**	**0.5721**	**0.6406**	**0.7148**	**0.7678**	**0.8144**	**0.8372**	**0.8556**	**0.8622**	**0.8654**	**0.8631**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.8609**	**0.8555**	**0.8489**	**0.8367**	**0.8193**	**0.7975**	**0.7698**	**0.7403**	**0.6967**	**0.6567**	**0.6167**	**0.5876**	**0.5603**	**0.5412**	**0.5224**	**0.5032**	**0.4789**	**0.4539**	**0.4269**	**0.4037**	**0.3847**	**0.3711**	**0.3608**	**0.3529**

(b) Endeavour Energy distribution region

(i) Pattern of supply for comparison prices for residential flat rate, residential time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2008**	**0.1867**	**0.1760**	**0.1677**	**0.1620**	**0.1578**	**0.1561**	**0.1561**	**0.1600**	**0.1660**	**0.1787**	**0.1949**	**0.2193**	**0.2440**	**0.2681**	**0.2793**	**0.2819**	**0.2788**	**0.2776**	**0.2768**	**0.2764**	**0.2775**	**0.2797**	**0.2832**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2878**	**0.2921**	**0.2967**	**0.3010**	**0.3081**	**0.3177**	**0.3288**	**0.3425**	**0.3584**	**0.3780**	**0.4007**	**0.4186**	**0.4229**	**0.4185**	**0.4096**	**0.4003**	**0.3870**	**0.3694**	**0.3469**	**0.3206**	**0.2920**	**0.2642**	**0.2395**	**0.2180**

(ii) Pattern of supply for comparison prices for small business flat-rate, small business time of use, and small business non-regulated tariffs

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.3743**	**0.3689**	**0.3661**	**0.3632**	**0.3618**	**0.3613**	**0.3644**	**0.3692**	**0.3800**	**0.3932**	**0.4190**	**0.4455**	**0.4917**	**0.5351**	**0.5957**	**0.6471**	**0.7026**	**0.7413**	**0.7739**	**0.7907**	**0.8033**	**0.8093**	**0.8110**	**0.8091**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.8065**	**0.8025**	**0.7973**	**0.7881**	**0.7721**	**0.7518**	**0.7251**	**0.6972**	**0.6612**	**0.6296**	**0.6040**	**0.5884**	**0.5739**	**0.5625**	**0.5484**	**0.5316**	**0.5073**	**0.4844**	**0.4590**	**0.4377**	**0.4173**	**0.4027**	**0.3902**	**0.3807**

(c) Energex distribution region

(i) Pattern of supply for comparison prices for residential flat rate, residential time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	**00:00 - 00:30**	**00:30 - 01:00**	**01:00 - 01:30**	**01:30 - 02:00**	**02:00 - 02:30**	**02:30 - 03:00**	**03:00 - 03:30**	**03:30 - 04:00**	**04:00 - 04:30**	**04:30 - 05:00**	**05:00 - 05:30**	**05:30 - 06:00**	**06:00 - 06:30**	**06:30 - 07:00**	**07:00 - 07:30**	**07:30 - 08:00**	**08:00 - 08:30**	**08:30 - 09:00**	**09:00 - 09:30**	**09:30 - 10:00**	**10:00 - 10:30**	**10:30 - 11:00**	**11:00 - 11:30**	**11:30 - 12:00**
Usage (kWh)	**0.1860**	**0.1749**	**0.1666**	**0.1599**	**0.1550**	**0.1512**	**0.1489**	**0.1478**	**0.1497**	**0.1538**	**0.1632**	**0.1756**	**0.1967**	**0.2211**	**0.2446**	**0.2561**	**0.2622**	**0.2642**	**0.2682**	**0.2708**	**0.2729**	**0.2753**	**0.2781**	**0.2830**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2875**	**0.2918**	**0.2966**	**0.2995**	**0.3026**	**0.3051**	**0.3107**	**0.3197**	**0.3286**	**0.3426**	**0.3633**	**0.3872**	**0.3991**	**0.3974**	**0.3851**	**0.3687**	**0.3498**	**0.3306**	**0.3099**	**0.2865**	**0.2614**	**0.2378**	**0.2167**	**0.1991**

(ii) Pattern of supply for comparison prices for small business flat-rate, small business time of use, and small business non-regulated tariffs

Time	**00:00 - 00:30**	**00:30 - 01:00**	**01:00 - 01:30**	**01:30 - 02:00**	**02:00 - 02:30**	**02:30 - 03:00**	**03:00 - 03:30**	**03:30 - 04:00**	**04:00 - 04:30**	**04:30 - 05:00**	**05:00 - 05:30**	**05:30 - 06:00**	**06:00 - 06:30**	**06:30 - 07:00**	**07:00 - 07:30**	**07:30 - 08:00**	**08:00 - 08:30**	**08:30 - 09:00**	**09:00 - 09:30**	**09:30 - 10:00**	**10:00 - 10:30**	**10:30 - 11:00**	**11:00 - 11:30**	**11:30 - 12:00**
Usage (kWh)	**0.3540**	**0.3485**	**0.3447**	**0.3413**	**0.3388**	**0.3373**	**0.3379**	**0.3395**	**0.3454**	**0.3568**	**0.3818**	**0.4133**	**0.4657**	**0.5137**	**0.5758**	**0.6351**	**0.6982**	**0.7468**	**0.7844**	**0.8062**	**0.8277**	**0.8437**	**0.8550**	**0.8592**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.8595**	**0.8560**	**0.8518**	**0.8419**	**0.8242**	**0.7996**	**0.7698**	**0.7387**	**0.6983**	**0.6601**	**0.6126**	**0.5800**	**0.5548**	**0.5405**	**0.5255**	**0.5088**	**0.4888**	**0.4668**	**0.4401**	**0.4173**	**0.3973**	**0.3820**	**0.3706**	**0.3616**

(d) Essential Energy distribution region

(i) Pattern of supply for comparison prices for residential flat rate, residential time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	**00:00 - 00:30**	**00:30 - 01:00**	**01:00 - 01:30**	**01:30 - 02:00**	**02:00 - 02:30**	**02:30 - 03:00**	**03:00 - 03:30**	**03:30 - 04:00**	**04:00 - 04:30**	**04:30 - 05:00**	**05:00 - 05:30**	**05:30 - 06:00**	**06:00 - 06:30**	**06:30 - 07:00**	**07:00 - 07:30**	**07:30 - 08:00**	**08:00 - 08:30**	**08:30 - 09:00**	**09:00 - 09:30**	**09:30 - 10:00**	**10:00 - 10:30**	**10:30 - 11:00**	**11:00 - 11:30**	**11:30 - 12:00**
Usage (kWh)	**0.1860**	**0.1773**	**0.1714**	**0.1668**	**0.1640**	**0.1618**	**0.1615**	**0.1625**	**0.1674**	**0.1745**	**0.1888**	**0.2071**	**0.2331**	**0.2574**	**0.2783**	**0.2850**	**0.2821**	**0.2736**	**0.2677**	**0.2623**	**0.2592**	**0.2574**	**0.2579**	**0.2591**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2619**	**0.2637**	**0.2657**	**0.2678**	**0.2717**	**0.2785**	**0.2884**	**0.3023**	**0.3217**	**0.3472**	**0.3769**	**0.4016**	**0.4086**	**0.3994**	**0.3829**	**0.3656**	**0.3461**	**0.3236**	**0.2989**	**0.2720**	**0.2538**	**0.2292**	**0.2149**	**0.1981**

(ii) Pattern of supply for comparison prices for small business flat-rate, small business time of use, and small business non regulated tariffs

Time	**00:00 - 00:30**	**00:30 - 01:00**	**01:00 - 01:30**	**01:30 - 02:00**	**02:00 - 02:30**	**02:30 - 03:00**	**03:00 - 03:30**	**03:30 - 04:00**	**04:00 - 04:30**	**04:30 - 05:00**	**05:00 - 05:30**	**05:30 - 06:00**	**06:00 - 06:30**	**06:30 - 07:00**	**07:00 - 07:30**	**07:30 - 08:00**	**08:00 - 08:30**	**08:30 - 09:00**	**09:00 - 09:30**	**09:30 - 10:00**	**10:00 - 10:30**	**10:30 - 11:00**	**11:00 - 11:30**	**11:30 - 12:00**
Usage (kWh)	**0.4230**	**0.4189**	**0.4153**	**0.4114**	**0.4088**	**0.4069**	**0.4079**	**0.4097**	**0.4176**	**0.4274**	**0.4467**	**0.4684**	**0.5046**	**0.5420**	**0.5910**	**0.6368**	**0.6846**	**0.7177**	**0.7421**	**0.7527**	**0.7600**	**0.7645**	**0.7648**	**0.7618**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.7580**	**0.7545**	**0.7491**	**0.7408**	**0.7285**	**0.7133**	**0.6931**	**0.6723**	**0.6370**	**0.6086**	**0.5845**	**0.5724**	**0.5629**	**0.5539**	**0.5425**	**0.5281**	**0.5117**	**0.4944**	**0.4806**	**0.4657**	**0.4547**	**0.4432**	**0.4353**	**0.4278**

(e) SA Power Networks distribution region

(i) Pattern of supply for comparison prices for residential flat rate, residential time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	0.2208	0.2731	0.2689	0.2472	0.2191	0.1887	0.1697	0.1568	0.1496	0.1441	0.1425	0.1478	0.1575	0.1777	0.1684	0.1826	0.1913	0.1929	0.1910	0.1924	0.2391	0.2684	0.2723	0.2694
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	0.2566	0.2510	0.2415	0.2367	0.2350	0.2394	0.2425	0.2494	0.2398	0.2558	0.2752	0.2963	0.3139	0.3193	0.3135	0.3029	0.2922	0.2804	0.2652	0.2462	0.2247	0.2019	0.1810	0.1671

(ii) Pattern of supply for comparison prices for small business flat-rate, small business time of use, and small business non regulated tariffs

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.5008**	**0.5804**	**0.5732**	**0.5434**	**0.5003**	**0.4518**	**0.4207**	**0.3998**	**0.3883**	**0.3793**	**0.3767**	**0.3892**	**0.4101**	**0.4555**	**0.4549**	**0.4968**	**0.5287**	**0.5497**	**0.5598**	**0.5716**	**0.6624**	**0.7146**	**0.7223**	**0.7178**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.6943**	**0.6879**	**0.6685**	**0.6578**	**0.6518**	**0.6523**	**0.6513**	**0.6535**	**0.6257**	**0.6375**	**0.6568**	**0.6809**	**0.7048**	**0.7112**	**0.6994**	**0.6790**	**0.6570**	**0.6334**	**0.6029**	**0.5666**	**0.5263**	**0.4844**	**0.4461**	**0.4200**

(iii) Pattern of supply for comparison prices for Time of Use controlled load

Time	**00:00 - 00:30**	**00:30 - 01:00**	**01:00 - 01:30**	**01:30 - 02:00**	**02:00 - 02:30**	**02:30 - 03:00**	**03:00 - 03:30**	**03:30 - 04:00**	**04:00 - 04:30**	**04:30 - 05:00**	**05:00 - 05:30**	**05:30 - 06:00**	**06:00 - 06:30**	**06:30 - 07:00**	**07:00 - 07:30**	**07:30 - 08:00**	**08:00 - 08:30**	**08:30 - 09:00**	**09:00 - 09:30**	**09:30 - 10:00**	**10:00 - 10:30**	**10:30 - 11:00**	**11:00 - 11:30**	**11:30 - 12:00**
Usage (kWh)	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.2057**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.1465**	**0.1465**	**0.1465**	**0.1465**	**0.1465**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.1465**	**0.1465**	**0.1465**	**0.1465**	**0.1465**	**0.1465**	**0.1465**	**0.1465**	**0.1465**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.2057**

7 Per-customer annual price determination for non-regulated tariff(s)

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

Per-customer draft comparison price determination non-regulated tariffs (all prices GST-inclusive)

Distribution region	Residential Annual Price ($)	Small Business Annual Price ($)
Ausgrid	1,886	4,598
Endeavour Energy	2,353	4,396
Energex	1,927	3,744
Essential Energy	2,515	4,902
SA Power Networks	2,270	4,696

8 Per-customer comparison price determination for regulated tariffs

In accordance with s 16(1A)(b) of the Regulations, the AER determines what it considers the reasonable per-customer annual price under a regulated tariff of that type for supplying electricity in specified distribution regions to small customers of that type. These are set out below.

Per-customer draft comparison price determination regulated tariffs (all prices GST-inclusive) ($/year)

Distribution region	Flat Rate Annual Residential	Flat Rate Annual Small Business	Time of use Annual Residential	Time of Use Annual Small Business	Controlled Load Annual Residential ($)				SSO Annual Residential
					CL 1	CL 2	CL 1 +2	TOU CL	
Ausgrid	1,875	4,474	1,886	4,598	400	467	432	-	1,886
Endeavour Energy	2,347	4,367	2,353	4,396	490	501	516	-	2,353
Energex	1,927	3,744	1,927	3,744	317	324	322	-	1,927
Essential Energy	2,515	4,902	2,515	4,902	437	486	468	-	2,515
SA Power Networks	2,270	4,696	2,270	4,696	405	-	-	411	2,270

9 Tariff cap price determination for regulated tariffs

In accordance with s 16(1A)(c) of the Regulations, the AER determines a tariff cap that is a maximum amount of fixed charge and variable charges under a regulated tariff of that type that an electricity retailer may charge small customers of that type in that distribution region of that type. These are set out below.

(1) Flat Rate Tariff Cap

Per-customer draft flat rate tariff cap price determination (all prices GST-inclusive)

Distribution Region	Customer type	Supply charge (c/day)	Usage charge (c/kWh)
Ausgrid	Residential	154.8504	33.5724
	Small business	364.9315	31.4239
Endeavour Energy	Residential	183.1892	34.2593
	Small business	242.8166	34.8065
Energex	Residential	175.9451	27.9410
	Small business	260.3105	27.9416
Essential Energy	Residential	270.3865	33.2297
	Small business	404.0629	34.2695
SA Power Networks	Residential	178.3462	40.4665
	Small business	183.7205	40.2516

(2) Residential Customers Time of Use Tariff Cap

Residential per-customer draft flexible tariff cap price determination (all prices GST-inclusive)

Distribution Region	Supply charge (c/day)	Usage charges (c/kWh)					
		Peak	Off-peak	Shoulder	High season peak	Low season peak	Solar Soak/Sponge
Ausgrid	171.1037	3pm-9pm (Nov-March; June-August) 57.8115	All hours outside peak (including all day Apr, May, Sep, Oct) 24.4435	-	-	-	-
Endeavour Energy	183.1892	-	All other times (8pm-10am; 2pm-4pm) 36.7549	-	4pm-8pm (Nov-March) 45.1174	4pm-8pm (April-Oct) 44.0999	10am-2pm 11.9536
Energex	175.9451	4pm-9pm 48.4199	11am-4pm 7.1554	9pm-11am 25.7711	-	-	-
Essential Energy	270.3865	7am-10am; 3pm-10pm 41.8956	All other times (10am-3pm; 10pm-7am) 24.0459	-	-	-	-
SA Power Networks	178.3462	6am-10am; 4pm-12am 56.1407	12am-6am 32.5237	-	-	-	10am-4pm 17.2312

Note: all times are shown in their local time for both daylight saving and standard time. Endeavour Energy Residential Time of Use Tariff Cap has a “Solar Soak” period. SA Power Networks Residential Time of Use Tariff Cap has a “Solar Sponge” period.

(3) Small Business Customers Time of Use Tariff Cap

Small business per-customer draft flexible tariff cap price determination (all prices GST-inclusive)

Distribution Region	Supply charge (c/day)	Usage charges (c/kWh)					
		Peak	Off-peak	Shoulder	High season peak	Low season peak	Solar Soak
Ausgrid	375.9369	3pm-9pm (Nov-March; June-August) 64.1986	All hours outside peak (including all day Apr, May, Sep, Oct) 25.4342	-	-	-	-
Endeavour Energy	242.8166	-	All other times (8pm-10am; 2pm-4pm) 39.9118	-	4pm-8pm Nov-March 48.2743	4pm-8pm April- Oct 47.2568	10am-2pm 13.6978
Energex	260.3105	5pm-8pm (M-F) 57.9943	11am-1pm 8.9033	All other times (8pm-11am; 1pm-5pm M-F; 1pm-11am S-S) 27.5092	-	-	-
Essential Energy	404.0629	7am-10am; 3pm-10pm 43.4460	All other times (10am-3pm, 10pm-7am) 27.0834	-	-	-	-
SA Power Networks	183.7205	5pm-9pm (Nov-Mar) 75.5127	9pm-7am (M-F); 9am-5pm (S-S Nov-Mar); all day (S-S Apr-Oct) 34.8686	7am-5pm (M-F Nov-Mar); 7am-9pm (M-F Apr-Oct) 43.6254	-	-	-

Note: all times are shown in their local time for both daylight saving and standard time.

(4) Controlled Load Tariff Cap for Residential Customers

Distribution Region	Regulated tariff	Charging components							
		Controlled load 1		Controlled load 2		TOU CL			
		Supply charge (c/day)	Usage charge (c/kWh)	Supply charge	Usage charge (c/kWh)	Supply charge (c/day)	Peak (6.30-9.30; 4.30-11.30) (c/kWh)	Off peak (11.30-6.30) (c/kWh)	Solar Sponge (9.30-4.30) (c/kWh)
Ausgrid	Controlled Load 1	3.4100	19.3660	-	-	-	-	-	-
	Controlled Load 2	-	-	2.5873	22.8592	-	-	-	-
	Controlled Load 1 and 2	3.4100	19.3660	2.5873	22.8592	-	-	-	-
Endeavour Energy	Controlled Load 1	9.3390	20.7130	-	-	-	-	-	-
	Controlled Load 2	-	-	4.5998	22.0165	-	-	-	-
	Controlled Load 1 and 2	9.3390	20.7130	4.5998	22.0165	-	-	-	-
Essential Energy	Controlled Load 1	12.0802	19.6228	-	-	-	-	-	-
	Controlled Load 2	-	-	3.6084	23.6637	-	-	-	-
	Controlled Load 1 and 2	12.0802	19.6228	3.6084	23.6637	-	-	-	-
Energex	Controlled Load 1	0.000	16.7080	-	-	-	-	-	-
	Controlled Load 2	-	-	0.000	17.0615	-	-	-	-
	Controlled Load 1 and 2	0.000	16.7080	0.000	17.0615	-	-	-	-
SA Power Networks	Controlled Load 1	0.000	22.4896	-	-	-	-	-	-
	Time of Use Controlled Load	-	-	-	-	0.000	38.1119	25.4502	19.1194

Note: all times are shown in their local time for both daylight saving and standard time.

(5) Solar Sharer Offer Tariff for Residential Customers

<table>
<tr><th colspan="6">Residential per-customer draft flexible tariff cap price determination (all prices GST-inclusive)</th></tr>
<tr><th rowspan="2">Distribution Region</th><th rowspan="2">Supply charge (c/day)</th><th colspan="4">Usage charges (c/kWh)</th></tr>
<tr><th>Peak</th><th>Off-peak</th><th>Shoulder</th><th>Solar Soak/Sponge</th></tr>
<tr><td>Ausgrid</td><td>171.1037</td><td>3pm-9pm
(Nov-March; June-August)
61.3919</td><td>9pm-11am;
2pm-3pm (Nov-March; June-August)
2pm-11am (Apr, May, Sep, Oct)
28.0239</td><td>-</td><td>-</td></tr>
<tr><td>Endeavour</td><td>183.1892</td><td>4pm-8pm
46.3190</td><td>8pm-10am
38.5356</td><td>-</td><td>10am-11am
13.7342</td></tr>
<tr><td>Energex</td><td>175.9451</td><td>4pm-9pm
49.5634</td><td>2pm-4pm
8.2989</td><td>9pm-11am
26.9146</td><td>-</td></tr>
<tr><td>Essential Energy</td><td>270.3865</td><td>7am-10am;
3pm-10pm
45.3325</td><td>10pm-7am;
10am-11am;
2pm-3pm
27.4827</td><td>-</td><td>-</td></tr>
<tr><td>SA Power Networks</td><td>178.3462</td><td>6am-10am;
4pm-12am
58.7898</td><td>12am-6am
35.1728</td><td>-</td><td>10am-12pm;
3pm-4pm
19.8803</td></tr>
</table>

Note: all times are shown in their local time for both daylight saving and standard time. Endeavour Energy Residential Solar Sharer Offer Tariff Cap has a “Solar Soak” period. SA Power Networks Residential Solar Sharer Offer Tariff Cap has a “Solar Sponge” period.

10 Free Usage Period for SSO regulated tariffs

Distribution region	SSO free usage period
Ausgrid	11am-2pm local time
Endeavour Energy	11am-2pm local time
Energex	11am-2pm local time
Essential Energy	11am-2pm local time
SA Power Networks	12pm-3pm local time

11 Reasonable Use Tariff Cap for SSO regulated tariffs

Distribution region	Reasonable use tariff (c/kWh)
Ausgrid	28.0239
Endeavour Energy	13.7342
Energex	8.2989
Essential Energy	27.4827
SA Power Networks	19.8803

D Time of use periods

The time of use wholesale energy costs and network costs in this draft determination reflect the default time of use network tariff in all regions, except for Ausgrid where the most common time of use network tariff has been used. The start and end times for these periods can be found in the table below, while cost inputs for each period can be found in the cost-assessment model published alongside this draft determination.

Table D.1 Start and end times for time of use periods in each region

<table>
<tr><th>Distribution region</th><th>Customer type</th><th>Time of use period</th><th>Start and end time</th></tr>
<tr><td rowspan="2">Ausgrid (NSW)</td><td rowspan="2">Residential, small business</td><td>Off-peak</td><td>All times outside of peak, including all day April, May, September, October</td></tr>
<tr><td>Peak</td><td>3pm until 9pm
November – March
June – August</td></tr>
<tr><td rowspan="4">Endeavour Energy (NSW)</td><td rowspan="4">Residential, small business</td><td>High season peak</td><td>4pm until 8pm
November – March</td></tr>
<tr><td>Low season peak</td><td>4pm until 8pm
April – October</td></tr>
<tr><td>Off-peak</td><td>8pm until 10am
2pm until 4pm</td></tr>
<tr><td>Solar soak</td><td>10am until 2pm</td></tr>
<tr><td rowspan="2">Essential Energy (NSW)</td><td rowspan="2">Residential, small business</td><td>Off-peak</td><td>10am until 3pm, 10pm until 7am</td></tr>
<tr><td>Peak</td><td>7am until 10am, 3pm until 10pm</td></tr>
</table>

Distribution region	Customer type	Time of use period	Start and end time
Energex (SE Queensland)	Residential	Off-peak	11am until 4pm
		Peak	4pm until 9pm
		Shoulder	9pm until 11am
	Small business	Off-peak	11am until 1pm
		Peak	5pm until 8pm – Monday to Friday
		Shoulder	8pm until 11am and 1pm until 5pm – Monday to Friday 1pm until 11am – Saturday to Sunday
SA Power Networks (South Australia)	Residential	Off-peak	12am until 6am
		Peak	6am until 10am, 4pm until 12am
		Solar sponge	10am – 4pm
	Small business	Off-peak	9pm until 7am – Monday to Friday, 9am until 5pm weekends, November to March. All day Weekends April to October
		Peak	5pm until 9pm, November to March
		Shoulder	7am until 5pm – Monday to Friday, November to March. 7am until 9pm – Monday to Friday, April to October.

E DMO 7 to DMO 8 price movements

The charts in this appendix show the movement in the DMO cost components between DMO 7 and the DMO 8 draft determination, with the overall height indicating the total DMO price for each DMO region.

We note that:

- Changes to the wholesale cost component reflect both year-on-year movement and also the impact of the methodological adjustments such as adopting the 50th percentile wholesale energy cost (WEC) estimate and applying a volatility allowance.
- For Network costs the lowest applicable network tariff for the DMO comparison price was applied which can be flat rate or time of use tariff. In some cases, this led to a reduction in the network cost component even though underlying network prices are rising.
- Environmental cost components in the DMO 8 draft determination are calculated using the same methodology as DMO 7, so the changes directly reflect year-on-year movement.
- Changes to the retail cost component reflect both year-on-year movement as well as methodological changes. This year we continued to collect data from retailers that covers 99% of the small customer market.
- Retail margin has been aligned to 6% for both residential and small business customers to reflect efficient costs to supply electricity to customers on standing offers.

Figure E.1 Residential flat rate percentage change from DMO 7 (nominal)

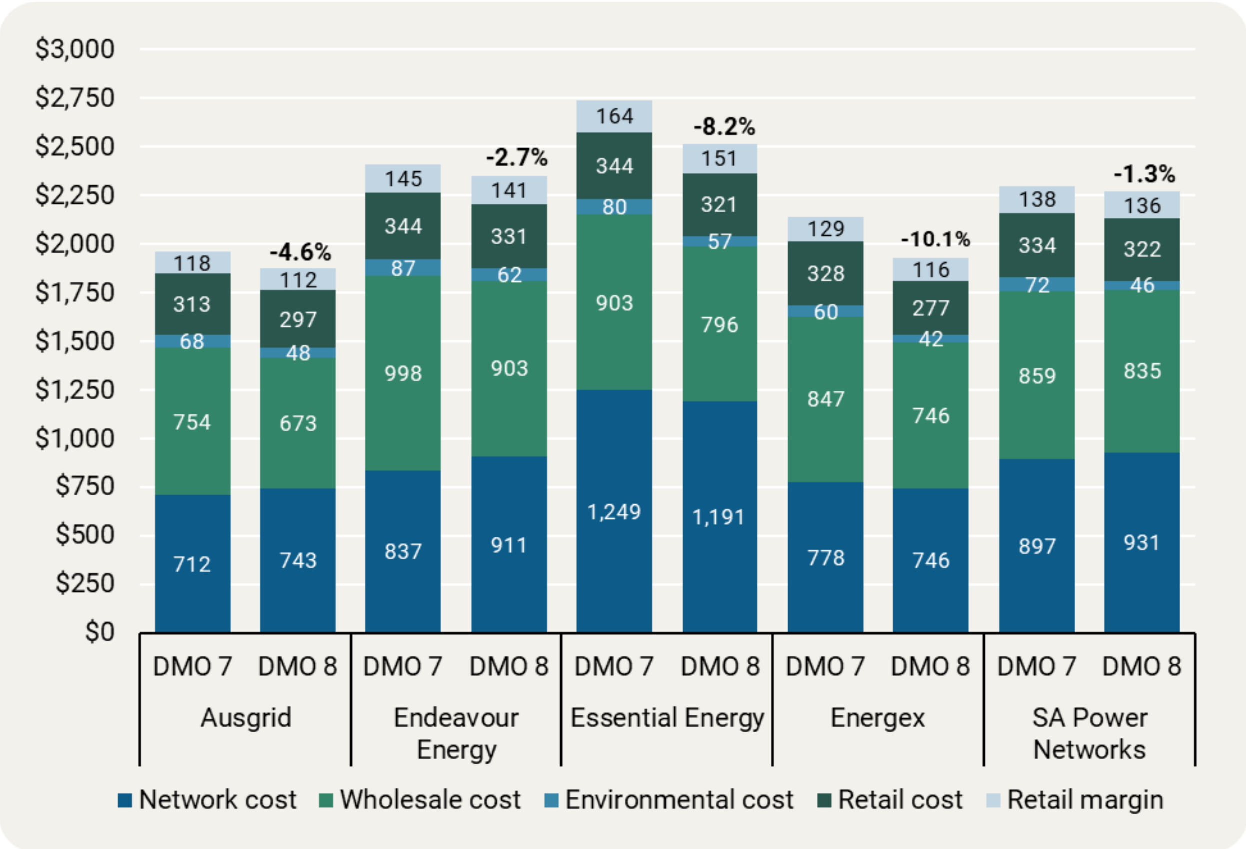
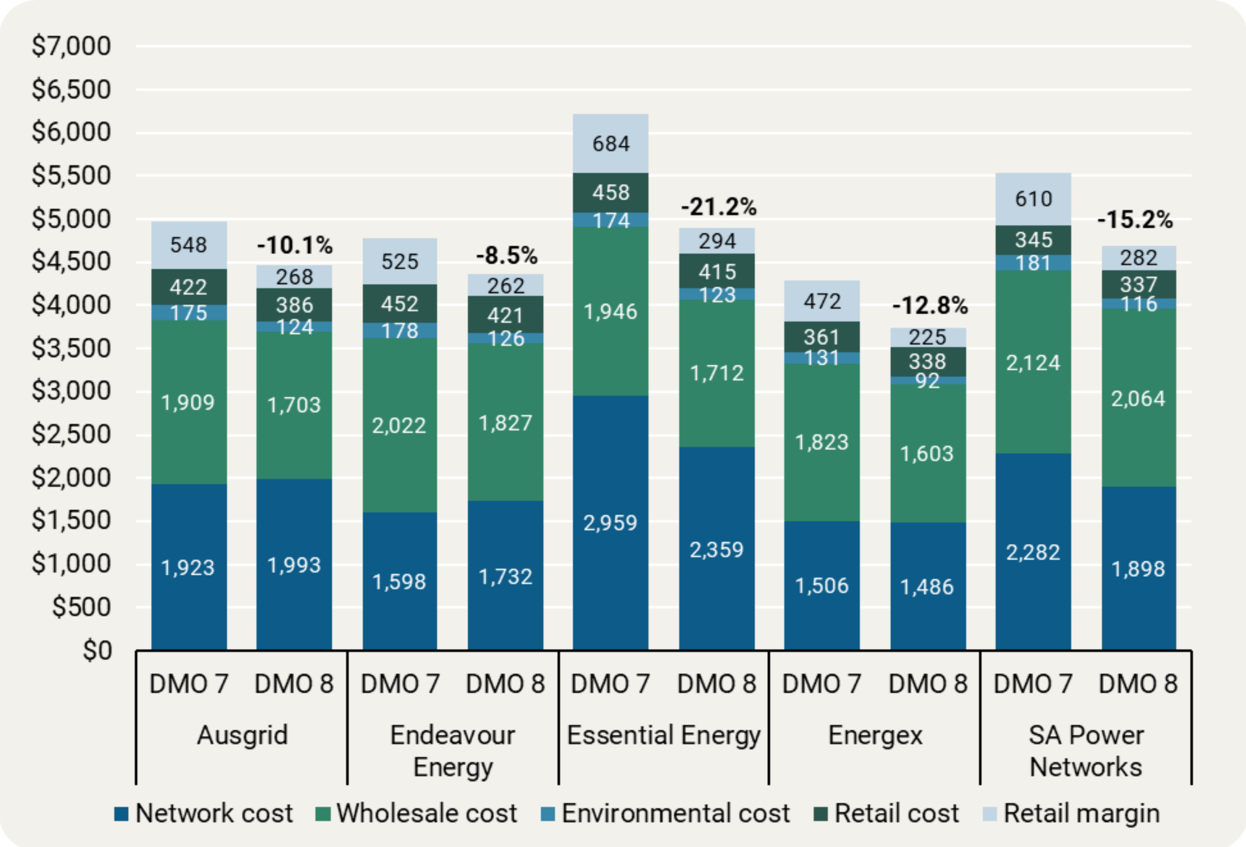


Figure E.2 Small business flat rate percentage change from DMO 7 (nominal)



F Year-on-year and methodological changes to annual prices

The charts in this appendix show the year-on-year changes (due to underlying changes in market conditions) as well as the changes resulting from movements in the DMO methodology.

For all figures movements in the CPI adjustment in the 'Methodology changes' section is a result of methodology changes to retail operating costs. Changes in the retail margin and other changes in the 'Methodology changes' section reduced cost components. Year-on-year changes in bad debt are a comparison of 2024–25 actual written off debt and 2023–24 expenses due to provision for bad and doubtful debt which was used in DMO 7.

Figure F.1 Ausgrid residential flat rate

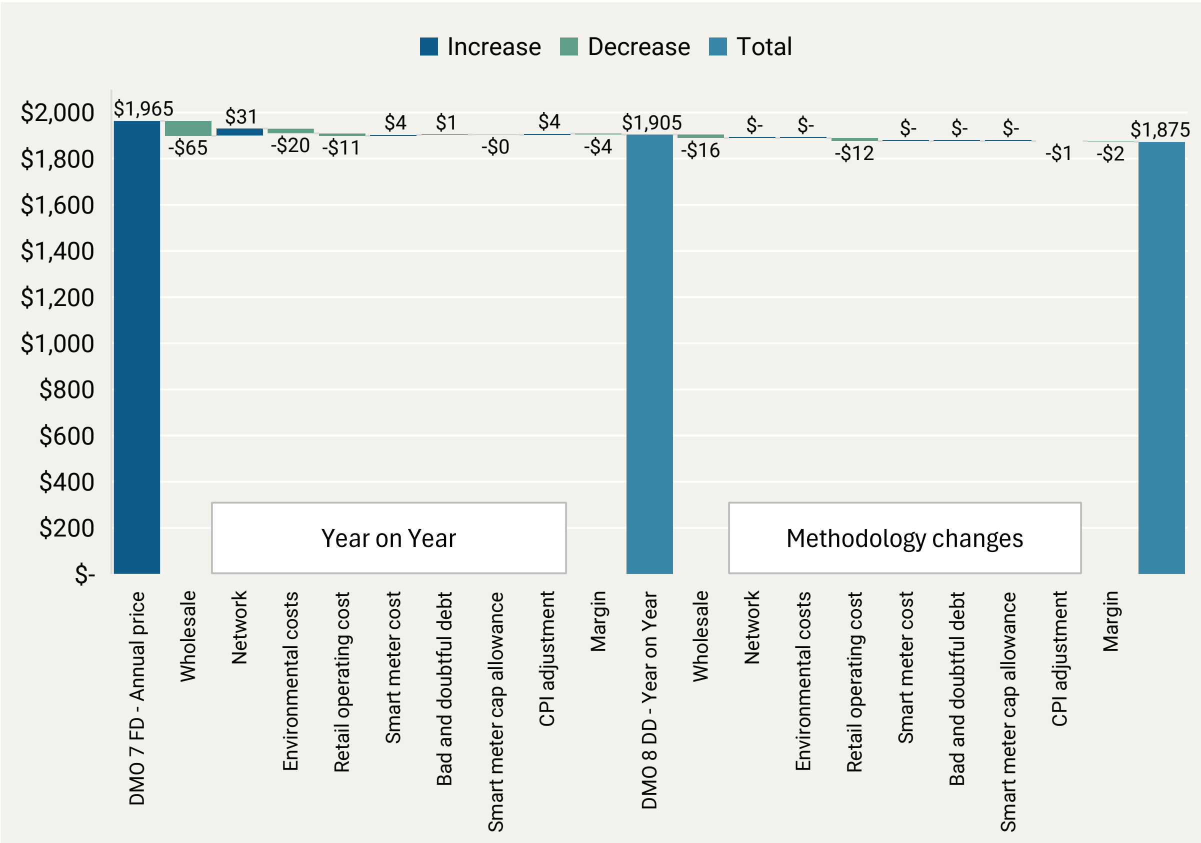


Figure F.2 Ausgrid small business flat rate

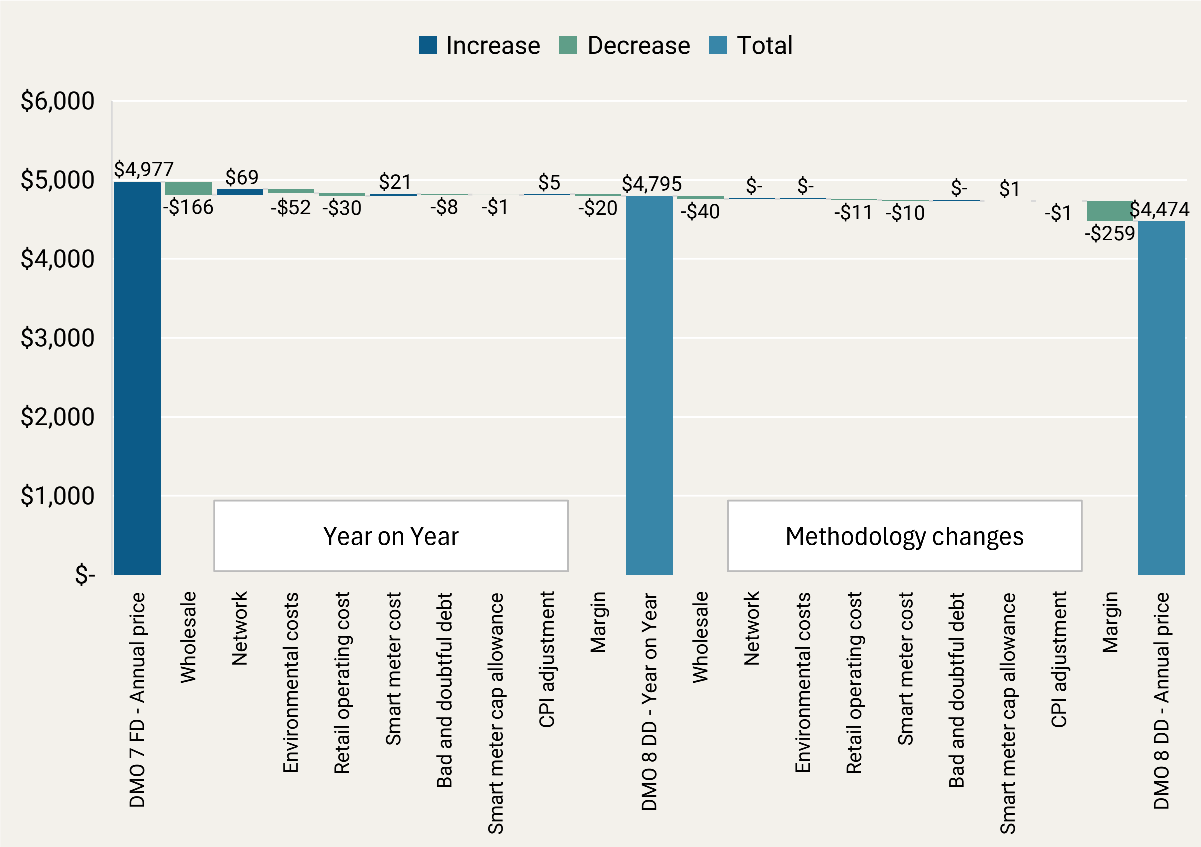


Figure F.3 Endeavour Energy residential flat rate

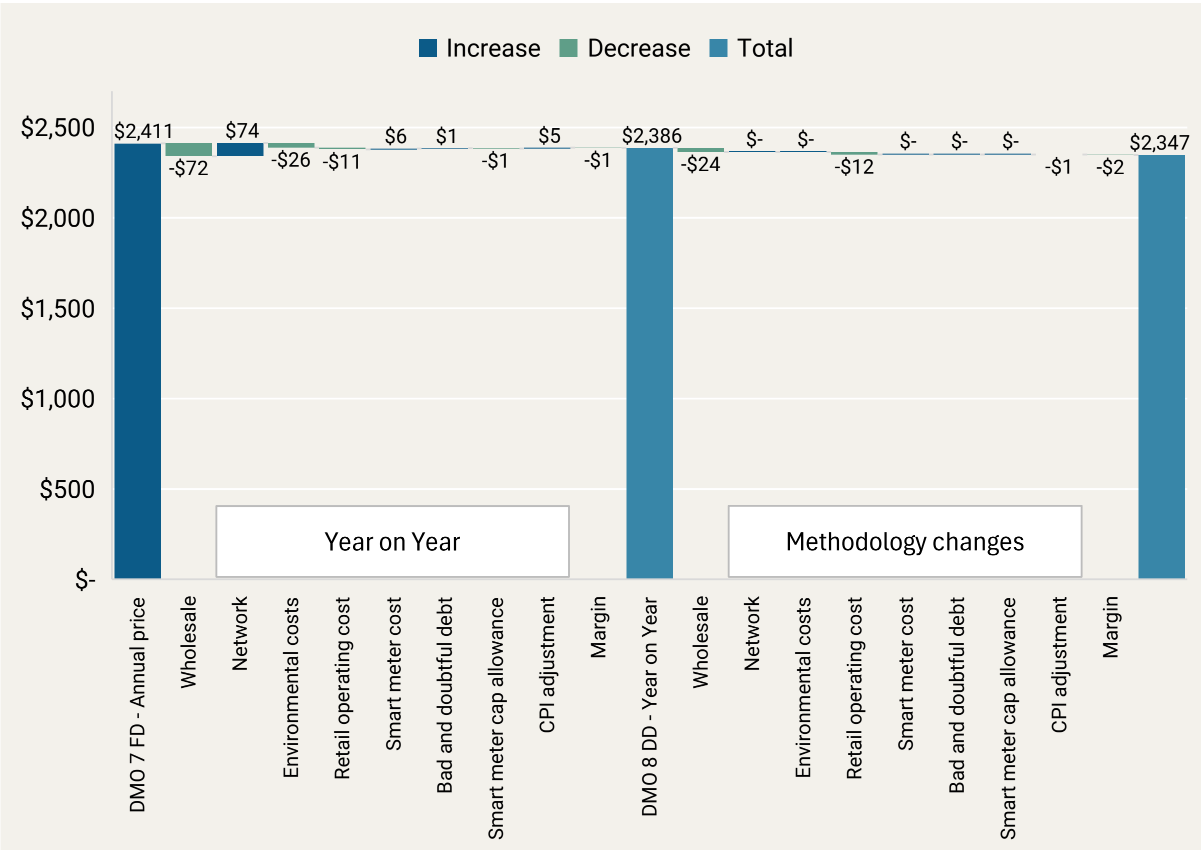


Figure F.4 Endeavour Energy small business flat rate

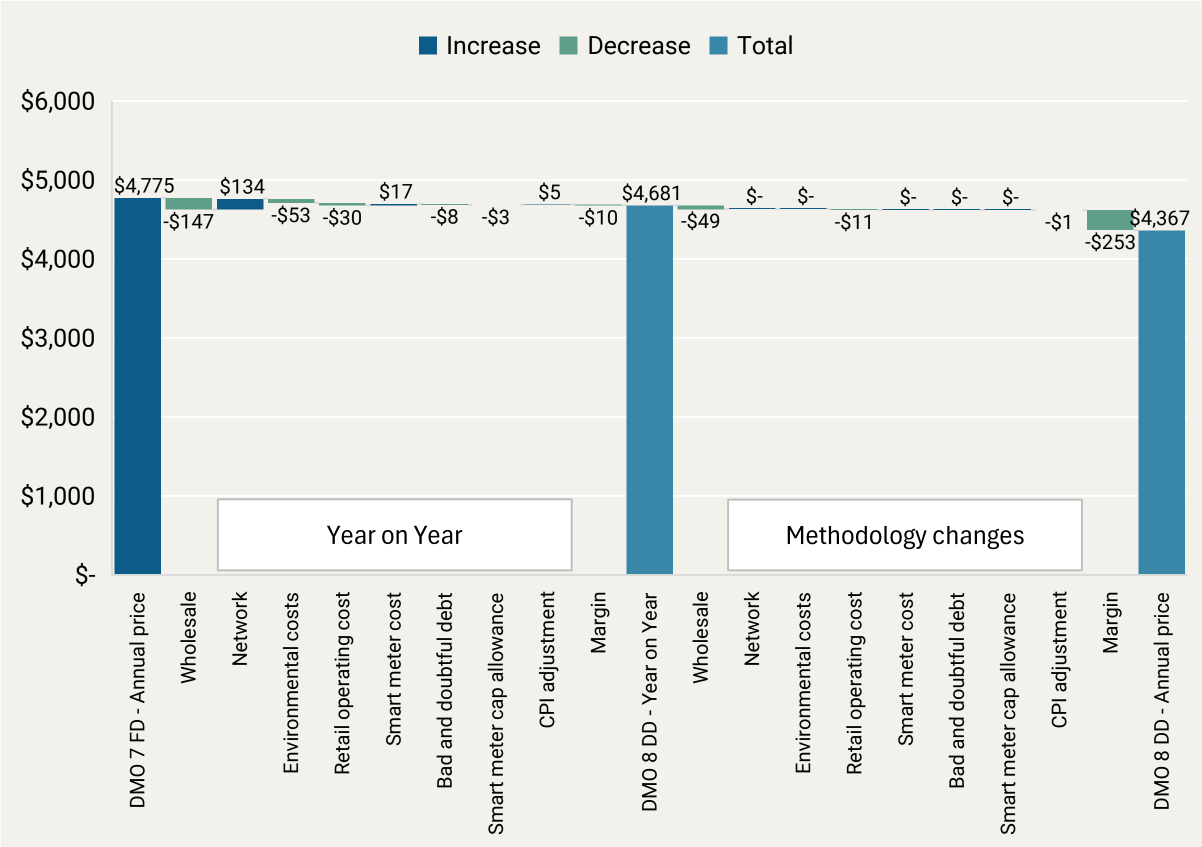


Figure F.5 Essential Energy residential flat rate

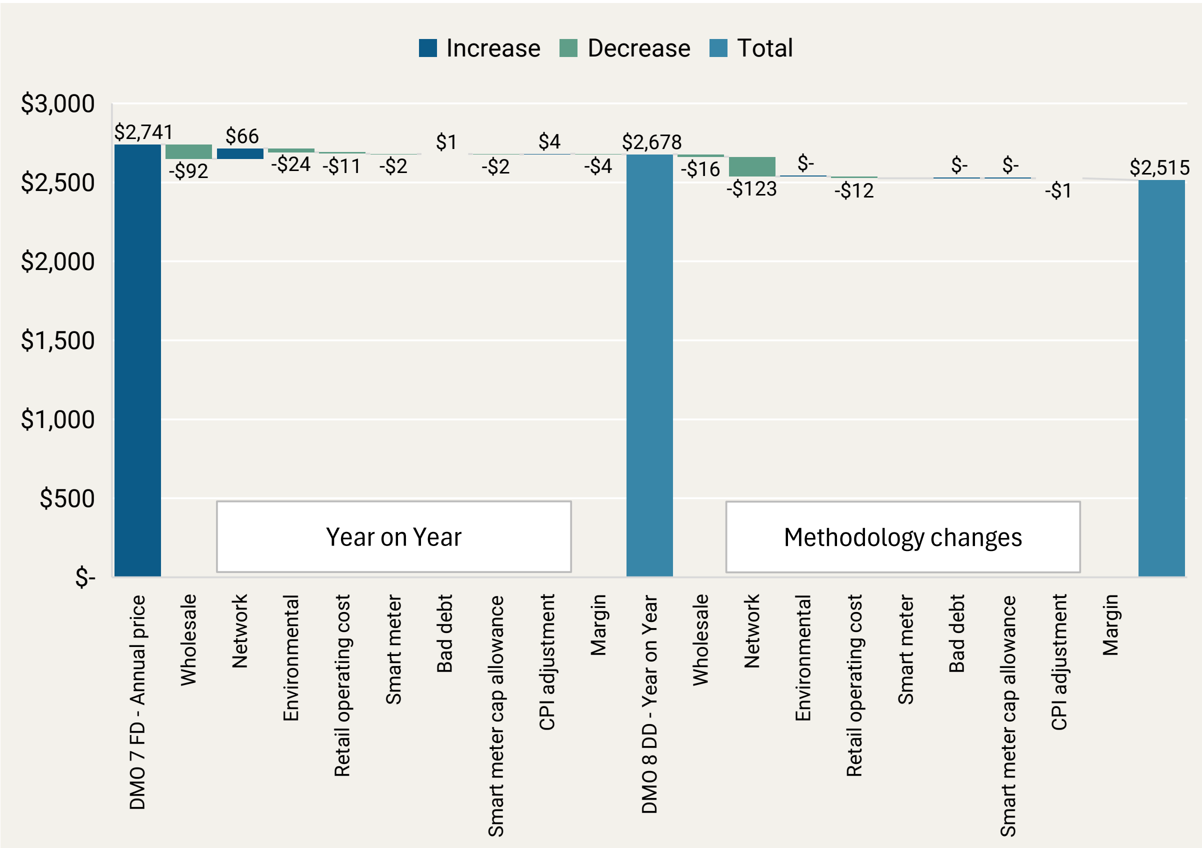


Figure F.6 Essential Energy small business flat rate

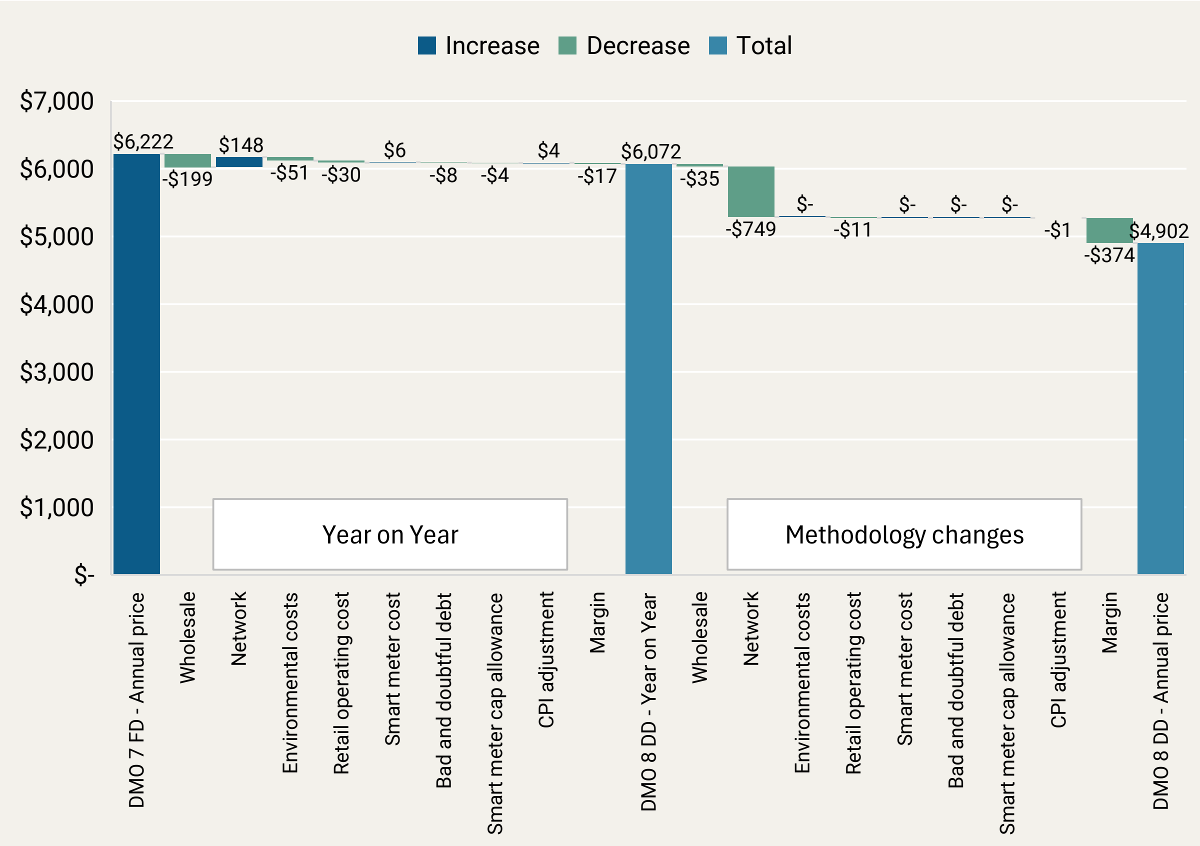


Figure F.7 Energex residential flat rate

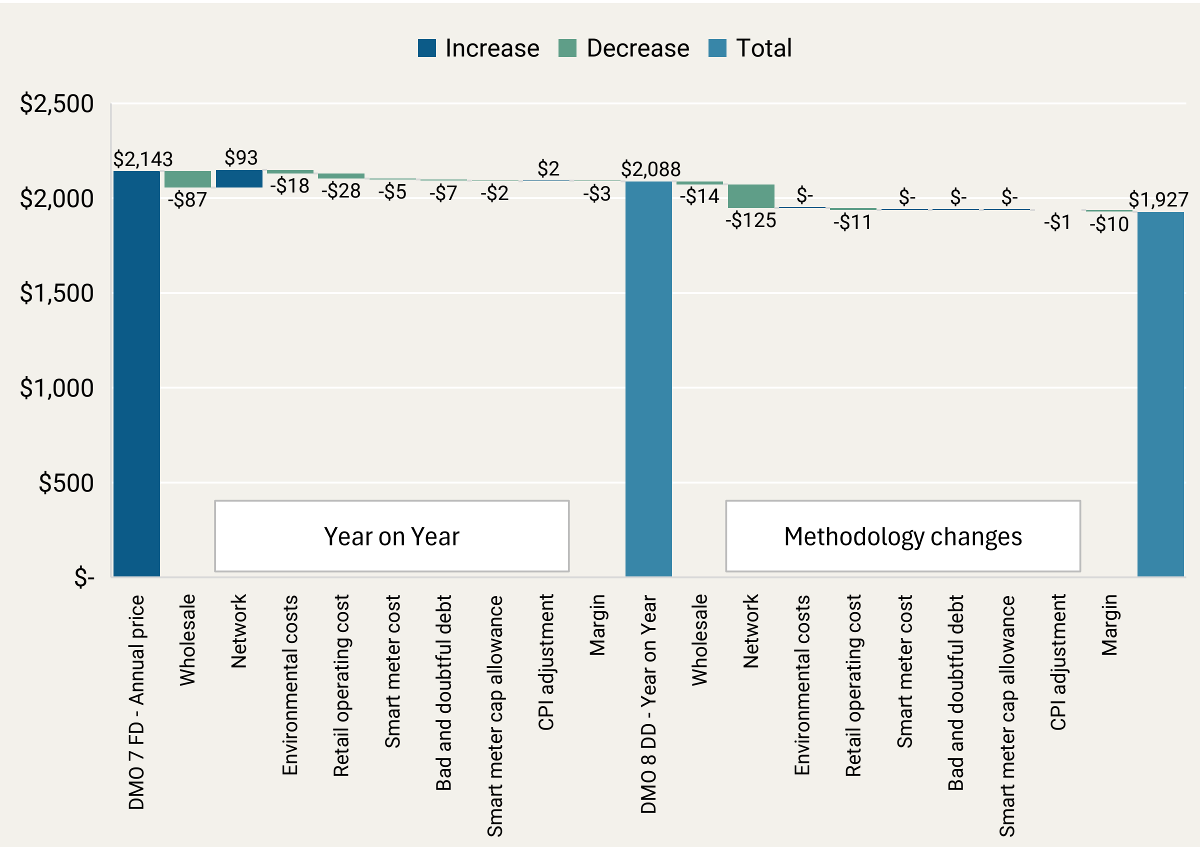


Figure F.8 Energex small business flat rate

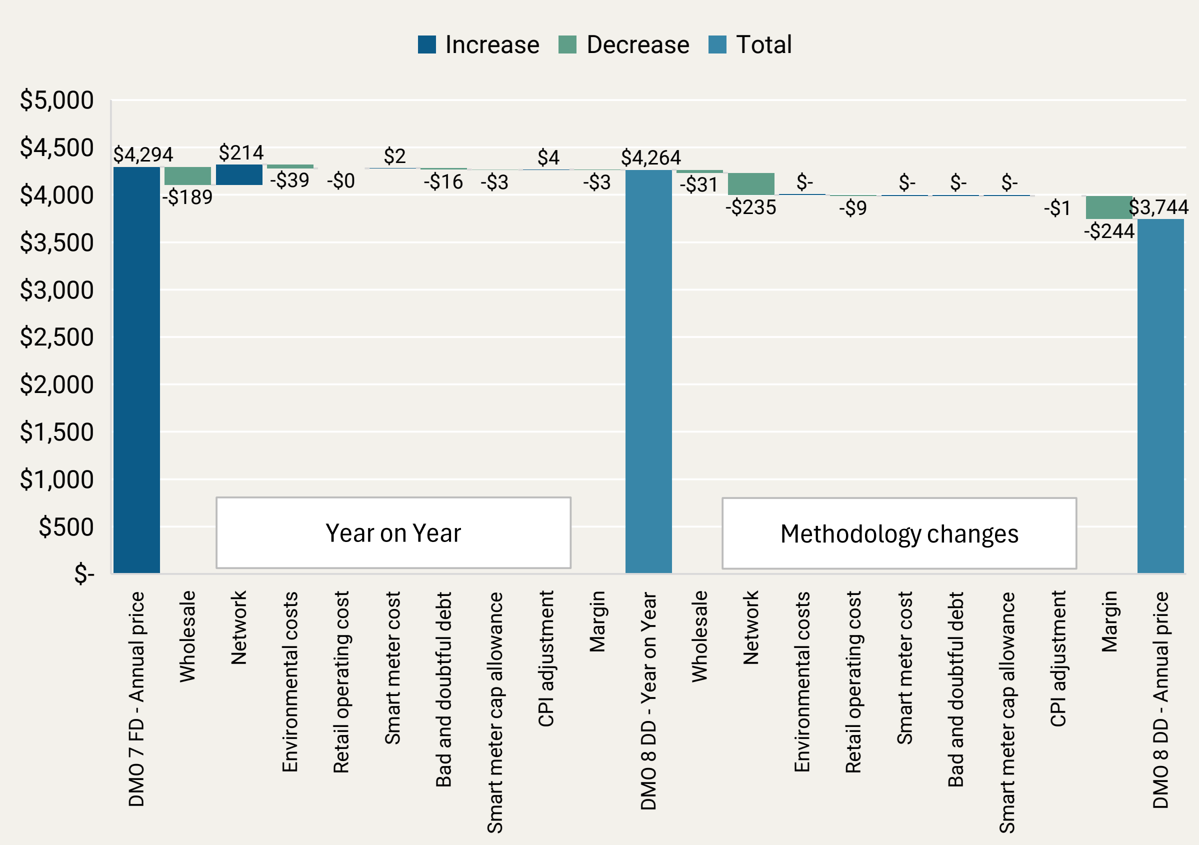


Figure F.9 SA Power Networks residential flat rate

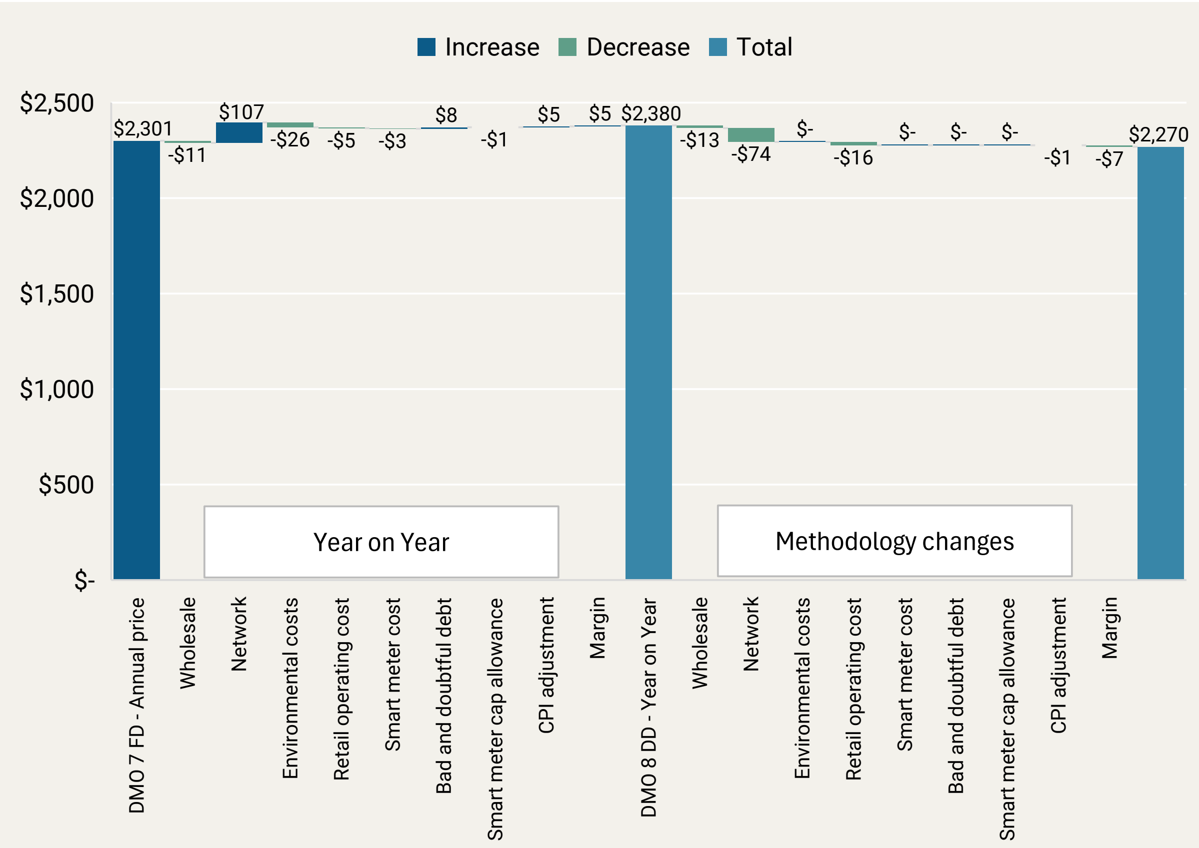
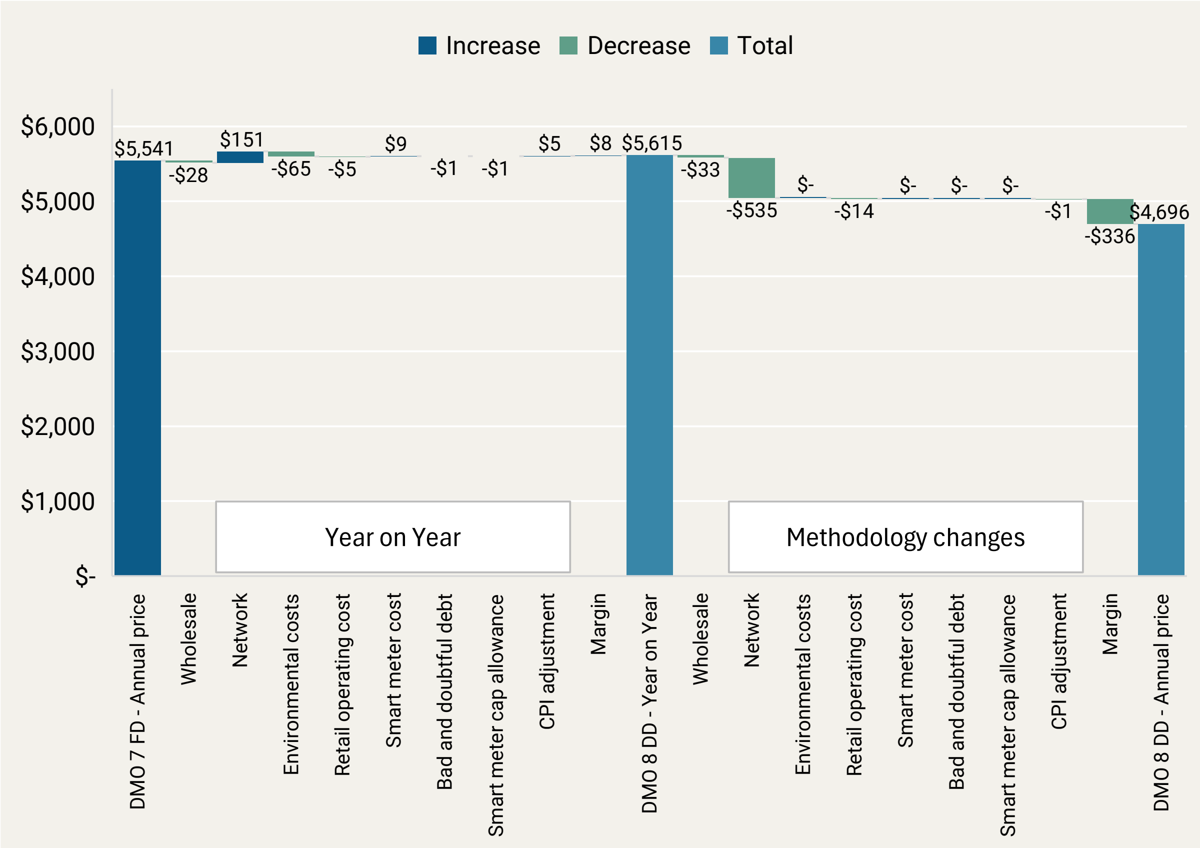


Figure F.10 SA Power Networks small business flat rate



G State-based summaries

This appendix includes detail on the DMO cost stack changes from the DMO 7 final determination to the DMO 8 draft determinations for each state.

New South Wales

Table G.1 Residential flat rate, change from final determination DMO 7 to draft determination DMO 8, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Ausgrid	Network cost	711.92		743.09		31.17	4.4%
	Wholesale cost	753.97		673.48		-80.49	-10.7%
	Environmental cost	68.33		48.17		-20.16	-29.5%
	Retail cost	312.51		297.31		-15.21	-4.9%
	Retail margin	117.88	*6.0%*	112.47	*6.0%*	-5.41	-4.6%
	Total	**1,965**		**1,875**		**-90**	**-4.6%**
Endeavour	Network cost	836.51		910.76		74.26	8.9%
	Wholesale cost	998.46		902.76		-95.70	-9.6%
	Environmental cost	87.41		61.62		-25.79	-29.5%
	Retail cost	344.31		331.36		-12.94	-3.8%
	Retail margin	144.68	*6.0%*	140.84	*6.0%*	-3.84	-2.7%
	Total	**2,411**		**2,347**		**-64**	**-2.7%**
Essential	Network cost	1,248.98		1,191.33		-57.65	-4.6%
	Wholesale cost	903.45		795.52		-107.94	-11.9%
	Environmental cost	80.17		56.52		-23.65	-29.5%
	Retail cost	343.76		321.19		-22.58	-6.6%
	Retail margin	164.45	*6.0%*	150.93	*6.0%*	-13.52	-8.2%
	Total	**2,741**		**2,515**		**-226**	**-8.2%**

Table G.2 Residential time of use, change from final determination DMO 7 to draft determination DMO 8, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Ausgrid	Network cost	711.92		754.24		42.32	5.9%
	Wholesale cost	753.97		673.48		-80.49	-10.7%
	Environmental cost	68.33		48.17		-20.16	-29.5%
	Retail cost	312.51		297.31		-15.21	-4.9%
	Retail margin	117.88	*6.0%*	113.18	*6.0%*	-4.69	-4.0%
	Total	**1,965**		**1,886**		**-79**	**-4.0%**

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Endeavour	Network cost	836.51		916.11		79.61	9.5%
	Wholesale cost	998.46		902.76		-95.70	-9.6%
	Environmental cost	87.41		61.62		-25.79	-29.5%
	Retail cost	344.31		331.36		-12.94	-3.8%
	Retail margin	144.68	*6.0%*	141.18	*6.0%*	-3.50	-2.4%
	Total	**2,411**		**2,353**		**-58**	**-2.4%**
Essential	Network cost	1,248.98		1,191.33		-57.65	-4.6%
	Wholesale cost	903.45		795.52		-107.94	-11.9%
	Environmental cost	80.17		56.52		-23.65	-29.5%
	Retail cost	343.76		321.19		-22.58	-6.6%
	Retail margin	164.45	*6.0%*	150.93	*6.0%*	-13.52	-8.2%
	Total	**2,741**		**2,515**		**-226**	**-8.2%**

Table G.3 Small business flat rate, change from final determination DMO 7 to draft determination DMO 8, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Ausgrid	Network cost	1,923.34		1,992.84		69.50	3.6%
	Wholesale cost	1,909.46		1,703.07		-206.38	-10.8%
	Environmental cost	175.21		123.52		-51.69	-29.5%
	Retail cost	421.95		386.50		-35.45	-8.4%
	Retail margin	547.52	*11.0%*	268.46	*6.0%*	-279.06	-51.0%
	Total	**4,977**		**4,474**		**-503**	**-10.1%**
Endeavour	Network cost	1,597.55		1,731.92		134.37	8.4%
	Wholesale cost	2,021.84		1,826.53		-195.31	-9.7%
	Environmental cost	178.38		125.75		-52.63	-29.5%
	Retail cost	452.19		420.72		-31.47	-7.0%
	Retail margin	525.28	*11.0%*	262.02	*6.0%*	-263.26	-50.1%
	Total	**4,775**		**4,367**		**-408**	**-8.5%**
Essential	Network cost	2,959.14		2,358.68		-600.47	-20.3%
	Wholesale cost	1,946.16		1,711.52		-234.64	-12.1%
	Environmental cost	174.28		122.86		-51.42	-29.5%
	Retail cost	458.05		414.62		-43.43	-9.5%
	Retail margin	684.43	*11.0%*	294.11	*6.0%*	-390.32	-57.0%
	Total	**6,222**		**4,902**		**-1,320**	**-21.2%**

Table G.4 Small business time of use, change from final determination DMO 7 to draft determination DMO 8, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Ausgrid	Network cost	1,923.34		2,109.22		185.88	9.7%
	Wholesale cost	1,909.46		1,703.07		-206.38	-10.8%
	Environmental cost	175.21		123.52		-51.69	-29.5%
	Retail cost	421.95		386.50		-35.45	-8.4%
	Retail margin	547.52	*11.0%*	275.89	*6.0%*	-271.63	-49.6%
	Total	**4,977**		**4,598**		**-379**	**-7.6%**
Endeavour	Network cost	1,597.55		1,759.12		161.57	10.1%
	Wholesale cost	2,021.84		1,826.53		-195.31	-9.7%
	Environmental cost	178.38		125.75		-52.63	-29.5%
	Retail cost	452.19		420.72		-31.47	-7.0%
	Retail margin	525.28	*11.0%*	263.75	*6.0%*	-261.52	-49.8%
	Total	**4,775**		**4,396**		**-379**	**-7.9%**
Essential	Network cost	2,959.14		2,358.68		-600.47	-20.3%
	Wholesale cost	1,946.16		1,711.52		-234.64	-12.1%
	Environmental cost	174.28		122.86		-51.42	-29.5%
	Retail cost	458.05		414.62		-43.43	-9.5%
	Retail margin	684.43	*11.0%*	294.11	*6.0%*	-390.32	-57.0%
	Total	**6,222**		**4,902**		**-1,320**	**-21.2%**

SE Queensland

Table G.5 Residential flat rate, change from final determination DMO 7 to draft determination DMO 8, Energex (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Energex	Network cost	778.45		746.35		-32.10	-4.1%
	Wholesale cost	847.01		745.69		-101.32	-12.0%
	Environmental cost	60.31		42.49		-17.82	-29.5%
	Retail cost	328.20		277.31		-50.90	-15.5%
	Retail margin	128.55	*6.0%*	115.65	*6.0%*	-12.90	-10.0%
	Total	**2,143**		**1,927**		**-216**	**-10.1%**

Table G.6 Residential time of use, change from final determination DMO 7 to draft determination DMO 8, Energex (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Energex	Network cost	778.45		746.35		-32.10	-4.1%
	Wholesale cost	847.01		745.69		-101.32	-12.0%
	Environmental cost	60.31		42.49		-17.82	-29.5%
	Retail cost	328.20		277.31		-50.90	-15.5%
	Retail margin	128.55	*6.0%*	115.65	*6.0%*	-12.90	-10.0%
	Total	**2,143**		**1,927**		**-216**	**-10.1%**

Table G.7 Small business flat rate, change from final determination DMO 7 to draft determination DMO 8, Energex (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Energex	Network cost	1,506.37		1,486.17		-20.21	-1.3%
	Wholesale cost	1,823.45		1,603.20		-220.25	-12.1%
	Environmental cost	131.10		92.36		-38.74	-29.5%
	Retail cost	360.66		337.91		-22.75	-6.3%
	Retail margin	472.33	*11.0%*	224.66	*6.0%*	-247.67	-52.4%
	Total	**4,294**		**3,744**		**-550**	**-12.8%**

Table G.8 Small business time of use, change from final determination DMO 7 to draft determination DMO 8, Energex (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
Energex	Network cost	1,506.37		1,486.17		-20.21	-1.3%
	Wholesale cost	1,823.45		1,603.20		-220.25	-12.1%
	Environmental cost	131.10		92.36		-38.74	-29.5%
	Retail cost	360.66		337.91		-22.75	-6.3%
	Retail margin	472.33	*11.0%*	224.66	*6.0%*	-247.67	-52.4%
	Total	**4,294**		**3,744**		**-550**	**-12.8%**

South Australia

Table G.9 Residential flat rate, change from final determination DMO 7 to draft determination DMO 8, SA Power Networks (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
SA Power Networks	Network cost	896.99		930.67		33.67	3.8%
	Wholesale cost	858.80		834.55		-24.24	-2.8%
	Environmental cost	72.25		46.34		-25.91	-35.9%
	Retail cost	334.47		321.89		-12.58	-3.8%
	Retail margin	138.03	*6.0%*	136.18	*6.0%*	-1.86	-1.3%
	Total	**2,301**		**2,270**		**-31**	**-1.3%**

Table G.10 Residential time of use, change from final determination DMO 7 to draft determination DMO 8, SA Power Networks (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
SA Power Networks	Network cost	896.99		930.67		33.67	3.8%
	Wholesale cost	858.80		834.55		-24.24	-2.8%
	Environmental cost	72.25		46.34		-25.91	-35.9%
	Retail cost	334.47		321.89		-12.58	-3.8%
	Retail margin	138.03	*6.0%*	136.18	*6.0%*	-1.86	-1.3%
	Total	**2,301**		**2,270**		**-31**	**-1.3%**

Table G.11 Small business flat rate, change from final determination DMO 7 to draft determination DMO 8, SA Power Networks (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
SA Power Networks	Network cost	2,281.98		1,897.99		-383.99	-16.8%
	Wholesale cost	2,124.17		2,063.56		-60.61	-2.9%
	Environmental cost	180.62		115.84		-64.78	-35.9%
	Retail cost	344.73		336.61		-8.12	-2.4%
	Retail margin	609.51	*11.0%*	281.74	*6.0%*	-327.77	-53.8%
	Total	**5,541**		**4,696**		**-845**	**-15.2%**

Table G.12 Small business time of use, change from final determination DMO 7 to draft determination DMO 8, SA Power Networks (nominal)

Distribution Region	Cost stack component	Final determination DMO 7 2025–26		Draft Determination DMO 8 2026–27		Difference from DMO 7 to Draft DMO 8	
		inc GST	*margin*	*inc GST*	*margin*	*$ diff*	*% diff*
SA Power Networks	Network cost	2,281.98		1,897.99		-383.99	-16.8%
	Wholesale cost	2,124.17		2,063.56		-60.61	-2.9%
	Environmental cost	180.62		115.84		-64.78	-35.9%
	Retail cost	344.73		336.61		-8.12	-2.4%
	Retail margin	609.51	*11.0%*	281.74	*6.0%*	-327.77	-53.8%
	Total	**5,541**		**4,696**		**-845**	**-15.2%**