




Australian Government



AUSTRALIAN
ENERGY
REGULATOR

2026–27 Default market offer

Final determination

A photograph of a woman with curly brown hair and a young boy in a kitchen. The woman is smiling and looking at a white meter on the wall. The boy is also smiling and looking at the meter. In the background, there is a kitchen counter with a sink, a stove, and a wooden fruit basket filled with lemons and oranges.

May 2026

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Contents

Key methodology concepts	v
Glossary	ix
1 Executive summary	1
1.1 DMO 8 prices	1
1.2 Market drivers of final DMO 8 tariffs and prices	1
1.3 Our approach to DMO 8	3
1.4 Looking ahead to DMO 9.....	6
2 Final DMO 8 prices and tariff caps	7
3 Role of the AER	14
3.1 DMO regulatory framework	14
3.2 Who the DMO protects	15
3.3 Efficient costs of supplying electricity to customers on standing offers and other mandatory considerations.....	17
3.4 New DMO guideline	18
3.5 Standing offer customers.....	18
3.6 Solar Sharer Offer	20
4 Wholesale energy costs	21
4.1 Draft determination	21
4.2 Stakeholder views	23
4.3 Final determination.....	27
5 Network costs	41
5.1 Draft determination.....	42
5.2 Stakeholder views	43
5.3 Final determination.....	46
6 Environmental costs	53
6.1 Draft determination.....	54
6.2 Stakeholder views	54
6.3 Final determination.....	54
7 Retail costs	56
7.1 Draft determination.....	57
7.2 Stakeholder views	59
7.3 Final determination.....	62
8 Retail margin	70
8.1 Draft determination.....	70
8.2 Stakeholder views	71
8.3 Final determination.....	73
9 Annual usage amounts, timing and pattern of supply, apportionment of fixed and variable costs and comparison price	77

9.1	Draft determination.....	77
9.2	Stakeholder views	79
9.3	Final determination.....	81
10	Solar Sharer Offer.....	85
10.1	Draft determination.....	87
10.2	Stakeholder views	89
10.3	Final determination.....	93
11	Appendices	101

Key methodology concepts

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

Concept	Explanation
3-hour free usage period	3 consecutive hours in the middle of each day, when electricity usage is free under the SSO.
AER information notice / request	An information notice served by the AER for information relating to section 16(4) of the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 and based on a reason to believe formed by the AER under section 44AAFA(1) of the <i>Competition and Consumer Act 2010</i> .
Annual price	For DMO 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. For DMO 8, the AER is required to calculate annual prices, as well as flat rate and time of use tariffs.
Annual usage	The per-customer amount of electricity supplied in specified distribution regions to small customers determined 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	Based on the pattern of supply, with the option to modify based on assumptions about consumer behaviour on the 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: <ul style="list-style-type: none"> • 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.
Blending	The flat rate DMO tariff allows recovery of a blend of time of use and flat rate network costs. This blend is a customer-weighted average approach, with weightings assigned to the annual cost of the flat rate network tariff and the annual cost of the time of use network tariff (based on the annual usage and pattern of supply). The flat rate network tariff weighting is the proportion of flat rate retail customers with a legacy meter, and the time of use network tariff weighting is the proportion of flat rate retail customers with a smart meter.

Concept	Explanation
Comparison price	<p>A per-customer annual amount determined by the AER for electricity supplied as a non-regulated tariff and for the regulated tariffs for small customers, derived by applying the annual usage and pattern of supply to the tariff cap. It is calculated to be a comparison point for competitive market offers and provide price protection for electricity supplied to standing offer customers for which there is no corresponding DMO regulated tariff.</p> <p>The calculation of a comparison price for non-regulated tariffs is a new requirement in the Regulations.</p>
Competition allowance	<p>Previous DMOs have either explicitly or implicitly included allowances to incentivise competition through varying approaches across DMOs.</p>
Costs to acquire and retain	<p>Costs relating to competition in the electricity market. The group of costs electricity retailers incur to acquire new customers and retain current customers, including advertising, marketing, etc.</p> <p>The Regulations require the AER to have regard to, if relevant to the region, the modest cost of acquiring and retaining small customers.</p>
Costs to serve	<p>The group of costs electricity retailers incur as part of serving their customers, such as billing and call centres.</p>
Distribution network service provider	<p>An entity that owns, operates or controls a distribution network's physical infrastructure, including the poles, cables, substations, transformers and safety equipment.</p>
DMO objective	<p>Section 9A of the Regulations provides that the objective of the industry code is to provide small customers that are supplied with electricity at standing offer prices with a fair, trusted and reasonably priced electricity option that reflects the costs of supplying small customers with an essential service.</p>
Draft determination	<p>The paper published by the AER on 19 March 2026 seeking input from stakeholders on the AER's draft determination for DMO 8.</p>
Issues paper	<p>The paper published by the AER on 5 November 2025 seeking input from stakeholders on the AER's approach to DMO 8.</p>
Large-scale Renewable Energy Target	<p>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.</p>
Load profile	<p>The aggregate customer demand profile for residential and small business customers, which is a key input into forecasting wholesale energy costs for the DMO.</p>
Load shift	<p>Households using electricity during the 3-hour free usage period instead of when they would normally use it – for example, running a washing machine or dryer in the middle of the day instead of in the evening.</p>

Concept	Explanation
Market offer	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 the contracts. As such, market offer contracts may be different to standard retail contracts.
Net System Load Profile	Data that contains aggregated electricity demand of small customers with accumulation meters (or legacy meters) only.
Outcomes paper	The paper published by the Australian Government on 4 November 2025 summarising outcomes and recommended reforms of the 2025 review of the DMO.
Pattern of supply	Representative levels of electricity consumption for each distribution region of small customers at different times throughout the day, as determined by the AER for each distribution region for both non-regulated and regulated tariffs.
Percentile estimate	The selected modelled wholesale energy 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 usage up to the reasonable use cap will be free and any usage above the cap will be charged at the reasonable use tariff cap. The Australian Government has set the cap at 24 kilowatt hours.
Reasonable use tariff cap	For an SSO tariff, the usage charge determined by the AER that applies to any electricity usage in excess of the reasonable use cap in the 3-hour free usage period.
Regulated tariff	Any of the types of tariffs for which the AER determines a comparison price and tariff cap as specified in the Regulations. This includes flat rate and time of use tariffs for residential and small business customers, as well as the SSO.
Regulations	Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 (Cth) as amended on 1 July 2026 by the Competition and Consumer (Industry Code—Electricity Retail) Amendment Regulations 2026.
Retail cost data	The data received from the AER information notice / request.
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 provides incentives 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.

Concept	Explanation
Solar Sharer Offer (SSO) outcomes paper	The paper published by the Australian Government on 23 January 2026 summarising feedback received from their consultation on the SSO in November 2025 and the proposed approach to the design and implementation of the SSO.
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.
Standing offer	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 have defaulted to a standing offer at the end of their market offer benefit period.
Tariff	Under the Regulations, 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 maximum amount of fixed charge and/or variable charges that an electricity retailer may charge small customers of that type in a distribution region for supplying electricity under a regulated tariff of that type determined by the AER.

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
GST	Goods and services tax
NEM	National Electricity Market
NSW	New South Wales
SA	South Australia
SSO	Solar Sharer Offer
TOU	Time of use
VDO	Victorian Default Offer
WEC	Wholesale energy cost

1 Executive summary

This is our final determination for retail electricity default market offer (DMO) prices and tariffs to apply from 1 July 2026 to 30 June 2027 (known as DMO 8).

The DMO is an annual electricity price cap for standing offers in New South Wales (NSW), South East Queensland (SE Queensland) and South Australia. Standing offers are default electricity plans that protect customers who do not switch to a more competitive plan. The DMO is also the comparison price for competitive market offers.

In March 2026 the Australian Government implemented reforms to the DMO framework through the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 (the Regulations).

These reforms established an 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 introduces new mandatory considerations for the Australian Energy Regulator (AER) when determining DMO prices. It also requires the AER to determine DMO tariffs (flat rate and time of use), Solar Sharer Offer (SSO) tariffs and annualised comparison prices for residential and small business consumers.

On 19 March 2026 we published the DMO 8 draft determination, outlining our proposed approach, draft prices, tariffs and assumed patterns of supply. The draft determination was subject to public consultation. As with previous determinations, we considered all feedback, observed price movements and analysed changes in market drivers occurring since the draft determination, including the onset of the conflict in the Middle East. These considerations are reflected in this final determination.

1.1 DMO 8 prices

Final DMO 8 prices and tariffs are presented in Appendix C. Chapter 2 (Table 2.1) outlines the 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 and small business customers, except for residential customers in South Australia, for which there has been an increase of 1.4%.

In NSW, compared with DMO 7, final determination prices are between 3.4% and 5.0% lower for residential customers and between 9.0% and 11.3% lower for small business customers.

In SE Queensland, compared with DMO 7, final determination prices are 7.2% lower for residential customers and 10.4% lower for small business customers.

In South Australia, compared with DMO 7, final determination prices are 1.4% higher for residential customers and 6.8% lower for small business customers.

1.2 Market drivers of final DMO 8 tariffs and prices

In calculating the DMO, we consider wholesale, network, environmental and retail costs, along with a retail margin.

DMO 8 tariffs and prices are impacted by both methodology changes and underlying market conditions. Appendix E 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 (network 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, there have been decreases in wholesale, environmental and retail costs across all regions since DMO 7.

Wholesale costs make up around 30% to 41% of the DMO prices and decreased by 2% to 14% from DMO 7 to DMO 8, depending on region. Lower wholesale costs result from decreasing contract prices for 2026–27, reflecting low spot price volatility. This is driven partly by increased output from wind and battery generators and less dependence on gas and hydro generation during evening demand peaks. South Australian wholesale costs fell less than other regions. This is due to a significant increase in ancillary service costs resulting from high-priced events for Frequency Control Ancillary Services (FCAS) that occurred in July and August 2025.

We have monitored the impact of the Middle East conflict on market conditions. Available wholesale data indicates that the conflict has not resulted in increases in wholesale energy costs (WECs). While relevant Australian Securities Exchange (ASX) contract prices increased at the onset of the conflict, they have since decreased to pre-conflict levels. Spot market conditions similarly show no observable impact from the conflict, with the National Electricity Market's (NEM) spot market volatility level the lowest observed in several years. Our final determination is based on the most recently available futures data, which we considered to be the most appropriate indicator for what may occur over 2026–27 in the wholesale market.

Network costs are a large component of DMO prices, comprising around 39% to 54% of DMO prices. In April 2026, the AER approved network tariff prices from each distribution network service provider (DNSP) for 2026–27. Compared with 2025–26, network charges have mostly increased due to the revenue paths, increasing transmission costs, inflation and the recovery of previously under-recovered revenue, as well as some state-specific drivers.

Environmental costs are a small component of the DMO, representing between 2% and 3% of the DMO 8 prices. These costs have decreased substantially since DMO 7 across all distribution regions and customer types by between 30% and 35% due to lower Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) costs.

Retail costs make up around 7% to 16% of the DMO for flat rate residential and small business customers. Retailers have reported lower costs this year, except for those relating to small business customers in South Australia, for whom costs remain stable from DMO 7. The reported decreases include reductions in costs incurred to serve customers, the costs to acquire and retain customers, and other shared costs attributable to the electricity retailing division. However, these decreases are slightly offset by the increased uptake of smart meters since DMO 7.

1.3 Our approach to DMO 8

In DMO 8 we have adjusted some aspects of the methodology to reflect the new DMO objective and mandatory considerations in the Regulations. These methodological changes have impacted the DMO 8 tariffs and prices, which are set out in Appendix E for each jurisdiction.

The changes have occurred in some components of the DMO cost stack: wholesale (percentile estimate), networks (blending network tariffs for the flat rate DMO and passing through time of use network tariffs for the time of use DMO), retail (changes for modest customer acquisition and retention costs) and margin (alignment of small business with residential).

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

1.3.1 Wholesale energy costs

Our methodology has evolved to accommodate the mandatory considerations in the Regulations when establishing an efficient forecast of wholesale costs for the DMO. The largest component of our wholesale cost forecast is the wholesale energy cost (WEC). Our final determination uses the 50th percentile of modelled wholesale cost outcomes and includes a volatility allowance for residential and small business customers. 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 decision is based on our examination of past wholesale modelling outcomes relative to market performance and on the reforms to the DMO framework.

We maintain our draft determination approach to use only interval meter data as our basis for forecasting controlled load demand, in all regions. This reflects the improved accuracy of this dataset and ensures future amendments to the methodology will not be required as the transition to smart meters for all customers across the NEM continues. We have also removed the interval meter controlled load data from the general energy consumption load profiles.

1.3.2 Network costs

For flat rate tariff caps and comparison prices, we have changed the approach from that proposed in our draft determination based on feedback and considerations raised by stakeholders in submissions to the draft determination. Our final determination applies a blending approach as we consider neither the flat rate nor time of use network tariff alone accurately reflects efficient costs. This is because there is a mix of these 2 network tariffs among flat rate retail customers with legacy meters and smart meters. The blended approach will capture the increasing use of smart meters, and time of use network tariffs, as Legacy Meter Replacement Plans (LMRPs) increasingly see smart meters replacing older-style meters by 2030.

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 network tariff is a demand tariff. However, under the Regulations, a time of use DMO flexible tariff cannot include demand charges.

1.3.3 Environmental costs

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

1.3.4 Retail costs

We maintain our customer-weighted average approach for retail costs to serve and other costs because it provides an efficient benchmark. It also aligns with the Essential Services Commission of Victoria's (ESC) approach in setting efficient retailer costs.

We maintain our existing customer-weighted average approach to quantifying smart meter cost allowances and the cost of capital allowance.

We apply the standing offer customer-weighted average approach to costs to acquire and retain small customers. We consider this best achieves the requirement under the Regulations to allow a modest amount for these costs.

We apply a customer-weighted average of actual written-off bad debt expenses reported by retailers. This is a change from previous determinations, which were based on costs related to provisioning for bad and doubtful debt. We consider this approach more accurately reflects these costs to retailers. It also better reflects efficient retailer costs under the new regulatory framework and aligns with the ESC approach.

We maintain our draft determination approach to allocate bad debt as a fixed cost component of the DMO, rather than a variable component that scales with consumption.

1.3.5 Retail margins

We maintain our draft determination approach to apply the retail margin as a percentage of total DMO costs and apply uniform retail margins of 6% across both residential and small business customers.

Although the Regulations no longer include reference to retailers making a reasonable profit, the AER is directed to consider the efficient costs to supply electricity to small customers on standing offers, which we consider to be inclusive of retail margins. We are also directed to consider the long-term interest of consumers and the objective of the Regulations. Our final determination reflects the relevant retailer risks being accounted for in other DMO 8 cost components to ensure the costs are not double counted. We have also benchmarked our decision against the retail margin determinations from other regulators.

1.3.6 Overall changes to the DMO

The Regulations require us to develop DMO tariff caps that determine the maximum amount of any fixed charge or variable charge or charges. To determine tariff caps, we allocate all costs to the daily supply charge, usage charge or a mix of both. We maintain the draft determination approach to allocate fixed costs to the daily supply charge and variable costs to the usage charge(s). We consider this approach is cost reflective and transparent. Stakeholders were supportive of a consistent and transparent approach over manual adjustments to address potentially higher daily supply charges because of this decision.

We use the time of use tariff to determine the comparison price for non-regulated tariffs for residential and small business customers.

We maintain our approach from DMO 7 regarding the annual usage benchmarks for residential and small business customers, including the controlled load amounts, and the calculation of the timing and pattern of supply, updating the usage profiles with new Australian Energy Market Operator (AEMO) interval meter data.

Appendices D, E and F show all 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.

1.3.7 Solar Sharer Offer

The SSO provides all residential customers with a smart meter the opportunity to access 3 hours of free electricity during the middle of the day. This enables households to benefit from Australia's abundant solar generation regardless of whether they have solar panels. This opt-in standing offer is best suited to customers who can shift their usage into the free usage period.

We determined the first SSO tariffs in accordance with the Regulations and were also informed by the Australian Government's SSO outcomes paper.¹ This includes prioritising practicality for the initial implementation of the SSO. We have decided to maintain our approach to:

- set the free usage periods on a fixed local time basis without variation (11 am to 2 pm in NSW and SE Queensland and 12 pm to 3 pm in South Australia)
- design the SSO tariff by overlaying free usage periods on the corresponding time of use DMO tariff
- reallocate costs incurred during the free usage period to all non-free usage periods based on the assumed volume of electricity consumed in each period
- set the reasonable use tariff cap (for any usage above 24 kilowatt hours (kWh) in the free usage period) based on the corresponding off-peak or solar soak SSO tariff rate.

This approach results in the usage charges outside the free usage period being 1 to 4 cents per kWh higher than the corresponding standard time of use DMO tariff, depending on the DMO region.

We have maintained our position from the draft determination to not assume any change in consumer behaviour when pricing the SSO tariffs. No data is currently available that enables us to properly understand what the consumer behavioural response to the SSO may be. We consider that our approach better protects customers and meets the Australian Government's design principle that customers who shift load are better off overall. In the absence of data on consumer response, we consider not assuming any change in consumer behaviour when pricing the SSO tariffs would best meet this principle. We will closely monitor customer and market responses to the SSO to better understand consumer behaviour and inform our considerations of the SSO in future DMO determinations.

¹ DCCEEW, [Solar Sharer Offer consultation outcomes paper](#), Department of Climate Change, Energy, the Environment and Water, 23 January 2026, pp. 8–9.

1.4 Looking ahead to DMO 9

Some further aspects of the Australian Government's reforms are expected 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.
- **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 Australian Government has indicated that DMO protections will be extended to small customers in embedded networks from DMO 9 onwards.

We intend to engage with stakeholders on these issues through consultation on the DMO guideline and in developing our DMO 9 determinations.

2 Final DMO 8 prices and tariff caps

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

Table 2.1 DMO 2026–27 final determination prices, residential customers, changes from DMO 7 (nominal and real terms), inc. GST

Distribution region	Description	Residential, flat rate	Residential, time of use	Solar Sharer Offer
Ausgrid	DMO price	\$1,899	\$1,893	\$1,893
	For annual usage of	3,900 kWh	3,900 kWh	3,900 kWh
	Change y-o-y	-\$66 (-3.4%)	-\$72 (-3.7%)	–
	Change y-o-y (real)	-\$160 (-8.2%)	-\$166 (-8.5%)	–
Endeavour Energy	DMO price	\$2,328	\$2,320	\$2,320
	For annual usage of	4,900 kWh	4,900 kWh	4,900 kWh
	Change y-o-y	-\$83 (-3.4%)	-\$91 (-3.8%)	–
	Change y-o-y (real)	-\$199 (-8.2%)	-\$207 (-8.6%)	–
Essential Energy	DMO price	\$2,604	\$2,530	\$2,530
	For annual usage of	4,600 kWh	4,600 kWh	4,600 kWh
	Change y-o-y	-\$137 (-5.0%)	-\$211 (-7.7%)	–
	Change y-o-y (real)	-\$269 (-9.8%)	-\$343 (-12.5%)	–
Energex	DMO price	\$1,988	\$1,914	\$1,914
	For annual usage of	4,600 kWh	4,600 kWh	4,600 kWh
	Change y-o-y	-\$155 (-7.2%)	-\$229 (-10.7%)	–
	Change y-o-y (real)	-\$258 (-12.0%)	-\$332 (-15.5%)	–
SA Power Networks	DMO price	\$2,334	\$2,276	\$2,276
	For annual usage of	4,000 kWh	4,000 kWh	4,000 kWh
	Change y-o-y	+\$33 (+1.4%)	-\$25 (-1.1%)	–
	Change y-o-y (real)	-\$77 (-3.4%)	-\$135 (-5.9%)	–

Note: Real comparisons with DMO 7 are based on the Reserve Bank of Australia's (RBA's) [2025–26 inflation forecast](#) of 4.8% in its May 2026 Statement on Monetary Policy.

Table 2.2 DMO 2026–27 final determination prices, small business customers, changes from DMO 7 (nominal and real terms), inc. GST

Distribution region	Description	Small business, flat rate		Small business, time of use	
Ausgrid	DMO price	\$4,523		\$4,450	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-\$454	(-9.1%)	-\$527	(-10.6%)
	Change y-o-y (real)	-\$693	(-13.9%)	-\$766	(-15.4%)
Endeavour Energy	DMO price	\$4,343		\$4,326	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-\$432	(-9.0%)	-\$449	(-9.4%)
	Change y-o-y (real)	-\$661	(-13.8%)	-\$678	(-14.2%)
Essential Energy	DMO price	\$5,517		\$4,919	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-\$705	(-11.3%)	-\$1,303	(-20.9%)
	Change y-o-y (real)	-\$1,004	(-16.1%)	-\$1,602	(-25.7%)
Energex	DMO price	\$3,849		\$3,693	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-\$445	(-10.4%)	-\$601	(-14.0%)
	Change y-o-y (real)	-\$651	(-15.2%)	-\$807	(-18.8%)
SA Power Networks	DMO price	\$5,162		\$4,868	
	For annual usage of	10,000 kWh		10,000 kWh	
	Change y-o-y	-\$379	(-6.8%)	-\$673	(-12.1%)
	Change y-o-y (real)	-\$645	(-11.6%)	-\$939	(-16.9%)

Note: Real comparisons with DMO 7 are based on RBA [2025–26 inflation forecast](#) of 4.8% in its May 2026 Statement on Monetary policy.

Final 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. All tariff caps include GST.

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

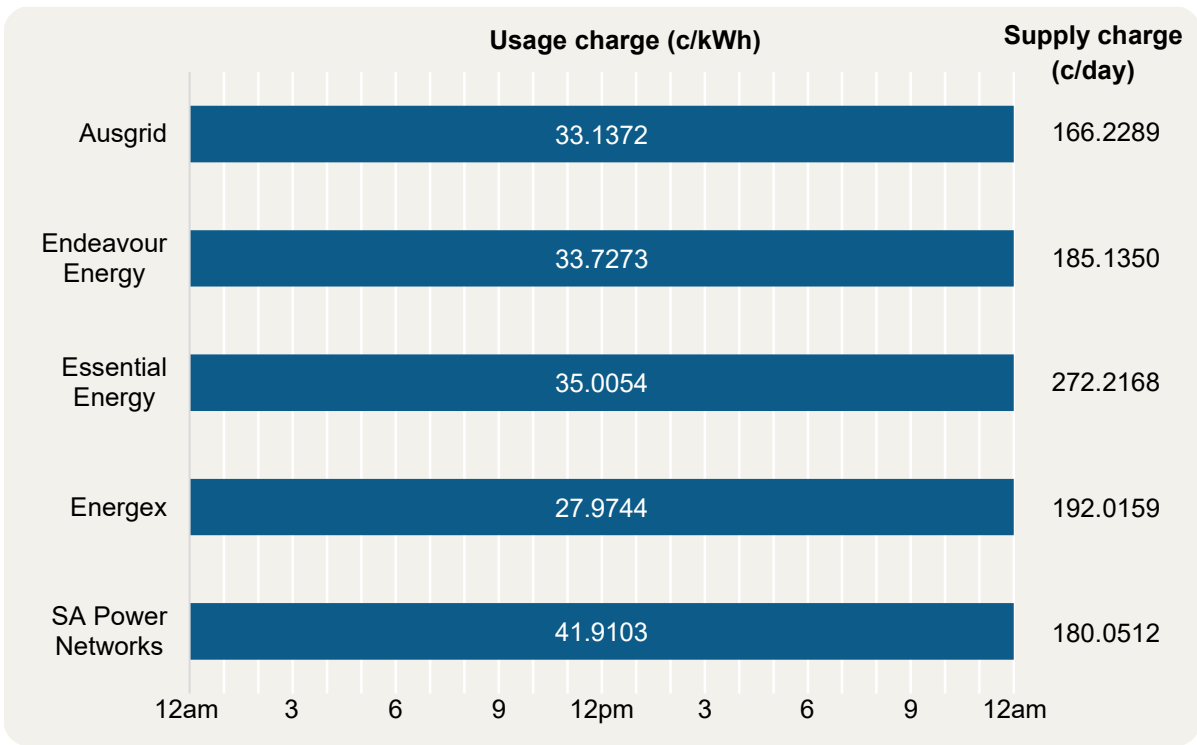
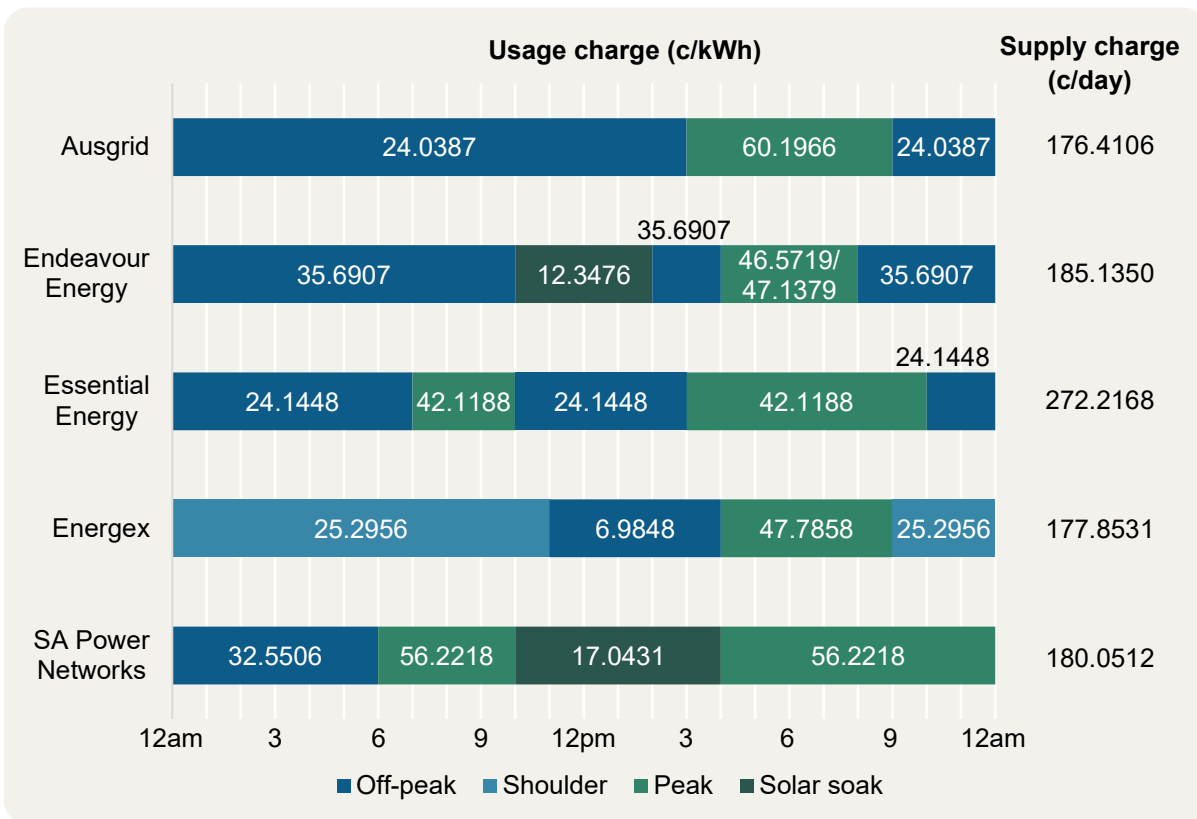
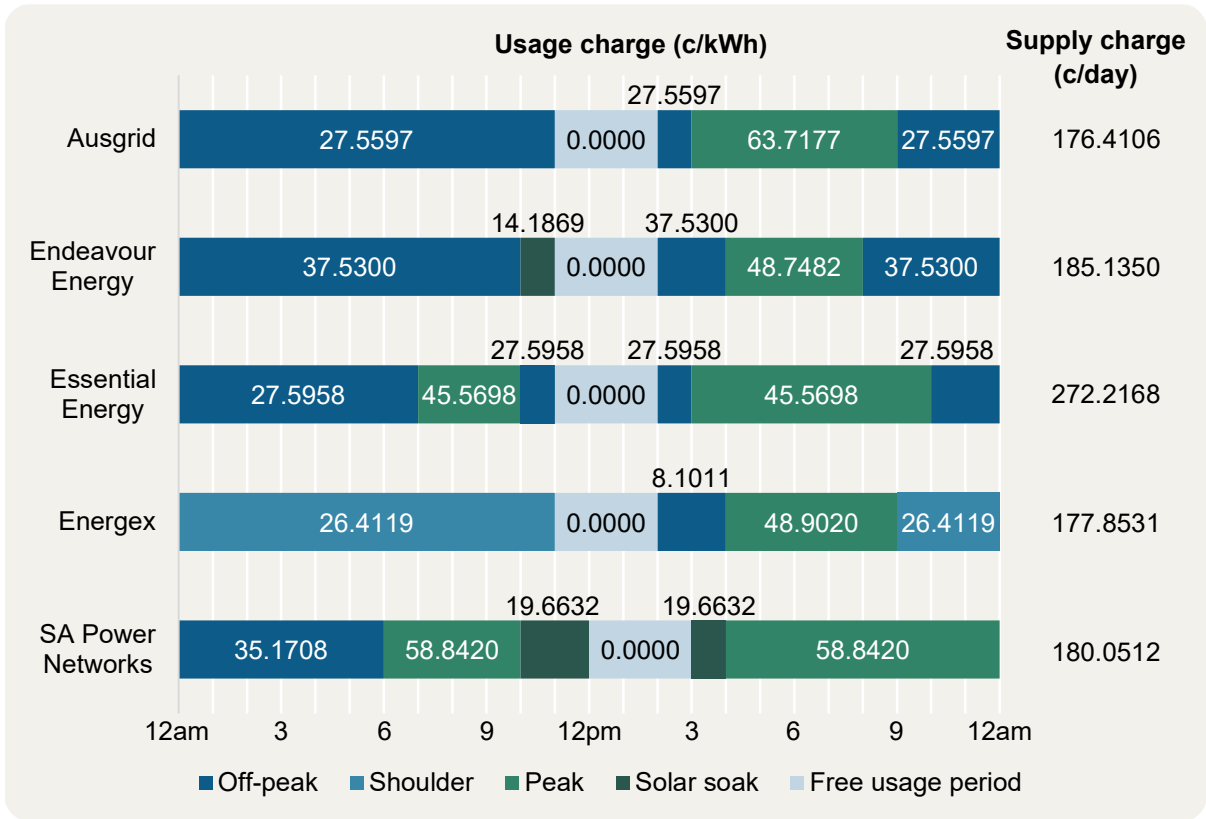


Figure 2.2 DMO 2026–27 final determination, residential, time of use DMO tariff caps



Note: Ausgrid does not have a peak period in April, May, September and October. Endeavour Energy's peak charge includes a high season charge and low season charge.

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



Note: Ausgrid does not have a peak period in April, May, September and October. Endeavour Energy has a single year-round peak charge for simplicity, instead of a high season and low season peak charge like the time of use DMO. 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 final determination, small business, flat rate DMO tariff caps

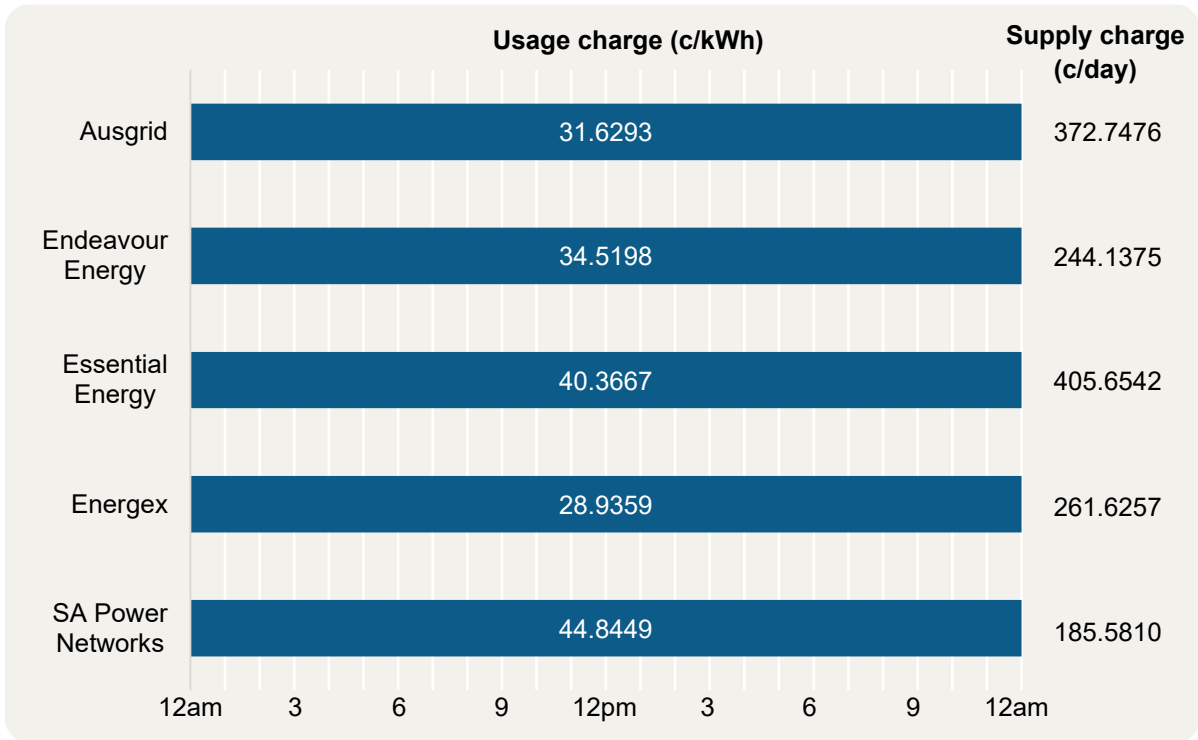
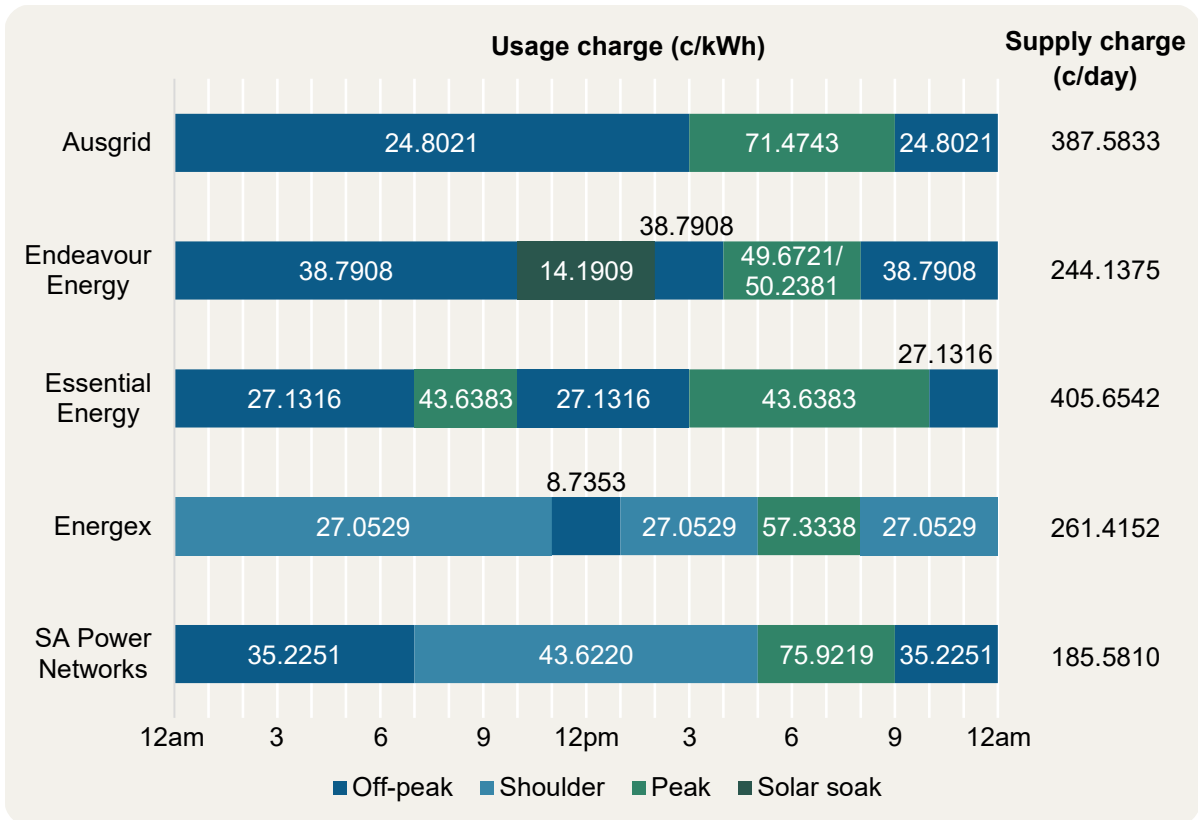


Figure 2.5 DMO 2026–27 final determination, small business, time of use DMO tariff caps



Note: Ausgrid does not have a peak period in April, May, September and October. Energex’s peak period is replaced by a shoulder period on Saturdays and Sundays. On weekdays from November to March, SA Power

Networks' periods are as shown above. On non-workdays from November to March, SA Power Networks' shoulder period is replaced by an off-peak period. From April to October, on workdays, SA Power Networks' peak period is replaced by a shoulder period, and on non-workdays, the whole day is an off-peak period. Endeavour Energy's peak charge includes a high season charge and low season charge.

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 Offer).

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

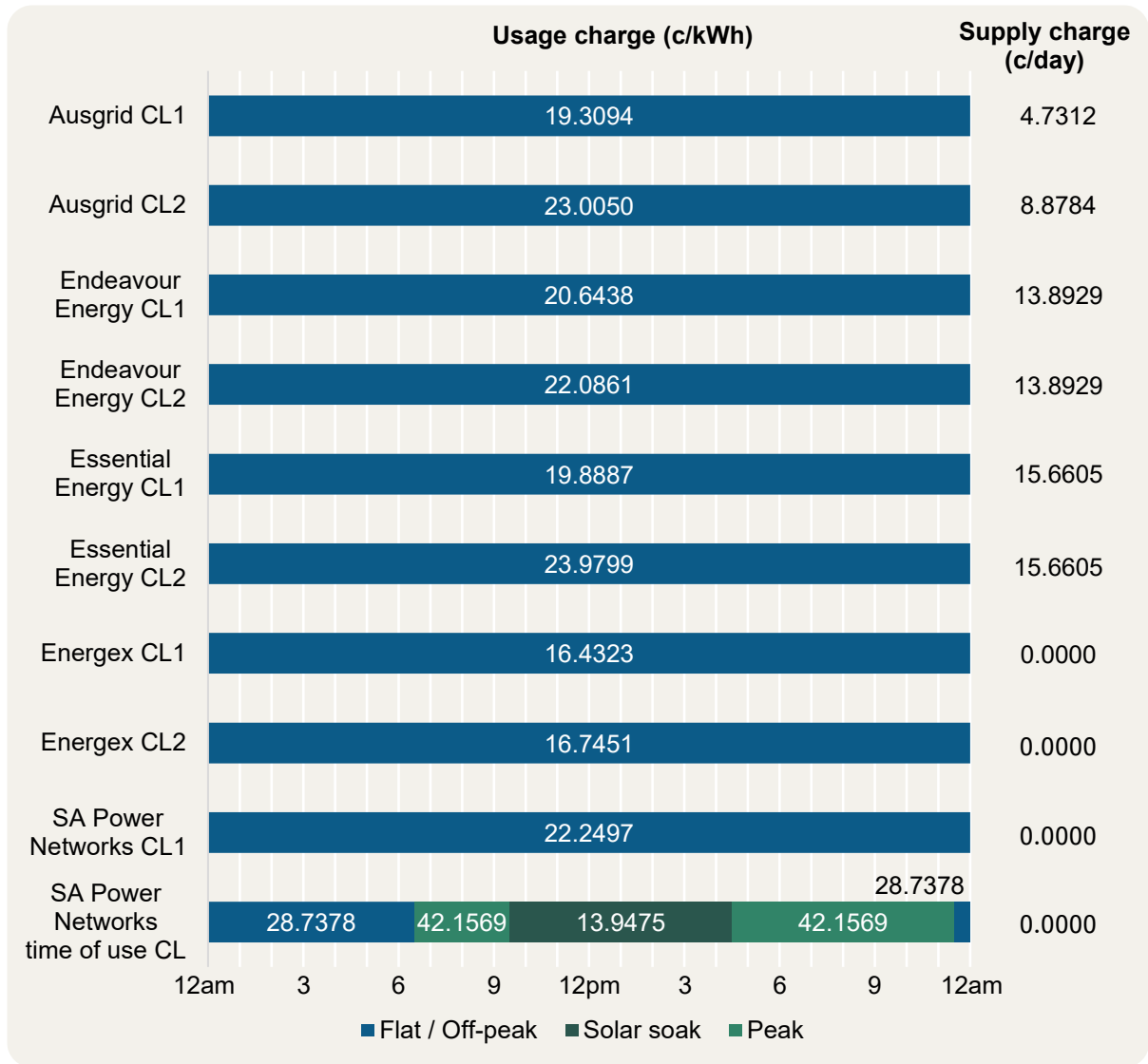
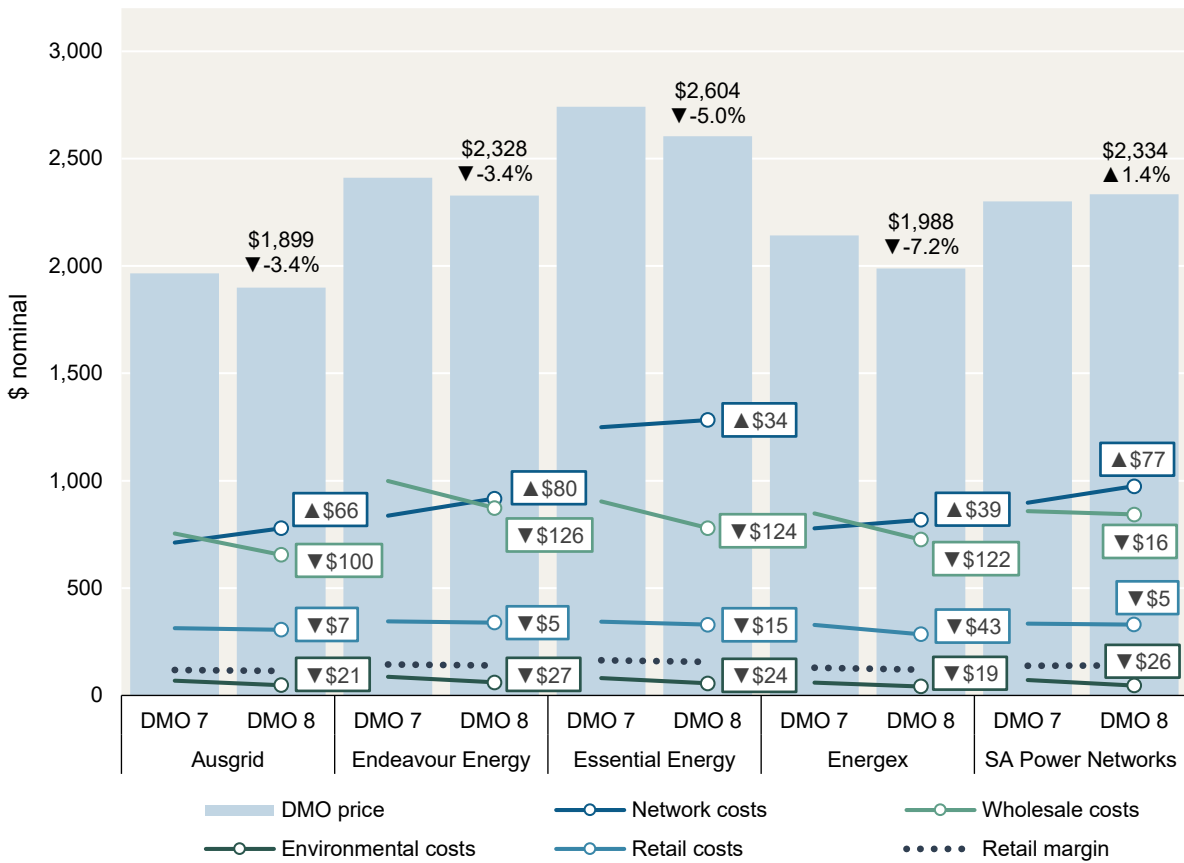


Figure 2.7 shows the movement in the key cost components since DMO 7. It illustrates that all key cost components, except for network costs, have decreased since DMO 7.

Figure 2.7 Composition of the DMO (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 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.²

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.³

Under the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 (Cth) (as amended on 1 July 2026)⁴ (the Regulations), our role is to set DMO prices each year for non-price regulated distribution network regions – NSW (Endeavour Energy, Essential Energy and Ausgrid), SE Queensland (Energex) and South Australia (SA Power Networks).⁵

3.1 DMO regulatory framework

The DMO framework was reviewed in 2025 by the Australian Government, resulting in amendments to the Regulations and changes to the way the AER is required to set the DMO.⁶

3.1.1 Amended DMO Regulations⁷

The amended Regulations include a new objective⁸ and mandatory considerations as set out in Figure 3.1.⁹

² 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.

³ 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.

⁴ Competition and Consumer (Industry Code—Electricity Retail) Amendment Regulations 2026. Section 4 of the *Acts Interpretation Act 1901* (as applied by s. 13 of the *Legislation Act 2003*) allows the making of instruments, including the AER determination under section 16, in anticipation of the commencement of these Amendment Regulations on 1 July 2026.

⁵ Regulations, s. 15(1).

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

⁷ Unless otherwise stated all references to ‘the Regulations’ will be to the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 as amended on 1 July.

⁸ Regulations, s. 9A(1).

⁹ Regulations, ss. 16(4).

Figure 3.1 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.¹⁰

The amendments have removed the reasonable profit principle¹¹ and any competition allowance.¹² 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.¹³ Chapter 8 covers this in detail.

3.2 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.¹⁴ The new Regulations expand the coverage of the DMO to small customers on standing offers across a range of defined tariffs and include a comparison price for non-regulated tariffs. The AER

¹⁰ Regulations, ss. 16(4).

¹¹ Regulations (prior to 1 July 2026), s. 16(4)(b).

¹² [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.

¹³ [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.

¹⁴ Regulations, s. 6. Small business customers are those that use less than 100 MWh a year.

may also decide to cover other types of tariffs in consultation with stakeholders in future DMO determinations.

The DMO outcomes paper states the intention for the DMO to be extended to small customers in embedded networks from DMO 9 onwards.¹⁵

3.2.1 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.¹⁶

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.¹⁷

The AER has discretion to set additional tariff types to receive a regulated DMO tariff cap.¹⁸ 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 regulated tariffs and non-regulated tariffs

Under the Regulations, the AER is required to set a comparison price for each regulated tariff and a comparison price for 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.

For non-regulated tariffs, the AER must determine a comparison price that applies to all market and standing offers that are not able to be compared with the regulated tariffs – for example, because they have different structures or characteristics. This comparison price is a reasonable per-customer annual price for the year in relation to supplying electricity under the non-regulated tariff. 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.

¹⁵ 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.

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

¹⁷ Regulations, s. 16(1A)(c).

¹⁸ Regulations, ss. 15A and 5 for the definition of 'regulated tariff'.

The Australian Competition and Consumer Commission (ACCC) and the AER have released a joint compliance bulletin to guide retailers in following these requirements under the changes to the Regulations, including for communication with customers.¹⁹

3.3 Efficient costs of supplying electricity to customers on standing offers and other mandatory considerations

In submissions to our draft determination, both retailers and consumer groups supported the new DMO objective as a fair, trusted and reasonably priced safety net for standing offer customers. This codification of an objective for the DMO was also seen as timely by some stakeholders due to increasing uncertainty and cost-of-living pressures.²⁰

However, several retailers expressed concerns around how the application of an efficient cost approach to each element of the cost stack potentially risks the resulting DMO price being set below an efficient price for businesses. They contended that when each element of the cost stack is assessed at an efficient level, the resulting DMO price may not be such that retailers can fully recover their costs.²¹ Retailers also raised this point in the workshops as particularly relevant for smaller retailers, who may have less ability to create efficiencies across the cost stack.

Retailers also expressed concern around efficiency and cost recovery with the introduction of the SSO and other consumer protection measures.

The AER is mindful this is a transitional phase for the DMO, with shifts in how the Regulations operate and impose obligations on retailers. The AER acknowledges the concerns raised by retailers and their views that these could be counteracted by including ‘headroom’ or an allowance for a cost stack element above an efficient level or some other sort of interim glidepath for DMO 8. 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.

However, the Regulations require the AER to balance a range of considerations when determining a ‘reasonable’ per-customer annual price for non-regulated and regulated tariffs, and tariff caps.²² The matters the AER must have regard to include:

¹⁹ ACCC and AER, [Joint compliance bulletin - Changes to the Electricity Retail Code](#), Australian Competition and Consumer Commission and Australian Energy Regulator, 20 April 2026.

²⁰ Origin Energy, [Submission to DMO 8 issues paper](#), 1 December 2025, p. 1; South Australian Department for Energy and Mining, [Submission to DMO 8 draft determination](#), 15 April 2026, p. 1; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 2; SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, p. 4.

²¹ AEC, [Submission to DMO 8 issues paper](#), Australian Energy Council, 26 November 2025, p. 1; AGL, [Submission to DMO 8 issues paper](#), 1 December 2025, pp. 1–3; Australian Energy Council, 26 November 2025, p. 1; Alinta Energy, [Submission to DMO 8 issues paper](#), 28 November 2025, pp. 1–2; EnergyAustralia, [Submission to DMO 8 issues paper](#), 28 November 2025, pp. 1–2; ENGIE, [Submission to DMO 8 issues paper](#), 26 November 2025, p. 1; Hum Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 4–5, 7–11; Origin Energy, [Submission to DMO 8 issues paper](#), 1 December 2025, p. 1; Powershop, [Submission to DMO 8 issues paper](#), 28 November 2025, pp. 1–2.

²² Regulations, ss. 16(1)(b), (1A)(b) and (1A)(c).

- the efficient costs of supply
- the long-term interests of consumers
- wholesale, distribution and transmission, and compliance costs, along with the modest cost of acquiring and retaining small customers
- the objective of providing small customers with a fair, trusted and reasonably priced electricity option that reflects the costs of supply.

In having regard to efficient costs, the AER's general approach is to consider the efficiency of cost elements individually. We consider this ensures consumers are not paying more than they need to while also allowing retailers to recover efficient costs, including an efficient margin, to enable the market to remain competitive and innovative. This approach is consistent with the Explanatory Statement, which states:²³

A key change arising from the Amendment Regulations is that only the efficient costs to supply small customers on standing offers are included when determining retail electricity prices. This reinforces the purpose of the Electricity Retail Regulations as a price protection for small customers, as articulated in the policy objective. This means only modest costs associated with customer acquisition and retention should be included, and that any competition allowance (or headroom) should be excluded when determining retail cost estimates for standing offers.

The chapters that follow demonstrate how we have had regard to the efficient costs to supply customers on standing offers, along with the other mandatory considerations, and reflected this in the final determination.

3.4 New DMO guideline

The Regulations require the AER publish a 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 the guideline to be published by 1 December 2026. This final determination has flagged some issues that will form part of the consultation for development of the guideline.

3.5 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.²⁴ However, for those with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms.²⁵ Customers seeking a standing offer can make that request of their existing retailer,

²³ Explanatory Statement, Purpose and Operation (p. 2), and items 39–44. See also DCCEEW, [Review Outcomes: 2025 reforms to the Default Market Offer](#), Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 8.

²⁴ National Energy Retail Law ss. 23 and s. 25.

²⁵ National Energy Retail Law s. 22.

knowing it will be met and that they will be protected by the DMO price cap. Retailers must ensure they comply with this obligation.²⁶

See Figure 3.2, which details circumstances in which a customer may be on a standing offer.

Figure 3.2 Standing offer customers^{27 28 29}



In distribution networks where the DMO applies, a minority of residential and small business customers are on standing offers. Table 3.1 shows 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.

²⁶ ACCC and AER, [Joint compliance bulletin - communicating pricing changes](#), Australian Competition and Consumer Commission and Australian Energy Regulator, May 2023.

²⁷ 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.

²⁸ 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.

²⁹ National Energy Retail Law s. 23 and s. 25.

Table 3.1 Current customers on standing offers in DMO regions

Customer type	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	249,958 (7.1%)	158,972 (10.1%)	66,230 (7.9%)	475,160 (8.0%)
Small business customers	44,551 (14.4%)	19,164 (16.1%)	13,367 (15.2%)	77,082 (15.0%)

Note: SE Queensland figures extrapolated from all of Queensland by excluding Ergon Energy customers. Other retailers have customers in regional Queensland, so Queensland figures are approximate. Standing offer customers have been calculated by subtracting market offer customers from total customers.

Source: AER retail market performance update, Quarter 2 2025–26.

3.6 Solar Sharer Offer

The Regulations have introduced a new regulated tariff category under the DMO framework called the 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 usage period. Retailers with more than 1,000 customers across all DMO regions must offer an SSO standing offer tariff.

However, the SSO standing offer tariff cannot be used as the default standing offer.³⁰

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).

³⁰ Regulations, s. 11(2).

4 Wholesale energy costs

For the DMO 8 final determination we have decided to:

- use only interval meter controlled load as the basis for our forecast controlled load profile
- adopt the 50th percentile wholesale energy cost (WEC) estimate and apply a volatility allowance
- not include the Australian Securities Exchange's (ASX) new morning and evening peak contracts in the simulated hedging strategy
- calculate time of use WECs based on the ratio of the demand-weighted price in the specific time of use charging window to the demand-weighted price for the overall load profile.

Wholesale costs represent approximately 30% to 41% of the total DMO price and have decreased 2% to 14% since DMO 7.

The Regulations require us, when determining a DMO price, to have regard to certain matters including the wholesale cost of electricity in the region, efficient costs, the long-term interests of consumers and the DMO objective.³¹

As discussed in chapter 3, 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 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 Draft determination

4.1.1 Controlled load methodology

In previous determinations the wholesale modelling has relied on AEMO's sample Controlled Load Profile, based on accumulation meters, to forecast controlled load demand. The profile was discontinued for NSW in 2024 and South Australia in 2025, with Energex being the only DMO region where it is still available. To address the lack of recent data, our draft determination used only interval meter controlled load data provided by relevant DNSPs to model controlled load demand and to apply this approach uniformly to all DMO regions, including Energex. This decision was made with consideration to reflect market outcomes, data transparency, the longevity of the approach and the continuity between determinations.

³¹ Regulations s. 16(4).

We also considered stakeholder feedback, which mostly supported exclusively using interval meter data.

We considered this approach resulted in the most accurate reflection of market outcomes. The controlled load profiles used in the draft determination demonstrated that interval meter controlled load typically has higher midday demand than indicated by the historical accumulation meter sample controlled load profile. Since more than half of controlled load customers have an interval meter, we considered this dynamic important to reflect in our simulated controlled load demand profiles. We ensured the decision was transparent by publishing the interval meter controlled load profiles provided by DNSPs.

We also considered this approach will have the best longevity of any available option, because most controlled load customers already have an interval meter and this proportion will continue to increase toward 100% by 2030.³² Use of interval meter controlled load data exclusively also ensures this decision will not need to be reviewed or changed in the foreseeable future. Conversely, options to blend the interval meter controlled load profile with discontinued accumulation meter controlled load profiles or the Net System Load Profile would have required ongoing review and reconsultation.

This option also provides the most continuity between determinations because it maintains the use of a controlled load profile while increasing the size and market reflectivity of the sample.

4.1.2 Percentile WEC estimate and volatility allowance

Our draft determination proposed to adopt the 50th percentile of modelled wholesale cost outcomes (WEC) and apply a volatility allowance for residential and small business customers. The volatility allowance was included to reflect the cost of holding capital to cover forecast risk. We proposed to calculate the volatility allowance by multiplying the difference between the 100th and 50th percentiles by a weighted average cost of capital (WACC) of 10%. The volatility allowance was included as a variable cost component. In line with our approach from the draft determination on the apportionment of fixed and variable costs (chapter 9), it was allocated to the usage charge of the DMO tariff caps.

This decision was reached by considering the results of the back-cast analysis detailed in *Assessing the performance of the wholesale cost model*,³³ along with stakeholder feedback to the issues paper. The analysis calculated retrospective WECs by settling assumed hedging strategies from prior DMO determinations against actual spot price and load outcomes. The analysis found the 75th percentile estimate adopted in previous determinations had typically resulted in overestimations of the WEC, while smaller underestimations had occurred in a minority of instances. It also showed that adopting the 50th percentile would have reduced the size of the overestimations while still providing retailers a buffer to recover efficient costs.

³² AEMC, National Electricity Amendment (Accelerating Smart Meter Deployment) Rule, Australian Energy Market Commission.

³³ AER, [Assessing the performance of the wholesale cost model](#), Australian Energy Regulator, 5 November 2025.

The 50th percentile, as the median forecast estimate, represents an even sharing of the risk between consumers and retailers that actual wholesale cost outcomes may differ from those forecast. We considered that the 50th percentile would usually enable most retailers to recover efficient costs while reducing the scale of overestimation and preserving retail competition, which is in the long-term interest of consumers.

We acknowledged the concerns of retailers in submissions to the issues paper, which noted that the WEC had been underestimated in a minority of instances at the 50th percentile. We considered this may have especially adverse outcomes for smaller retailers, who can experience scale and capital constraints that limit their hedging efficiency and strength of balance sheets. Therefore, we decided to include a volatility allowance in the draft determination to provide for potential differences in actual costs compared with those forecast.

4.1.3 Other wholesale cost issues

The draft determination maintained the methodology from DMO 7 to use a gross load profile derived from a blend of interval meter and accumulation meter datasets to forecast retailer load in wholesale modelling. This reflects the position we have maintained in previous determinations – that the DMO is a price charged for customers' consumption – and the load profile used in the modelling should reflect this. We did not consider that the new Regulations warranted any change in our approach and did not receive any stakeholder submissions to our issues paper related to this matter.

Our draft determination proposed to not include the ASX's new morning and evening peak contracts in the modelled hedging strategy for DMO 8, having considered stakeholder feedback and the lack of traded volume. This approach was supported by stakeholders.

Our draft determination adopted the same method as the Queensland Competition Authority to calculate time of use WECs for time of use DMO tariff caps. The load profile was divided into time periods based on the assumed time of use network tariff in all regions. Then a ratio for each period was calculated based on the demand-weighted price for the period compared with the overall load profile. The WEC was then scaled based on the ratios for each period. This approach to determine usage charges for each time of use period was selected because it is objective, transparent and straightforward. It also reflects the varying wholesale costs throughout the day and ensures the sum of the periodic WECs is the same as the total across the demand profile.

4.2 Stakeholder views

4.2.1 Controlled load methodology

We did not receive any stakeholder feedback about our controlled load methodology in response to the DMO 8 draft determination.

4.2.2 Percentile WEC estimate and volatility allowance

Percentile WEC

Consumer groups and the South Australian Department for Energy and Mining supported our draft determination to reduce the WEC from the 75th to the 50th percentile.³⁴ The JEC, ACOSS and Energy Consumers Australia (ECA) considered that even sharing of risk reflects a more reasonable modelling assumption.³⁵ Noting the conflict in the Middle East, the JEC and ACOSS recommended that the AER only make changes to the wholesale modelling if justified under observable data, rather than adjusting the percentile estimate upward to account for the conflict.³⁶

Retailers did not support adoption of the 50th percentile. Most recommended a return to the 75th percentile and a minority recommended a percentile higher than the 75th.

The Australian Energy Council (AEC) and several retailers considered that even sharing of forecast risk between retailers and consumers through the 50th percentile fails to capture how wholesale cost risks are distributed in practice.³⁷ Some retailers submitted that the risks of underestimating wholesale costs are more severe for retailers than the risk of overestimation for consumers, since retailers may face insolvency in extreme cases of WEC underestimation.³⁸ They considered this dynamic should be reflected by the percentile estimate chosen.

The AEC stated ‘If the benchmark is set too high, then the minority of customers on the DMO will pay slightly more than otherwise... Conversely, if the benchmark is set too low, retailers will be unable to recover their costs and at the margins, some risk going under’.³⁹ EnergyAustralia characterised the risk to consumers as ‘diffuse’, ‘recoverable’ and involving payment of ‘modestly more than efficient costs’.⁴⁰ Alinta Energy and ENGIE noted that the exit of multiple retailers from the market in 2022 serves as an example of the risk to retailers presented by the prospect of under-recovery.⁴¹

³⁴ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 5–6; SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, p. 11; South Australian Department for Energy and Mining, [Submission to DMO 8 draft determination](#), 15 April 2026, pp. 1–2.

³⁵ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 5–6; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, pp. 3–6.

³⁶ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 6.

³⁷ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 3–4; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–5; Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–8; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–6.

³⁸ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 3–4; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–8; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp.3–6.

³⁹ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 3–4.

⁴⁰ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–8.

⁴¹ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2.

Several retailer submissions considered that the outbreak of conflict in the Middle East is likely to significantly increase wholesale market volatility and risk, necessitating an increase in the percentile estimate.⁴² Most retailer submissions that mentioned the conflict noted that it increases the likelihood that DMO 8 relevant contract prices may rise substantially after the final determination date, leaving retailers exposed to these changes, but unable to increase their prices. Many retailers submitted that, regardless of the conflict, contract prices tend to rise post-determination by more than they fall, often citing the 2022 market events as an example.⁴³ ENGIE noted that the AER reduced the WEC percentile estimate from the 95th to 75th at that time, and that 7 non-vertically integrated retailers experienced Retailer of Last Resort events in the subsequent financial year.⁴⁴ Similarly, both AGL and Powershop referred to the mass exit of retailers from the UK electricity market following the global energy crunch in 2022.⁴⁵

ENGIE and Powershop also reiterated positions from their issues paper submissions. ENGIE considered the 50th percentile does not reflect an efficient hedging strategy and assumes retailers would not hedge against tail risk and volatility.⁴⁶ Powershop submitted that small retailers are more likely to be adversely impacted by the transition from 75th to 50th percentile since they may lack balance sheet depth or hedging flexibility.⁴⁷ Similar to submissions to the issues paper, many retailers noted that the wholesale market is volatile and unpredictable, creating severe tail risk against which retailers must hedge.

Volatility allowance

Consumer groups and the South Australian Department of Energy and Mining opposed inclusion of a volatility allowance, while retailers considered it should either be increased or replaced in favour of a return to the 75th percentile WEC.

Stakeholders that opposed the volatility allowance generally considered its inclusion contradicted the AER's position that forecast risk should be evenly shared between consumers and retailers.⁴⁸ They also considered it unnecessary, given the back-cast analysis indicated that overestimation of the WEC was both more common and larger on average than underestimation, even at the 50th percentile. The JEC, ACOSS, the South

⁴² Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2; Nectr, [Submission to DMO 8 draft determination](#), 8 April 2026, pp. 2–3; AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 3–4; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–4; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 5.

⁴³ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 3–4; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–4; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 5; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–8; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–5; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 7.

⁴⁴ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–4.

⁴⁵ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–5; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–6.

⁴⁶ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–4.

⁴⁷ Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–6.

⁴⁸ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 5–6; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 3; South Australian Department for Energy and Mining, [Submission to DMO 8 draft determination](#), 15 April 2026, pp. 1–2.

Australian Department of Energy and Mining, and ECA were also concerned about the extent to which the inclusion of the volatility allowance offset the decrease resulting from the reduction of the WEC percentile from the 75th to the 50th.⁴⁹

Some stakeholders expressed concern about the extent to which considerations of retail competition or retailer viability informed the decision to include the volatility allowance. The South Australian Department of Energy and Mining considered that while ‘the preservation of retail competition is critical to the long-term interests of consumers, we are concerned that the introduction of the volatility allowance imposes an unnecessary additional cost burden on consumers’.⁵⁰ ECA stated that differing risk profiles of various retailers should not be considered since a volatility allowance ultimately accrues to all retailers.⁵¹

ECA also recommended the method to calculate the volatility allowance be reconsidered and noted it was not clear what alternative methods the AER has considered.⁵² ECA considered that the proposed approach ‘results in a volatility allowance that is overly affected by outliers at the 100th percentile’.⁵³

All retailers considered it critical to continue to include the volatility allowance if the 50th percentile WEC were to be retained for the final determination. However, most considered that the volatility allowance as calculated in the draft determination was insufficient. Origin Energy was the only retailer to express support for the volatility allowance’s calculation.⁵⁴

Retailers’ most common criticism of the volatility allowance was that it would be insufficient to mitigate instances of underestimation. Alinta Energy noted that the allowance would not have covered the underestimation that occurred as a result of the 2022 market events.⁵⁵ Similarly, EnergyAustralia considered the allowance flawed because it is based on variation across simulations with fixed contract prices, and therefore unable to reflect scenarios like 2022, when contract prices rose by up to \$20 per MWh after the final determination.⁵⁶ Hum Energy considered the allowance modest relative to the range of potential wholesale outcomes.⁵⁷ AGL suggested that if the volatility allowance is retained it should reflect ‘real funding and margining requirements’.⁵⁸

⁴⁹ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 5–6; South Australian Department for Energy and Mining, [Submission to DMO 8 draft determination](#), 15 April 2026, p. 2; Energy Consumers Australia, 10 April 2026, pp. 3–4.

⁵⁰ South Australian Department for Energy and Mining, [Submission to DMO 8 draft determination](#), 15 April 2026, p. 2.

⁵¹ Energy Consumers Australia, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–4.

⁵² Energy Consumers Australia, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–4.

⁵³ Energy Consumers Australia, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–4.

⁵⁴ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 8.

⁵⁵ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2.

⁵⁶ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 7–8.

⁵⁷ Hum Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 5–8.

⁵⁸ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–5.

EnergyAustralia suggested that the AER test the adequacy of the volatility allowance against historical data.⁵⁹ It considered that if this analysis were to demonstrate that the volatility allowance is materially insufficient to ameliorate observed instances of under-recovery, it should be revised upward for the final determination.⁶⁰ EnergyAustralia also disagreed that the volatility allowance's accumulation across years of WEC overestimation justifies its inability to cover a large underestimation in any individual year.⁶¹

4.2.3 Other wholesale topics

We did not receive any stakeholder feedback about use of a gross load profile, new morning and evening peak contracts or time of use WECs in response to the DMO 8 draft determination.

The Shopping Centre Council of Australia (SCCA) considered that the wholesale methodology had changed significantly since DMO 7. It noted that embedded network operators do not procure energy in the same way as electricity retailers, so are less able to adapt to more specific wholesale pricing and DMO benchmarks.⁶² The SCCA recommended we revert to our DMO 7 wholesale methodology.

4.3 Final determination

4.3.1 Controlled load methodology

Our final determination maintains the draft determination approach to only use the interval meter controlled load data to model controlled load demand. This approach will apply uniformly to all DMO regions, including Energex. This approach received the most stakeholder support following the DMO 8 issues paper, with no additional feedback being provided after the draft determination.

4.3.2 Percentile WEC estimate and volatility allowance

Our final determination maintains the approach from our draft determination to adopt the 50th percentile WEC estimate and include an additional volatility allowance. The volatility allowance will be derived using the same calculation method as in the draft determination.

The 50th percentile represents the median forecast cost outcome and, therefore, the expected cost of prudent hedging based on all available information. As such, it provides the best estimate of efficient costs, rather than incorporating a higher percentile estimate that exceeds expected costs. Additionally, we consider that the choice of WEC 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.

⁵⁹ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 7–8.

⁶⁰ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 7–8.

⁶¹ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 7–8.

⁶² Shopping Centre Council of Australia, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 3.

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 maintain 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 and thus aligned with the long-term interests of consumers, which we must consider under the Regulations.⁶³ Therefore, we have included a volatility allowance to facilitate retailers holding capital to manage the risk that wholesale costs may be underestimated.

We received a significant amount of feedback in response to our draft determination on this matter. In many cases, similar views were raised across different submissions. Below we respond to the feedback on an issue-by-issue basis to assist stakeholders in understanding how views were factored into our final determination.

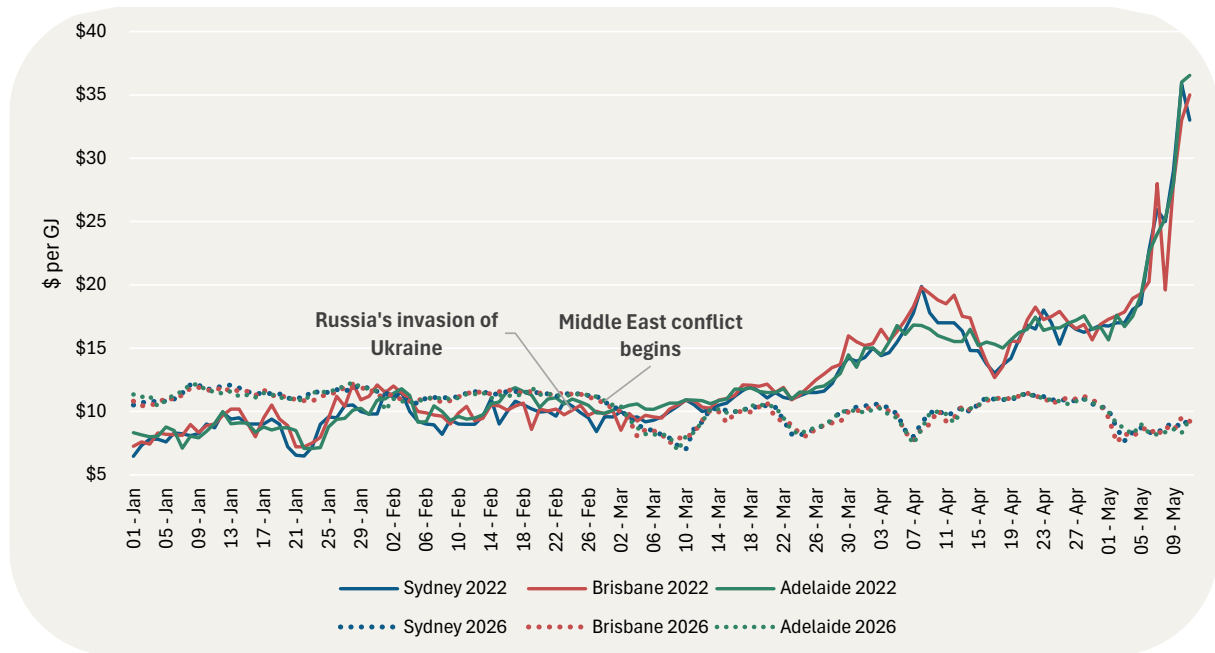
Impacts of the conflict in the Middle East

We accounted for the impact of the conflict in the Middle East through standard procedural updates to modelling inputs, including fuel and contract prices, which reflect changes in the forward curve of relevant contract prices in the months following the conflict's commencement. We consider that relying on current market forecasts in the wholesale modelling is the best way to ensure potential impacts are captured, without disproportionately allocating forecast risk to consumers by adopting a higher percentile estimate.

We acknowledge retailers' views that the Middle East conflict could pose solvency risks if market outcomes for fuel and contract prices were like those observed after Russia's invasion of Ukraine in 2022. While we agree the level of uncertainty in the outlook has increased, neither spot market nor forward prices indicate that the market expects impacts similar to those observed in 2022. At the time of writing, gas spot prices on the east coast are between 11% and 14% lower than on the date of the Middle East conflict's commencement, and have been stable compared with their response to Russia's invasion of Ukraine in 2022 (Figure 4.1).

⁶³ Regulations ss. 16(4)(ba).

Figure 4.1 Gas Short Term Trading Market ex ante prices, 2022 comparison with 2026

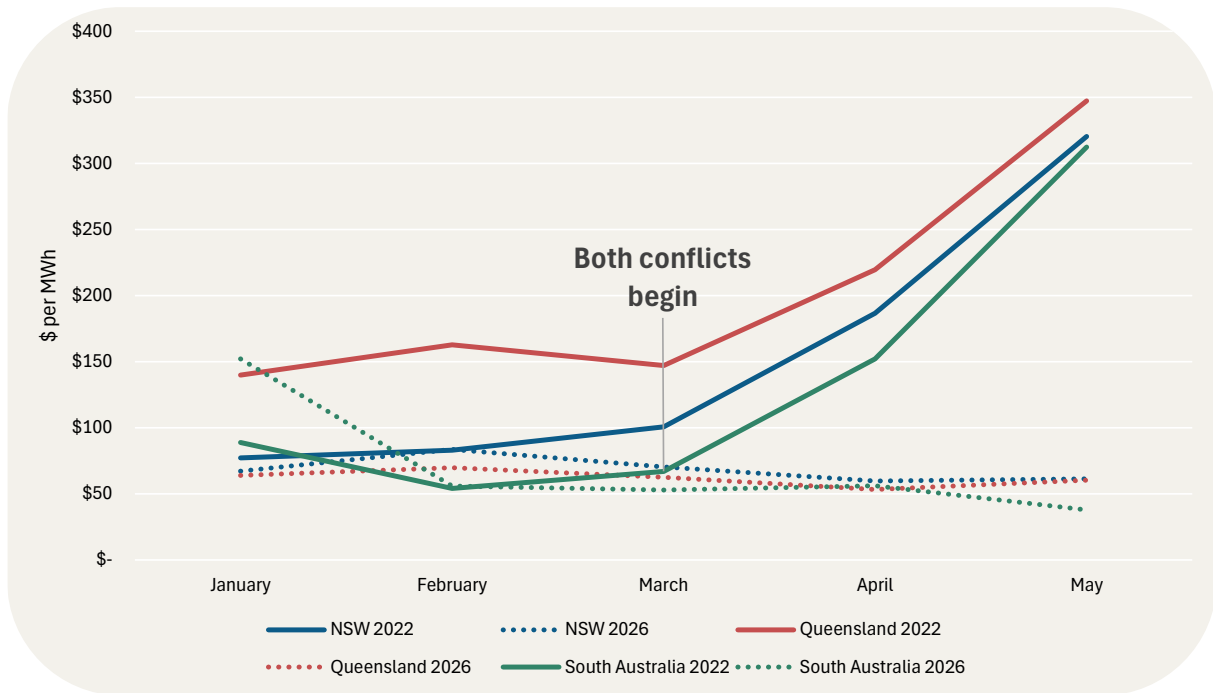


Note: Data from each year has been aligned by day and month to enable a like-for-like comparison from the start of each period. The Short Term Trading Market operates on a consistent weekend trading cycle, ensuring trading days align naturally across years.

Gas is both significantly lower priced than in 2022 and setting the prices in the NEM less frequently, limiting exposure to international fuel prices.⁶⁴ This is evident in electricity spot prices, which have not been discernibly impacted by the conflict and have fallen since it began. Average spot prices across April 2026 were less than half of those observed in 2022 (Figure 4.2).

⁶⁴ AEMO, [Quarterly Energy Dynamics, Q4 2025](#), Australian Energy Market Operator, p. 4; AEMO, [Quarterly Energy Dynamics, Q1 2026](#), Australian Energy Market Operator, p. 16.

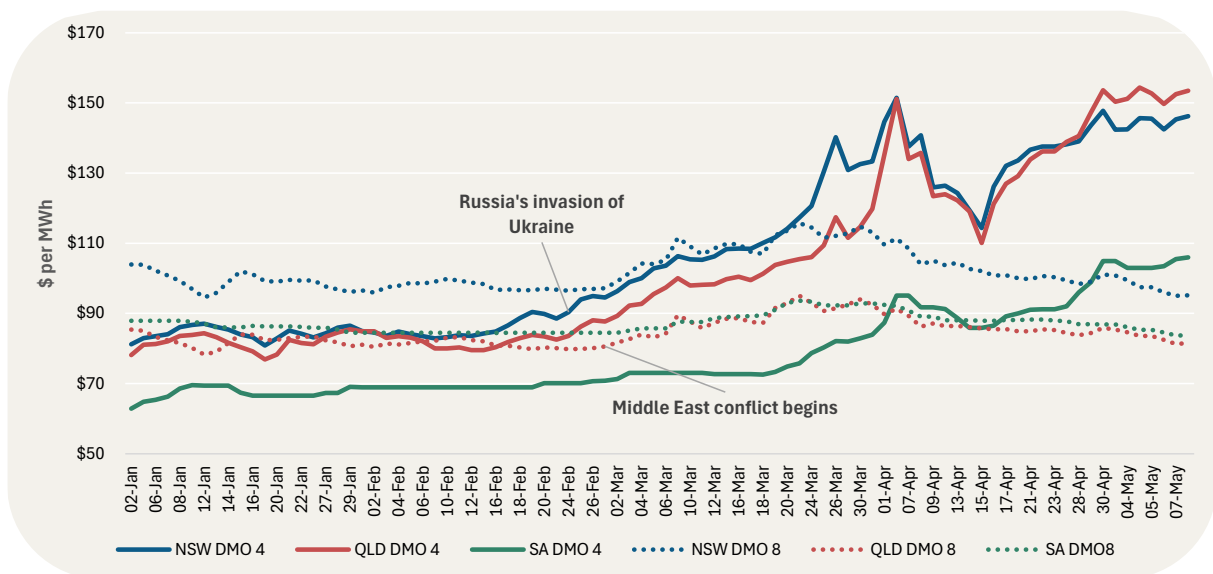
Figure 4.2 Monthly average NEM spot prices in DMO regions, 2022 versus 2026



Note: Data from each year has been aligned by day and month to enable a like-for-like comparison from the start of each period. The NEM operates on a consistent weekend trading cycle, ensuring trading days align naturally across years. Averages for May 2026 are partially incomplete, due to this determination’s publication before the month’s end.

These subdued market conditions are being reflected in DMO 8 relevant contract prices, which have been notably more stable than DMO 4 relevant contracts were in 2022. Despite a steep increase immediately following the beginning of the conflict, base futures prices have moderated and, at the time of writing, were trading 2% below to 1% above pre-conflict levels. This is notably more stable than the near exponential increases observed for DMO 4 contracts immediately following Russia’s invasion of Ukraine (Figure 4.3).

Figure 4.3 Electricity base futures prices, 2022 comparison with 2026



Note: The x-axis is 2026 ASX trading dates. Given ASX markets do not trade on weekends or public holidays, minor date misalignments of no more than 2 days occur between 2022 and 2026 series in some places.

We consider these developments in contract prices reflect the aggregate expectations of market participants, including retailers. The absence of a sustained and material uplift in futures prices suggests the market is not currently expecting material increases in wholesale price outcomes. As such, we do not consider there is a basis for raising the percentile estimate to disproportionately allocate the forecast risk posed by the conflict to consumers, where that risk has not translated to a sustained uplift in publicly traded contract prices.

We also see evidence that existing inputs are adequately reflecting the uncertainty posed by the conflict, with the higher coal price input having directly impacted the volatility allowance by increasing the spread between the 50th and 100th percentiles in NSW regions. We consider this data-driven approach is preferable to adjusting the percentile estimate or the calculation method of the volatility allowance.

We note the Prime Minister also indicated in a Press Club address on 2 April 2026 that ‘we will pursue every option to ensure that increases that might be there in coal and gas prices do not flow into electricity prices’.⁶⁵

Allocating risk on a symmetrical or asymmetrical basis

We acknowledge that, in extreme cases, if the DMO benchmark substantially underestimates actual wholesale costs it could be a factor in a retailer’s ongoing viability. However, we consider that retailer submissions materially understated the risk of WEC overestimation and the harm to consumers this can cause.

Overestimation would cause consumers to pay more than necessary for an essential service in a period of mounting cost-of-living pressures. Our most recent *Retail energy market quarterly performance report* highlights that 4.3% of residential customers are in energy debt and the average debt of hardship customers has increased by 22.8% since the previous year.⁶⁶

Retailers also have more options available to them to manage wholesale cost risk than consumers, including methods not accounted for in the DMO’s wholesale methodology. These include vertical integration and internal generation, demand response programs, virtual power plants and bespoke hedging products. Conversely, consumers operating under significant budget constraints have the option of reducing consumption of electricity or other essentials. A 2025 ACOSS survey found that 50% of respondents reported skipping meals and other essentials to pay their energy bills, while 69% reported reducing cooling despite extreme heat.⁶⁷ These trade-offs are not hypothetical downsides that may occur in the event of an extreme WEC forecast error; they are observable outcomes already occurring under current price settings.

Deviation of contract prices following the setting of the DMO determination

When discussing how post-determination contract price deviation should impact the percentile estimate chosen, retailer submissions referred mostly to movements in DMO 4

⁶⁵ The Hon Anthony Albanese MP, [Address to the National Press Club](#), 2 April 2026.

⁶⁶ AER, [Retail energy market quarterly performance report](#), October–December 2025, Australian Energy Regulator, 2 April 2026.

⁶⁷ ACOSS, [Heat in homes survey report 2025](#), Australian Council of Social Service, 13 March 2025, pp. 40–46.

contract prices after the 2022 determination and some to the wider back-cast period (DMO 2 to DMO 6). As noted in the back-cast analysis, the period surveyed coincided with historically elevated levels of volatility.⁶⁸ The significant post-determination contract price variations referred to in the retailer submissions are an anomaly when compared with longer-term ASX data. As such, we consider the 50th percentile combined with the volatility allowance remains appropriate to manage forecast risk.

Adequate hedging of spot price risk

In response to ENGIE’s concern that the 50th percentile assumes retailers would not hedge against tail risk and volatility, we refer to our response to this same concern in our draft determination.⁶⁹ We explained that the modelled hedging strategy is the same at all percentiles. Further, we explained that the hedging strategy is calibrated after all spot market simulations are completed and designed to minimise variation in WEC across all of them. Therefore, the hedging strategy is designed to protect against the full distribution of forecast spot price outcomes, including the most volatile, regardless of the percentile selected.

Amount of the volatility allowance

Some retailer submissions considered the volatility allowance flawed because it would not fully ameliorate observed instances of under-recovery.⁷⁰ We consider the purpose of the volatility allowance is not to fully offset underestimation in all previous back-cast outcomes. Instead, the volatility allowance compensates retailers for the efficient cost of holding capital to manage forecast risk across the full distribution of forecast outcomes. Designing the allowance to fully mitigate tail-risk events would make it functionally equivalent to adopting the 100th percentile WEC. This would compensate retailers for a significantly more volatile than expected outcome in every year, despite the back-cast analysis indicating that underestimation is both less frequent and typically smaller than overestimation.

The approach of applying the WACC to the difference between the 50th percentile and the highest forecast WEC reflects the financing cost of managing tail risk without meaningfully shifting allocation of forecast risk between consumers and retailers away from neutral.

We have undertaken back-testing of the volatility allowance against historical data as suggested by EnergyAustralia, which also recommended the allowance be increased if it is found not to fully offset observed instances of under-recovery.⁷¹ The results indicate that, while the volatility allowance would not fully ameliorate any individual instance of under-recovery, its most common impact was to increase instances of overestimation. Figure 4.4 and Figure 4.5 show the impact of the volatility allowances in regions where underestimations occurred (the 3 regions where no underestimation occurred have been excluded).

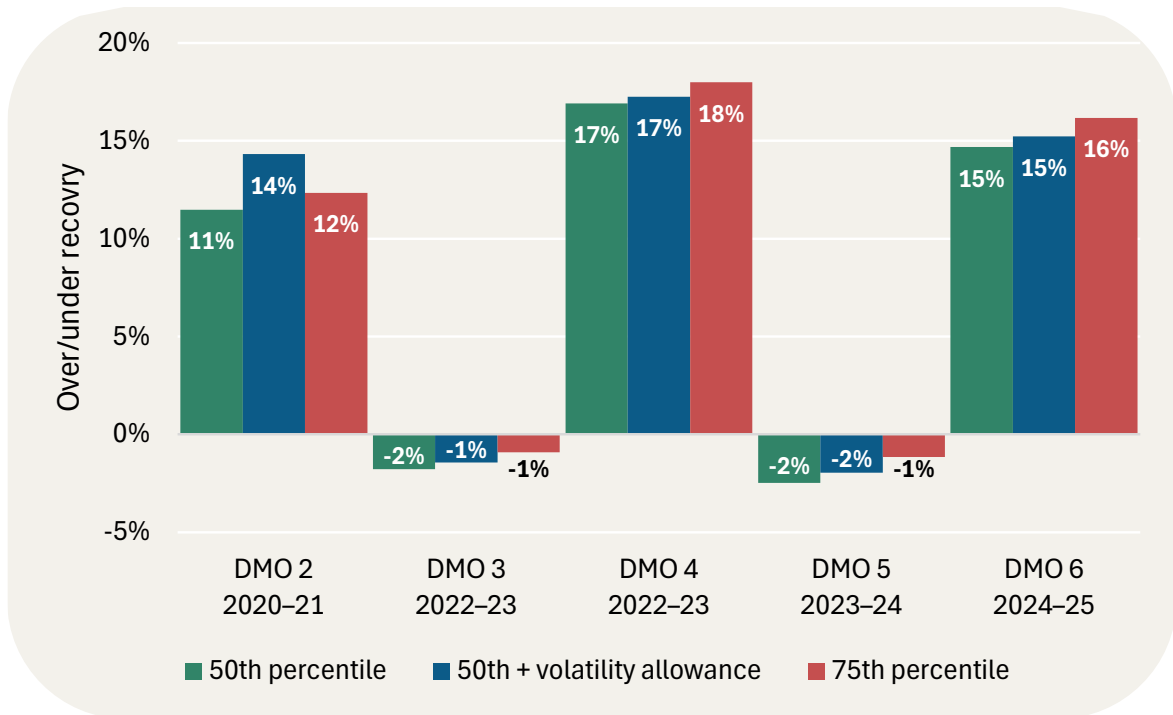
⁶⁸ AER, [Assessing the performance of the wholesale cost model](#), Australian Energy Regulator, 5 November 2025.

⁶⁹ AER, [Draft determination – Default market offer prices 2026–27](#), Australian Energy Regulator, pp. 47–48.

⁷⁰ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 7–8; Hum Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 8.

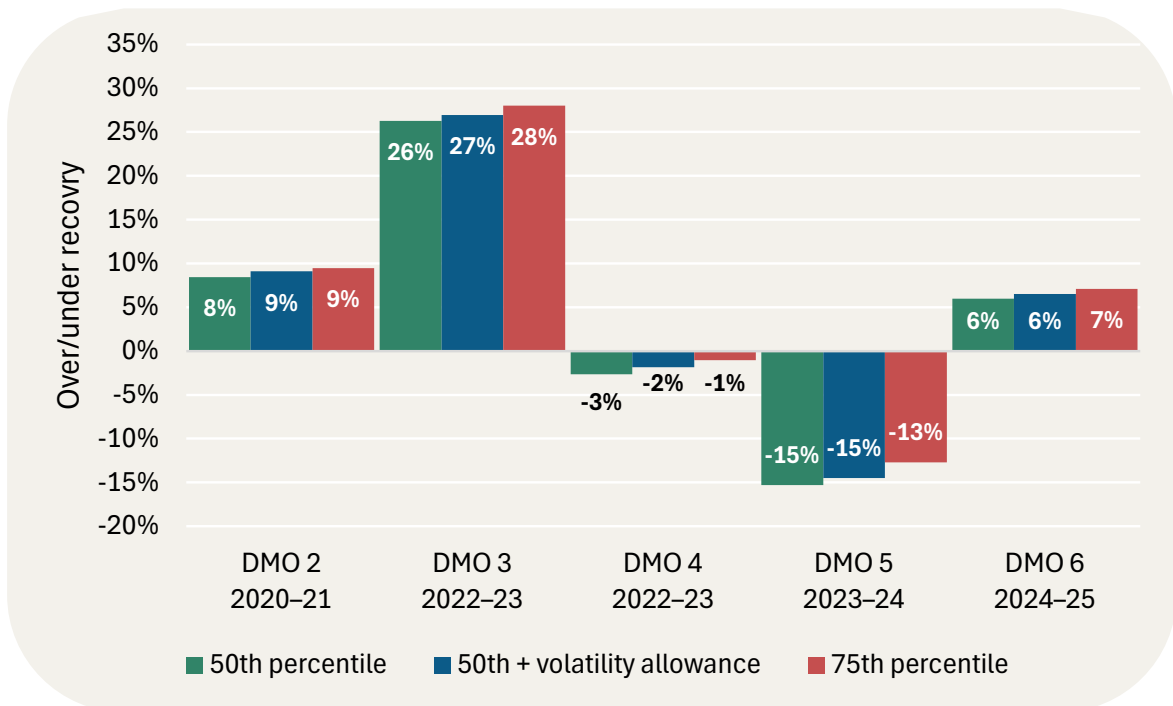
⁷¹ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 7–8.

Figure 4.4 Recovery by the modelled retailer against the actual WEC, Essential Energy



Note: A positive number represents over-recovery by the modelled retailer, while a negative number represents under-recovery. All results are compared with the actual WEC calculated in the back-cast analysis. In DMO 2, the combination of the 50th percentile plus the volatility allowance is greater than the 75th percentile, which was caused by the 100th percentile being significantly greater than other percentiles. As can be observed in the figure, this issue was resolved from DMO 3 onwards.

Figure 4.5 Recovery by the modelled retailer against the actual WEC, Energex



Note: A positive number represents over-recovery by the modelled retailer, while a negative number represents under-recovery. All results are compared with the actual WEC calculated in the back-cast analysis. In DMO 2, the combination of the 50th percentile plus the volatility allowance is greater than the 75th percentile, which was

caused by the 100th percentile being significantly greater than other percentiles. As can be observed in the figure, this issue was resolved from DMO 3 onwards.

EnergyAustralia also disputed that the volatility allowance would accumulate across years (section 4.2.2), considering that retailers with weak balance sheets may not survive large instances of overestimation such as that which occurred in 2022. While we acknowledge this point, we consider the back-cast analysis indicates that retailers operating at efficient cost typically have the opportunity to accumulate capital reserves over time if they choose to, with the volatility allowance further supporting this outcome. We do not consider that calibrating the allowance to ensure that retailers with the weakest balance sheets can withstand the most extreme years is commensurate with the requirement to consider efficient costs. Instead, such an approach would result in an allowance that reflects the least efficient retailers managing the worst-case wholesale market outcome in every year and lead to frequent over-recovery from consumers.

Volatility allowance and the balance of forecast risk

We consider the current methodology evenly balances risk between consumers and retailers, despite the volatility allowance compensating retailers for the cost of holding capital to manage forecast risk. We consider that in typical years forecast risk is not biased in any particular direction, which makes the 50th percentile an appropriate benchmark WEC. However, the results of the back-cast analysis indicated that the WEC has been underestimated in a minority of years. In these instances, the WEC incurred by efficient retailers may be above the allowed recovery amount stipulated by the DMO. In such a situation, some efficient retailers may need to rely on capital reserves. We consider this balance is in the long-term interests of consumers because it facilitates retailer viability and competition.

Over the lifespan of the DMO, a volatility allowance would usually have been equivalent to adopting a WEC between the 57th and 59th percentiles. In DMO 8 it delivers around one-third of the uplift from the 50th to 75th percentile. We consider this allows for prudent management of forecast risk.

Regarding ECA's concern that the 100th percentile allows outliers to have undue influence on the volatility allowance, we consider that allowing for outliers is precisely the purpose of the volatility allowance.⁷² Retailers are exposed to such outliers when they occur and the back-cast analysis demonstrated this happened as recently as DMO 4. Compensating retailers for managing these outliers should strengthen their financial resilience, protecting retailer viability and retail competition, which are aligned with the long-term interests of consumers.

We also considered but ultimately did not adopt the methods for calculating the volatility allowance as proposed by ECA in its submission to the issues paper, and by EnergyAustralia in its submission to the draft determination. ECA proposed that the volatility allowance be subtracted from the WEC and based on prior observed instances of overestimation. EnergyAustralia recommended (in section 4.2.2) that the volatility allowance be revised upward such that it would offset prior instances of underestimation. In both cases the method proposed is essentially a redistribution of prior forecast error, with each stakeholder

⁷² ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, pp. 3–4.

recommending this redistribution apply in opposite directions. As stated in the draft determination, this would effectively amount to a true-up mechanism based on backward-looking estimates rather than actual costs incurred (which differ between retailers). We considered this would be problematic, given the purpose of a true-up mechanism is traditionally to replace estimates with actuals, not with an alternative estimate.

4.3.3 Other wholesale cost issues

Our final determination continues to use a gross load profile based on a blended dataset of interval meter and accumulation meter data. The interval meter datasets were published along with the DMO 8 draft determination.

We have not included the ASX's new morning and evening peak contracts in the modelled hedging strategy, given their lack of traded volume. We will continue to monitor the market in future determinations to assess whether inclusion of these products may be appropriate.

We have used the same method as the draft determination to derive time of use WECs. 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 has then been scaled according to these ratios in each time of use period. We divided 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 acknowledge submissions explaining that aspects of our wholesale methodology would not be readily applicable to embedded network retailers. Since the DMO does not currently apply to embedded network customers, we have not factored these issues specifically into the decisions on the wholesale methodology. However, we will consider them as part of the DMO guideline if the Regulations are extended to embedded network customers.

4.3.4 Summary of 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 2 (tariff code EA040) in the Ausgrid region.

Decreases have been driven by substantial falls in contract and spot market prices in all regions. In SA Power Networks this was partly offset by increases in ancillary service costs, along with a greater proportion of demand occurring during the evening peak. However, greater controlled load demand during daylight hours resulted in a strong fall for SA Power Networks' controlled load WEC. In Energex, proportionately lower peak demand amplified falling contract prices. 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 \$10.90/MWh and a decrease in cap contract prices of \$5.10/MWh
- for Queensland – a decrease in base futures contract prices of \$5.90/MWh and a decrease in cap contract prices of \$5.30/MWh
- for South Australia – a decrease in base futures contract prices of \$3.60/MWh and a decrease in cap contract prices of \$4.60/MWh.

Contract prices for the 2026–27 (DMO 8) financial year 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.⁷³ In the December quarter 2025, spot prices above the cap strike of \$300/MWh contributed \$3/MWh to the average price, down 85% from the same time the previous year.⁷⁴ The reduction in prices and volatility was driven by increased output from wind and battery generators, which has reduced reliance on gas and hydro capacity during evening demand peaks.⁷⁵ Though some higher spot price activity resumed in early 2026, prices have so far remained suppressed compared with historical averages.

Contract prices rose steeply in the period immediately following the beginning of the Middle East conflict, but the increase was brief, and prices ultimately returned to pre-conflict levels.

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. Queensland contract prices declined by less than in NSW, but the proportion of energy demanded during the evening peak decreased, further reducing the Energex WEC and resulting in overall wholesale cost decreases similar in size to NSW.

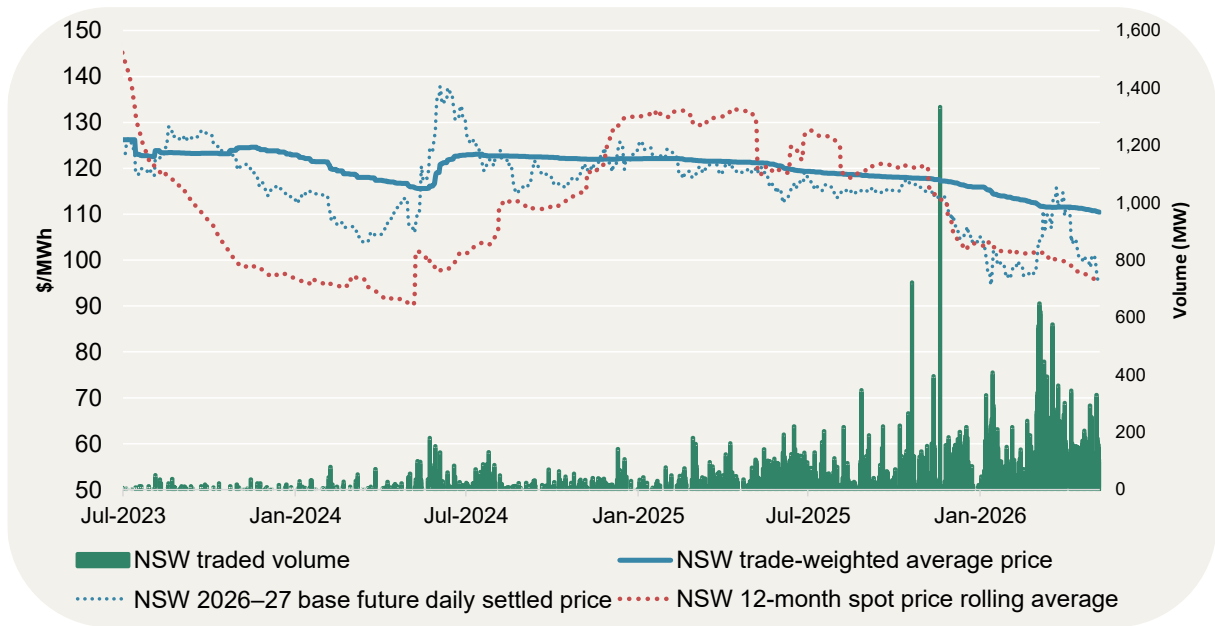
Volume traded since the outbreak of conflict in the Middle East has been included in the trade-weighted contract prices used in the wholesale modelling. However, most of this volume was traded at prices below the trade-weighted average, causing it to decrease further. Changes in fuel input costs since the outbreak of the conflict were also included in the modelling.

⁷³ AEMO, [Quarterly Energy Dynamics – Q4 2025](#), Australian Energy Market Operator, January 2026, pp. 12–13.

⁷⁴ AEMO, [Quarterly Energy Dynamics – Q4 2025](#), Australian Energy Market Operator, January 2026, p. 13.

⁷⁵ AEMO, [Quarterly Energy Dynamics – Q4 2025](#), Australian Energy Market Operator, January 2026, p. 1.

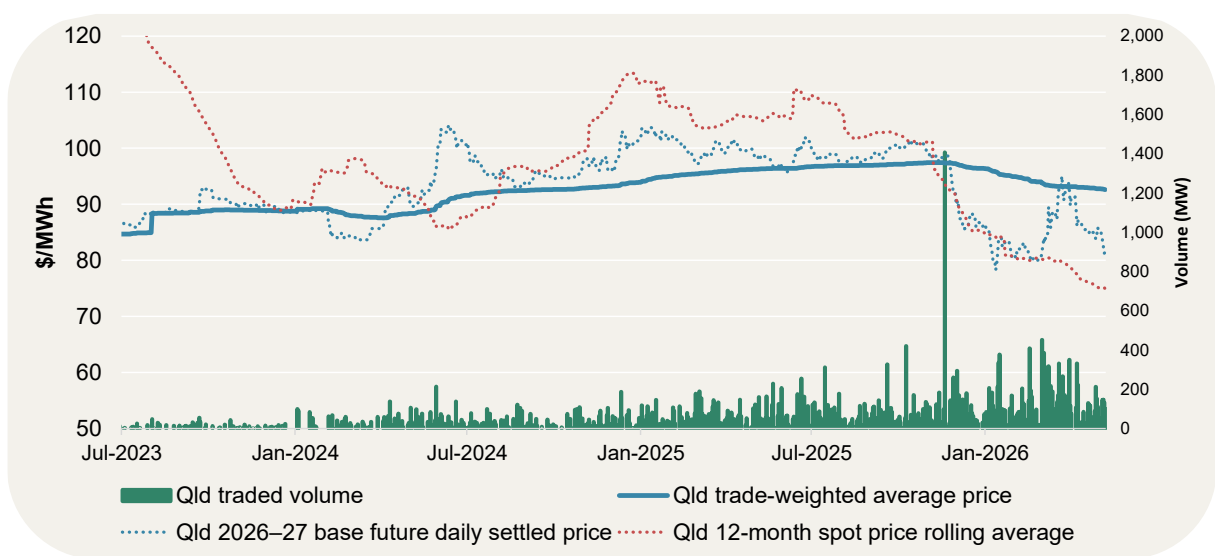
Figure 4.6 NSW base future daily settled price and trade-weighted average, 2026–27



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.

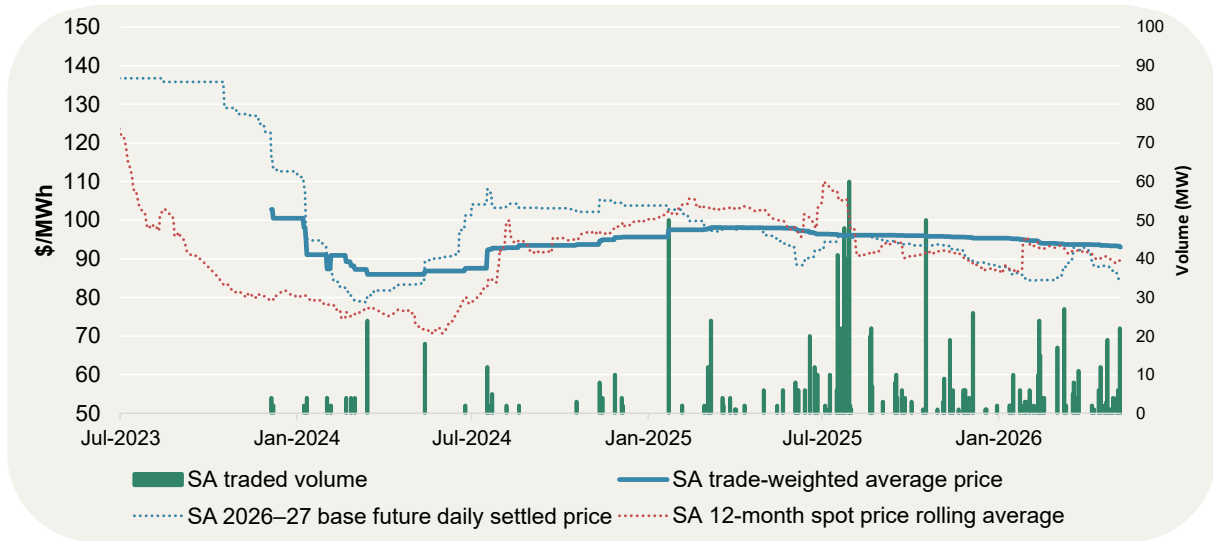
Figure 4.7 Queensland base future daily settled price and trade-weighted average, 2026–27



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.

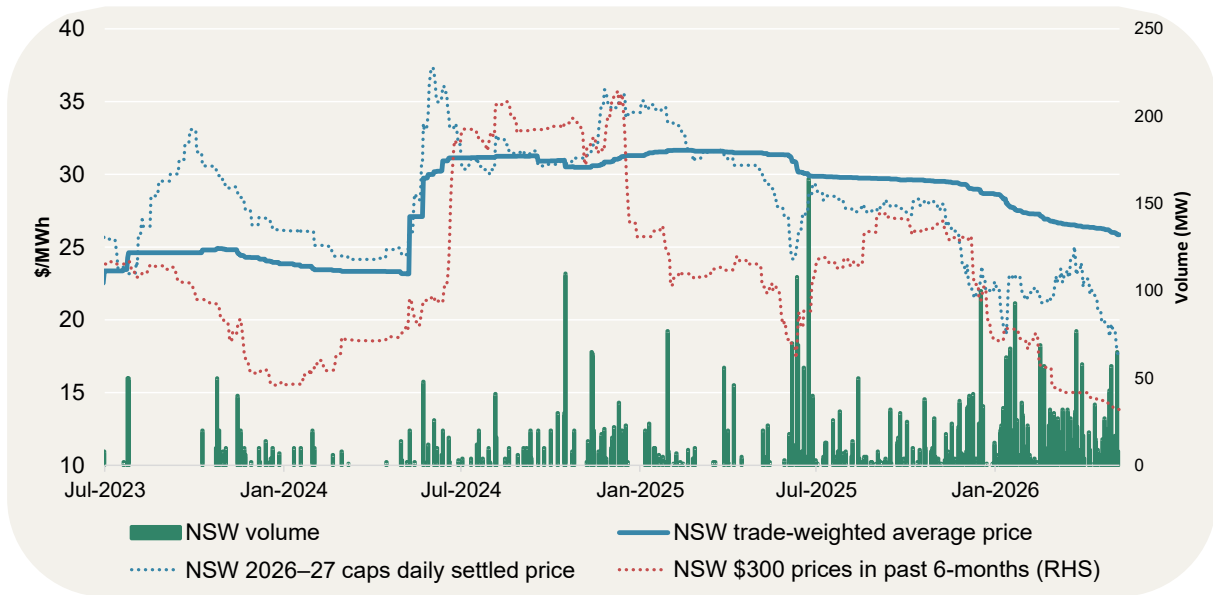
Figure 4.8 South Australia base future daily settled price and trade-weighted average, 2026–27



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.

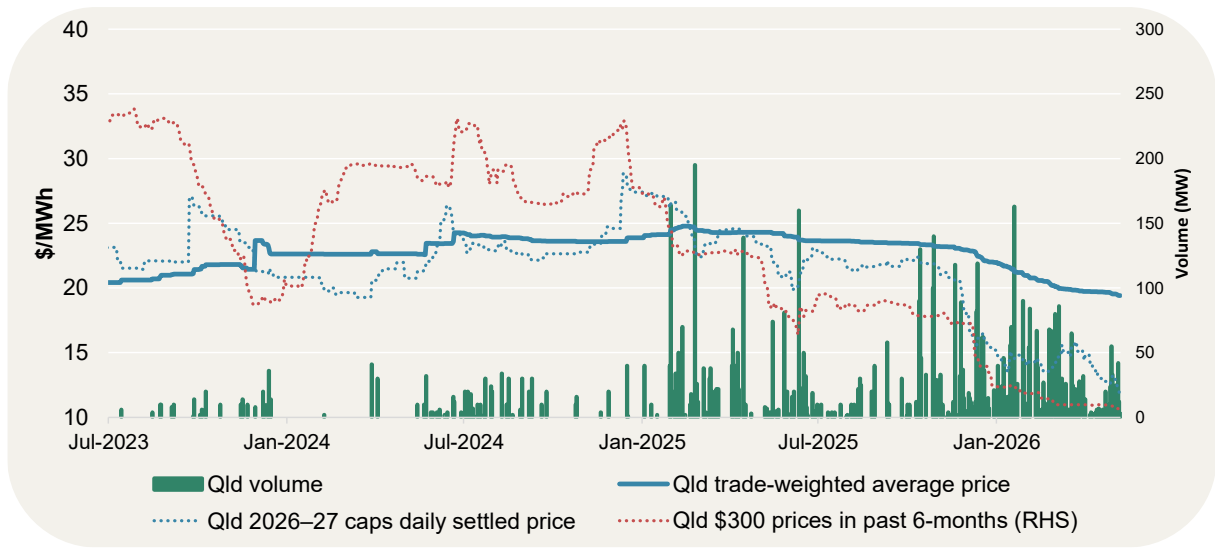
Figure 4.9 NSW cap daily settled price and trade-weighted average, 2026–27



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.

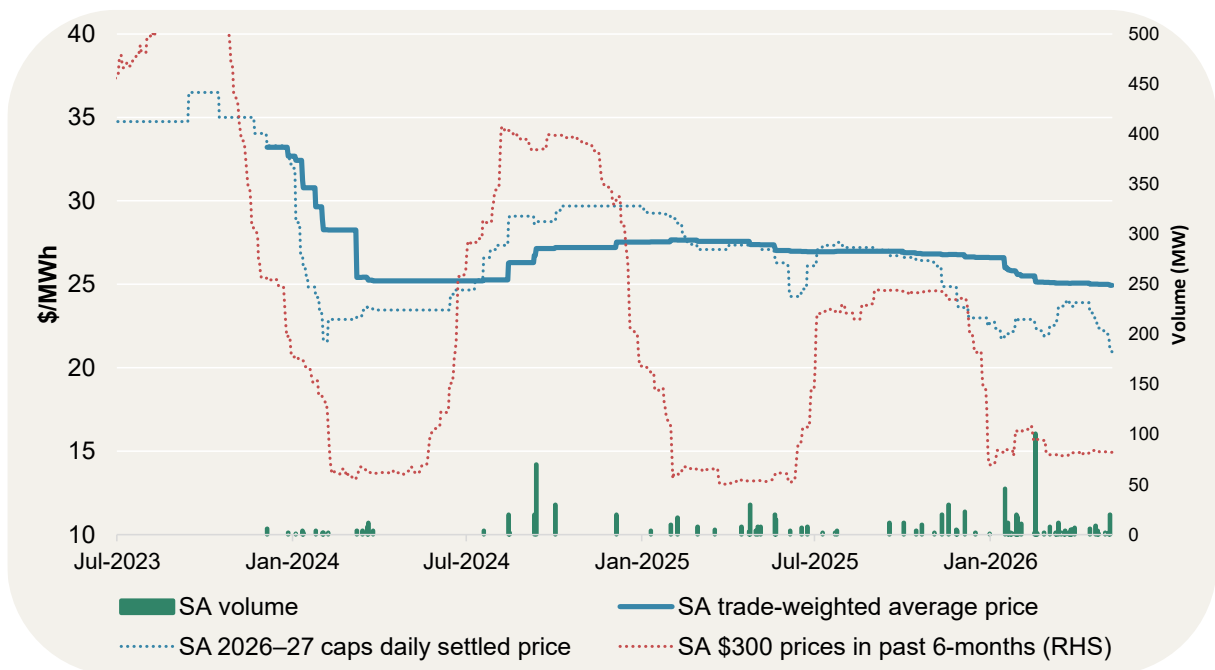
Figure 4.10 Queensland cap daily settled price and trade-weighted average, 2026–27



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 4.11 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.

Non-WEC components of the wholesale cost changed little in NSW and Queensland but increased by \$10.40/MWh in South Australia, driven by a combination of increases in ancillary services and energy losses. In South Australia, ancillary services rose by \$7.73/MWh driven mainly by lower-1-second FCAS costs, for which the spot 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.⁷⁶ Additionally, AEMO now primarily manages system security through voltage control, which is recovered from ancillary service costs, further contributing to the increase in that cost component.⁷⁷ Higher ancillary services costs were further compounded by an increase in energy losses, resulting in an overall increase of \$6.40/MWh. These increases were partly offset by a reduction in directions costs (–\$4.48/MWh)⁷⁸ and the falling WEC, resulting in a smaller wholesale cost decrease in South Australia relative to other regions.

Table 4.1 Wholesale costs for 2026–27 DMO 8 final determination, \$/MWh (variable costs, ex. GST, nominal)

Distribution region	Customer type	2025–26 (final)	2026–27 (final)	Change year-on-year
Ausgrid (NSW)	Flat rate	\$172.20	\$149.03	–13.5%
	CL1	\$124.58	\$124.26	–0.3%
	CL2	\$122.71	\$129.27	5.3%
Endeavour Energy (NSW)	Flat rate	\$182.42	\$159.22	–12.7%
	CL 1	\$130.29	\$116.99	–10.2%
	CL2	\$130.29	\$103.70	–20.4%
Essential Energy (NSW)	Flat rate	\$175.54	\$151.16	–13.9%
	CL1	\$123.89	\$123.83	–0.05%
	CL2	\$123.89	\$123.83	–0.05%
Energex (SE Queensland)	Flat rate	\$164.39	\$140.44	–14.6%
	CL1	\$113.10	\$105.59	–6.6%
	CL2	\$119.95	\$108.26	–9.7%
SA Power Networks (South Australia)	Flat rate	\$191.72	\$188.27	–1.8%
	CL1	\$120.19	\$97.82	–18.6%

⁷⁶ AER, [Electricity prices above \\$5,000 per MWh – July to September 2025](#), Australian Energy Regulator, 1 December 2025, pp. 10–15.

⁷⁷ AEMO, [Quarterly Energy Dynamics – Q1 2026](#), Australian Energy Market Operator, January 2026, p. 48.

⁷⁸ Between the draft and final determinations, we identified double counting arising from the inclusion of system security directions across multiple AEMO data sources used in our cost estimates (both directions and ancillary services costs). We have removed the associated costs from directions for system security.

5 Network costs

For the DMO 8 final determination we have decided to:

- not maintain the draft determination approach of applying the lowest applicable network tariff, be it the flat rate or time of use network tariff, for the DMO flat rate retail tariff and comparison price
- instead apply a blend of flat rate and time of use network tariffs for the DMO flat rate retail tariff and comparison price
- apply the time of use network tariffs for the DMO time of use retail tariff and comparison price
- 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.

Network costs represent between 39% and 54% of the DMO 8 final determination prices. Changes in the network component of the DMO prices range from decreases of 18.8% to increases of 10.6% since DMO 7, depending on region, customer type and whether a customer is on a flat rate or time of use retail tariff.

The Regulations require us, when determining a DMO price, to have regard to certain matters including the cost of distributing and transmitting electricity in the region, efficient costs, the long-term interests of consumers and the DMO objective.⁷⁹



In a retail electricity bill, network costs represent the cost a network distributor incurs in transporting electricity to a customer, as well as costs to safely manage these networks and measure electricity. Under the National Electricity Rules, the AER regulates network charges by approving the network tariffs that distribution network businesses set on an annual basis. Network charges typically comprise of:



Distribution Use of System (DUoS) charges

The recovery of regulated distribution revenues, reflecting the efficient costs of delivering safe and reliable electricity to customers and for managing the distribution network.



Transmission Use of System (TUoS) charges

The recovery of regulated transmission revenues, reflecting the efficient costs of delivering safe and reliable energy to distribution networks and for managing the transmission network.



Metering charges

Covers the maintenance, reading, data services and the recovery of capital costs for meters owned by the DNSP.



Jurisdictional schemes

The recovery of costs to support jurisdictional schemes, including (but not limited to) premium feed-in tariffs and renewable energy zones.

⁷⁹ Regulations s. 16(4).

5.1 Draft determination

Under the Regulations, the AER is required to set tariff caps and comparison prices for certain types of regulated tariffs,⁸⁰ including flat rate and time of use tariffs.⁸¹

Our draft determination sought to pass through the lowest cost applicable network tariff for the type of regulated retail tariff. We favoured passing through a single network tariff because it would promote transparency and predictability. Our draft determination noted that stakeholder views at the time supported a single network tariff rather than a blend of network tariffs.

5.1.1 Flat rate tariffs

For flat rate DMO tariffs and comparison prices, either the flat rate or time of use network tariff could apply. The availability of either network tariff for any given customer is largely due to whether they have a smart meter. Customers are now increasingly assigned a time of use network tariff when a smart meter is installed, but they may remain on a flat rate retail tariff for at least 2 years in some regions.⁸² Customers with legacy accumulation meters remain on flat network tariffs.

Given the availability of both tariffs, the draft determination proposed applying the lowest cost of either the flat rate or time of use network tariff to the flat rate retail tariff for each region. It also noted that retailers could arrange for smart meter installations, which would provide an incentive to assign the time of use tariff where it was the lowest.

At the time of the draft determination, our analysis showed the time of use network costs were lowest in the Essential Energy, Energex and SA Power Networks regions. For those regions, the time of use network tariff applied for the DMO flat rate tariff cap and comparison price. In contrast, in the Ausgrid and Endeavour Energy regions, our draft determination indicated the flat rate network tariffs were lowest. Therefore, we used those tariffs for the draft DMO flat rate tariff cap and comparison price.

However, submissions in response to the draft determination identified errors in how we applied the pattern of supply to the weighting of the peak, off-peak and shoulder network tariff windows. When these errors are corrected, time of use network tariffs are consistently the lower cost network tariff based on our assumed pattern of supply.

5.1.2 Time of use tariffs

For the DMO time of use tariffs and comparison prices and for all regions, we applied the underlying prices and structure of the applicable time of use network tariffs, which should allow retailers to recover network charges in a similar manner to how they are incurred. This

⁸⁰ Regulations, s. 16(1A).

⁸¹ Regulations, s. 5.

⁸² The accelerating smart meter deployment rule change requires retailers to obtain explicit informed consent when varying a customer's tariff structure. This requirement is in place for the 2-year period immediately following the replacement of a legacy meter at a customer's premises. See AEMC, [National Electricity Amendment \(Accelerating Smart Meter Deployment\) Rule](#), Australian Energy Market Commission, 28 November 2024.

supports the regulatory determination of a time-varying flexible retail tariff because passing through the time of use network tariff also passes through the time and pricing signals.

Our draft determination applied the applicable default time of use network tariff, as set out in network Tariff Structure Statements, in all regions except Ausgrid where the most common time of use network tariff will apply. The default network tariff in Ausgrid is a demand tariff and, under the Regulations, the DMO retail tariff cannot include demand charges.⁸³

5.1.3 Non-regulated tariffs

For non-regulated tariff comparison prices, the draft determination applied the time of use network tariff because we considered it best reflected the efficient costs retailers are likely to incur when supplying these offers. Non-regulated standing offers will often be flexible, using a smart meter and subject to a cost-reflective (that is non-flat rate) network tariff.

5.2 Stakeholder views

The majority of the feedback from stakeholders related to the approach to determining network costs for the DMO flat rate retail tariff caps and comparison prices. No submissions raised objections to the DMO time of use tariffs applying the corresponding time of use network tariff. SACOSS requested a more granular breakdown of network costs into distribution, transmission and jurisdictional scheme costs.⁸⁴

5.2.1 Choice of network tariff for DMO flat rate retail tariff

The JEC and ACOSS joint submission and ECA supported using the lowest cost tariffs for the flat rate DMO tariff.⁸⁵ They were of the view that selecting the lower network tariff will reduce affordability pressures for standing offer customers, especially given network costs comprise a significant proportion of the DMO.⁸⁶ These stakeholders also considered that this approach best ensures consumers do not pay more than efficient costs and mitigates the risk of over-recovery.⁸⁷ ECA also considered that this approach would incentivise retailers to arrange to have the lower network tariff assigned.⁸⁸

The JEC and ACOSS joint submission did not consider that retailers should necessarily be able to recover network charges in the same manner that they are incurred (that is, 'passed through' in the same form in the fixed and variable components of their retail tariffs). Rather, retailers should develop their tariff pricing to manage their network cost risk. While still

⁸³ Regulations, s. 5: the definition of flexible tariff is a tariff 'other than a demand tariff'.

⁸⁴ SACOSS, [Submission to DMO 8 Draft Determination](#), South Australian Council of Social Service, 9 April 2026, pp. 9–10.

⁸⁵ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 4; JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 7.

⁸⁶ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 4.

⁸⁷ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 7; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 4.

⁸⁸ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 7; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 4.

recovering efficient costs, this should be in line with the fundamental purpose of packaging costs and risks into a choice of products consumers will value.⁸⁹

Seven retailers⁹⁰ and the AEC were opposed to the approach of applying the lower of the flat rate and time of use network cost for the flat rate DMO tariff caps and comparison prices. Their reasoning is set out in the sections that follow.

Impracticality and cost of accelerated replacement of meters

Most retailers raised concerns about the ability to arrange and accelerate smart meter installation above the current rate agreed to under the Legacy Meter Replacement Plans (LMRPs). Retailers argued that the assumption that retailers could gain cost efficiencies by moving customers onto time of use network tariffs would only work if they could install more smart meters, which is unrealistic due to practical and operational impediments.⁹¹

Some retailers submitted there are constraints around labour and equipment availability, network tariff reassignment processes and metering coordinator arrangements. Origin Energy contended that reprioritising installations away from the approved LMRPs is likely to increase failed installations and repeat site visits, extend overall timelines and increase travel times, after-hours or expedited work for technicians. They submitted this would likely result in reduced efficiencies under the LMRPs and increase the costs incurred.⁹² EnergyAustralia also noted that the LMRPs involve installation attempts, not completions as such, because of issues like customer refusal, access difficulties, site defects and remediation requirements. This means that even under the scheduled installations a certain amount cannot be performed.⁹³

ENGIE noted that some distributors have expressed concerns that costs may increase if installations occur faster than planned, which could in turn affect both retailers and consumers.⁹⁴

Retailers risk under-recovery of costs for customers with legacy meters

1st Energy, ENGIE, Origin Energy and Alinta Energy put forward that the practical impediments to accelerating the smart meter installations mean that the efficient costs of supply are potentially underestimated. In their view, the draft determination approach

⁸⁹ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 7.

⁹⁰ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 1–2; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 2–5; Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–5; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–7; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 1–6; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–4.

⁹¹ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3–5; Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–5; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–7; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 4–5.

⁹² Origin Energy, [Submission to DMO 8 draft determination](#), 8 May 2026, pp 1–2.

⁹³ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–5.

⁹⁴ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–7.

allocates network tariff risk to retailers, which has implications for retailers' ability to recover their efficient costs.

Retailers stated that due to the limitations in the ability to install smart meters, a substantial proportion of customers would remain on legacy accumulation meters and would be ineligible for lower cost time of use network tariffs.⁹⁵ These instances would impact retailers that have a significant number of customers on flat rate retail tariffs and the corresponding flat rate network tariffs because they could only recover the lower time of use network cost.

The AEC noted that the under-recovery issues arising from the draft determination approach are unlikely to be confined to DMO standing offer customers because market offers are benchmarked to the DMO, which may impact retailers' costs and margins more broadly.⁹⁶

5.2.2 Alternative approaches

AGL and ENGIE supported exploring a blended network cost for the flat rate DMO prices as presented in the issues paper, such as a customer-weighted approach.⁹⁷ The AEC acknowledged the AER's concerns that flat rate customers on lower time of use network costs would 'miss out' on lower costs if the flat rate network tariff was applied. Accordingly, it considered a blending approach a 'second-best approach' that was preferable to the draft determination approach.⁹⁸ The contention is that a blended network cost approach would have the benefit of recognising that customers on a flat rate retail tariff may have either a flat or time of use network tariff. A blending methodology would automatically result in a transition to the full application of a time of use network tariff in the DMO flat rate retail tariff cap as the installations of smart meters progress through to 2030 and flat rate network tariffs are phased out.⁹⁹

EnergyAustralia, Powershop and the AEC preferred the AER adopt the previous DMOs' approaches of applying the flat rate network tariff to the equivalent flat rate DMO tariff when setting network costs.¹⁰⁰ This would reflect the network costs incurred by retailers for customers who remain on flat rate network tariffs.¹⁰¹

The SCCA stated that embedded network operators faced different cost inputs than retailers and that, due to this, the network cost methodology should include an assessment of embedded networks' cost bases and the impact of the price caps to which they are subject.¹⁰²

⁹⁵ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 1–2.

⁹⁶ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 2–3.

⁹⁷ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 2–5; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–7.

⁹⁸ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 2–4.

⁹⁹ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 6–7.

¹⁰⁰ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–5; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–4; AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 2–4.

¹⁰¹ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–5.

¹⁰² Shopping Centre Council of Australia, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 3.

5.3 Final determination

Our final determination for DMO 8 uses a blend of flat rate and time of use network costs to determine the flat rate DMO tariff caps and comparison prices.

We maintain the same time of use network tariffs for the time of use DMO tariff caps and comparison prices. For the time of use DMO tariff caps, we also maintain the structure of the time of use charging windows.

5.3.1 Flat rate DMO tariff cap and comparison prices

Accounting for customers with legacy meters in DMO 8

Our final determination has better accounted for the proportion of customers with legacy meters over the DMO 8 period, and the costs that retailers will incur.

Retailers provided feedback that an installation of smart meters beyond the LMRPs was not feasible and entailed a cost burden. We acknowledge the LMRPs are based on structured plans developed between metering coordinators, DNSPs and retailers with the objective of achieving an efficient and practical rollout of smart meters over the next 5 years. We also recognise the concern that not all legacy meters can be upgraded within the DMO 8 period. As a result, if the draft determination approach is adopted, we would continue to see customers with legacy meters remaining subject to the higher flat rate network tariff throughout DMO 8. Retailers noted this is an unavoidable cost that cannot be mitigated through any improvements in efficiency or other measures.

We acknowledge ECA and the JEC and ACROSS joint submission support for the draft determination approach of allowing recovery of the lower network tariff, and we agree that this approach would mitigate over-recovery. However, after further analysis, we consider that retailers are unable in practice to arrange for all flat rate customers with legacy meters to be subject to lower network tariffs because it is infeasible to install smart meters at a significantly faster rate than the LMRP. We recognise there are instances of under-recovery where a time of use network tariff applies to the DMO flat rate tariff cap and annual price. We consider that this under-recovery would not reflect the efficient costs to supply electricity to standing offer customers.

We acknowledge JEC and ACROSS's view that network tariffs should not be directly passed through in the DMO and instead retailers should manage network pricing risk. We acknowledge that retailers will decide the composition of their retail plans as part of managing risk.

We note that some retailers recommended that the DMO flat rate retail tariff should allow for the recovery of the corresponding flat rate network tariff to avoid under-recovery in the draft approach.¹⁰³ However, this approach introduces over-recovery because it does not reflect the proportion of flat rate retail customers with smart meters already subject to the lower time of use network tariff. This proportion of flat rate customers increases under the LMRPs if

¹⁰³ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 3; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 4; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 5.

customers choose to remain on their flat rate retail tariff for the 2 years after installation of a smart meter, or if the retailer keeps customers on flat rate retail tariffs after installation.

Adopting a blending approach

Given the issue raised above, our final determination applies a blend of flat rate and time of use network tariffs to better calculate efficient network costs retailers incur for customers on flat rate retail tariffs. When considered across the customer population, this approach is a more accurate reflection of the actual costs incurred by retailers and minimises any under or over-recovery of these costs from customers.

This weighted blend is based on the proportions of flat rate customers on smart meters and legacy meters. This approach provides a more accurate estimate of the total cost associated with network tariffs. It recognises that no single tariff can fully capture the overall costs retailers face for network charges, due to the variety of underlying network tariffs linked to customers on flat rate retail tariffs. It also reflects the link between the type of meter a customer has and the underlying network tariffs their retailer faces.

To derive this blend, we:

- calculate the respective annual fixed and variable costs of the flat rate network tariff and the time of use network tariff at the assumed DMO usage and pattern of supply – the time of use network tariff selected for the blend is the default time of use network tariff listed in the Tariff Structure Statements, excluding Ausgrid where the most common time of use network tariff will be applied, as set out in section 5.3.2 of this final determination
- blend these 2 sets of annual fixed and variable costs into a single set of annual fixed and variable costs by a weighted average, with the weightings reflecting the proportions of flat rate retail customers with legacy and smart meters installed – these proportions were derived from the updated compulsory smart meter information notices (April 2026), in which retailers submitted the number of customers on flat rate and time of use retail tariffs alongside their meter type and current network tariff assignment at 31 March 2026
- convert the annualised fixed and variable network costs into tariff components by dividing the annual fixed cost by 365 days and by dividing the annual cost of the blended usage charges by the assumed annual usage.

We consider it appropriate to blend by the observed proportions of flat rate customers currently with smart meters because it reflects the technological capability of the installed meters. We considered incorporating projections of smart meter rollout into the blend. However, we decided not to because this would introduce additional complexity.

We also considered, but decided not to proceed with, applying the LMRP to deriving blends as recommended by Origin Energy in their submission. Using the LMRPs as a basis for deriving weightings to blend flat rate and time of use network tariffs in the DMO flat rate retail tariff introduces additional layers of complexity:

- The LMRP specifies the rate at which legacy meters are to be replaced from December 2025 onwards. This underestimates the prevalence of flat rate retail customers with smart meters and time of use network tariffs, because it does not specify the extent to which flat rate retail customers already have smart meters installed and are subject to time of use network tariffs prior to December 2025. This means the LMRP does not

accurately reflect the proportions of legacy meters and smart meters among flat rate retail customers, which is required to develop an accurate blend of flat rate and time of use network costs specific to the flat rate DMO tariff cap and comparison price.

- The LMRP does not disaggregate by flat rate and time of use retail tariff. This means the LMRP includes customers that will decide to move away from flat rate retail tariffs (and onto time of use, SSO or non-regulated tariffs). We do not consider this appropriate because these cohorts are subject to separate DMO prices (time of use DMO retail tariff cap, SSO retail tariff cap or the non-regulated comparison price).
- The LMRP does not disaggregate by residential and small business customer, which means that we would need to make assumptions about the smart meter uptake rates for the separate residential and small business customer types and tariffs under the LMRP. This would be challenging and likely to result in errors because historically the customer types have different smart meter uptake rates.

Table 5.1 and Table 5.2 set out the flat rate and time of use network cost weightings for the residential and small business DMO flat rate retail tariff cap and comparison price. We observe that Ausgrid and SA Power Networks have comparatively lower uptake of smart meters among the cohort of customers on flat rate tariffs. These regions have higher proportions of customers on time of use retail tariffs, suggesting that customers in these regions have tended to move to time of use retail tariffs when smart meters are installed.

Table 5.1 Flat rate residential customer proportions for blended network costs

Type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Time of use	29.7%	63.2%	38.4%	45.0%	25.1%
Flat rate	70.3%	36.8%	61.6%	55.0%	74.9%

Table 5.2 Flat rate small business customer proportions for blended network costs

Type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Time of use	22.4%	45.4%	21.6%	40.0%	21.9%
Flat rate	77.6%	54.6%	78.4%	60.0%	78.1%

5.3.2 Time of use network costs

Our final determination maintains the draft determination approach of determining network costs in the time of use DMO tariff cap and comparison price by using the underlying prices and structure of the applicable time of use network tariff. This is the default network tariff in all regions except Ausgrid, where the default network tariff assigned is a demand tariff. For Ausgrid, the most common time of use network tariff is applied.

5.3.3 Summary of network costs

Table 5.3 and Table 5.4 outline the annualised flat rate, time of use and blended network costs.

Table 5.3 Comparison of residential network costs with blend

Tariff	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Flat rate	\$780.53	\$930.50	\$1,326.54	\$874.28	\$992.56
Time of use	\$772.78	\$908.48	\$1,213.29	\$747.99	\$919.90
Blended	\$778.23	\$916.59	\$1,283.03	\$817.46	\$974.34

Table 5.4 Comparison of small business network costs with blend

Tariff	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Flat rate	\$2,102.07	\$1,780.29	\$3,119.33	\$1,724.42	\$2,382.72
Time of use	\$2,013.64	\$1,750.84	\$2,402.02	\$1,480.12	\$2,028.42
Blended	\$2,082.28	\$1,766.94	\$2,964.67	\$1,626.61	\$2,305.03

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 approved network tariffs for 2026–27 compared with those used in DMO 7 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. Although revenue determinations set the revenues DNSPs can recover, the revenue DNSPs ultimately receive over an individual year is determined by the amount of actual energy consumed in that year. To ‘true-up’ these variations in revenue, adjustments are made to allowable revenues for the upcoming financial year to ensure that, over time, a distributor only recovers the revenue it is allowed. 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. A further driver of the price paths was the increasing capital expenditure in our determinations, which among other things supports 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.
- Some specific factors for each region contributed to the network cost aspect of the DMO price in 2026–27:
 - In NSW, the NSW Roadmap cost and transmission costs have increased. However, an increase in forecast energy consumption has partially offset price increases for Ausgrid and Endeavour Energy customers. The recovery of previously under-

recovered revenues for Endeavour Energy customers has contributed to increases, while the return of previously over-recovered revenues for Ausgrid and Essential Energy customers have partially offset increases.

- In SE Queensland, transmission costs have increased and a number of approved cost pass-throughs for extreme weather events are contributing to increased costs. The recovery of previously under-recovered revenues has also contributed to increases.
- In South Australia, our revenue determination also included important expenditure to improve the management of safety risks. New transmission costs, including those related to the Firm Energy Reliability Mechanism 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. The return of previously over-recovered revenues has partially offset increases. For residential customers, there is an overall forecast decrease in residential consumption due to higher levels of consumer energy resources. This is leading to higher price increases for residential customers, relative to small business customers.

We acknowledge SACOSS’s request for a greater breakdown of network costs. However, we have not provided a breakdown because their composition is not an element for consideration within the DMO methodology, which directly passes through the network costs as a whole. However, we note that this information is available in the Statement of Reasons and annual pricing models on the AER website.¹⁰⁴

The actual network costs included in the DMO 8 flat rate price have increased since DMO 7 by 0.2% to 10.6%, depending on region and customer type.

The network costs included in the new separate DMO 8 time of use, SSO and non-regulated prices range from decreases of 18.8% to increases of 9.6%, depending on customer type and region. This is because these prices include recovery of lower time of use network costs compared with the 2025–26 flat rate network tariff used in DMO 7.

Table 5.5 sets out the annual network costs in DMO 8.

Table 5.5 2026–27 network costs, inc. GST

Region	Customer type	Network tariff	2026–27 (\$)
Ausgrid	Residential flat rate	Blend of Residential flat EA010 and Residential Time of use EA025	\$778.23
	Residential time of use	Residential Time of use EA025	\$772.78
	Residential SSO		
	Residential non-regulated tariff		

¹⁰⁴ For example, for SA Power Networks, the [Statement of Reasons - SA Power Networks Pricing Proposal](#) sets out the breakdown of costs for a typical bill and the [SA Power Networks – 2026-27 SCS Pricing Model](#) ('Tariff Schedule' worksheet) set out the breakdown of costs by tariff component. Corresponding documents are available for all other DMO regions.

Default market offer prices 2026–27: Final determination

Region	Customer type	Network tariff	2026–27 (\$)
	Residential controlled load	Controlled load 1 EA030	\$81.48
		Controlled load 2 EA040	\$154.17
	Small business flat rate	Blend of Small business flat EA050 and Small business Time of use EA225	\$2,082.28
	Small business time of use	Small business Time of use EA225	\$2,013.64
	Small business non-regulated tariff		
Endeavour Energy	Residential flat rate	Blend of Residential Flat N70 and Residential Time of use N71	\$916.59
	Residential time of use	Residential Time of use N71	\$908.48
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	Controlled load 1 N50	\$164.29
		Controlled load 2 N54	\$226.28
	Small business flat rate	Blend of General Supply Block N90 and General Supply Time of use N91	\$1,766.94
	Small business time of use	General Supply Time of use N91	\$1,750.84
Small business non-regulated tariff			
Essential Energy	Residential flat rate	Blend of LV Residential Anytime BLNN2AU and LV Residential TOU Sun Soaker BLNRSS2	\$1,283.03
	Residential time of use	LV Residential TOU Sun Soaker BLNRSS2	\$1,213.29
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	LV controlled load 1 BLNC1AU	\$130.83
		LV controlled load 2 BLNC2AU	\$207.75
Small business flat rate	Blend of LV Small Business BLNN1AU and LV Small Business TOU Sun Soaker BLNBSS1	\$2,964.67	

Default market offer prices 2026–27: Final determination

Region	Customer type	Network tariff	2026–27 (\$)
	Small business time of use	LV Small Business TOU Sun Soaker BLNBSS1	\$2,402.02
	Small business non-regulated tariff		
Energex	Residential flat rate	Blend of Residential Flat 8400 and Residential TOU Energy 6900	\$817.46
	Residential time of use	Residential TOU Energy 6900	\$747.99
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	Controlled load 1 (super economy) 9000	\$55.91
		Controlled load 2 (economy) 9100	\$55.91
	Small business flat rate	Blend of Small Business Flat 8500 and Small Business TOU Energy 6800	\$1,626.61
	Small business time of use	Small business TOU Energy 6800	\$1,480.12
	Small business non-regulated tariff		
SA Power Networks	Residential flat rate	Blend of Residential Single Rate RSR and Residential Time of Use RTOU	\$974.34
	Residential time of use	Residential Time of Use RTOU	\$919.90
	Residential SSO		
	Residential non-regulated tariff		
	Residential controlled load	Residential single rate RSR (controlled load)	\$161.77
		Residential TOU controlled load	\$184.20
	Small business flat rate	Blend of Small Business BSR and Small Business Time of Use SBTOU	\$2,305.03
	Small business time of use	Small Business Time of Use SBTOU	\$2,028.43
	Small business non-regulated tariff		

6 Environmental costs

For the DMO 8 final determination, we have decided to retain our existing market-based approach to environmental cost forecasting.

Environmental costs represent between 2% and 3% of the DMO 8 prices. Environmental costs have decreased since DMO 7 across all distribution regions, customer types and tariff structures by between 30% and 35%.

National and state-level environmental schemes require retailers to procure energy from renewable sources.



In the DMO, environmental costs reflect retailers' costs to comply with national and state-level environmental schemes.

The National Renewable Energy Target (RET)



Large-scale Renewable Energy Target (LRET) – schemes to support the development of large renewable energy power stations (e.g. solar and wind farms, hydro generators or biomass plants). Retailers incur costs when they acquire the necessary amount of large-scale generation certificates (LGCs) to promote long-term investments in renewable energy infrastructure.



Small-scale Renewable Energy Scheme (SRES) – schemes to support the installation of small systems on residential and business premises (e.g. rooftop solar panels and batteries). Retailers incur costs when they acquire the necessary amount of small-scale technology certificates (STCs) to support small-scale renewable energy infrastructure.



Jurisdictional-based schemes – policies to incentivise reduced consumption at peak demand times and encourage improved energy efficiency. Retailers fund the associated consumer discounts or rebates. These schemes are specific to NSW and South Australia.

The Regulations require us, when determining a DMO price, to have regard to certain matters including the cost of compliance with Commonwealth and state-level laws, efficient costs, the long-term interests of consumers and the DMO objective.¹⁰⁵

¹⁰⁵ Regulations s. 16(4).

6.1 Draft determination

Our draft determination maintained our existing market-based approach to calculating environmental costs because it reflects efficient costs to supply customers and reflects environmental costs incurred by a retailer. This approach (with updates to new and amended schemes) has been used from DMO 2 to DMO 7.¹⁰⁶

6.2 Stakeholder views

No submissions to our draft determination discussed environmental costs.

6.3 Final determination

Our final determination maintains our previous market-based approach to forecast environmental costs, including costs associated with relevant jurisdictional schemes.

We consider this approach reflects efficient costs to supply customers and comply with Commonwealth and state-level laws and schemes, noting no stakeholders objected to this approach in the draft determination.

6.3.1 Summary of environmental costs

Environmental costs have decreased for all customers in all regions. Decreases are a result of lower LRET and SRES costs faced by retailers. LRET costs have decreased due to significant falls in large-scale generation certificate prices, while SRES costs have fallen as retailers are required to surrender fewer small-scale technology certificates (STCs) than in DMO 7. The SRES is designed with a reduction in the availability of STCs annually until its phase-out in 2030. This measured decrease is part of Australian energy policy, which encourages early adoption of renewable technologies and withdraws government incentives as the solar industry matures and technological costs decrease.¹⁰⁷

Jurisdictional scheme cost reductions in South Australia have contributed to the overall decrease in DMO 8.¹⁰⁸ Environmental cost inputs for 2026–27 are shown in Table 6.1, alongside 2025–26 for comparison.

¹⁰⁶ AER, [Default Market Offer prices Final determination 2025–26](#), Australian Energy Regulator, pp. 49–51, sections 6.1 and 6.3.

¹⁰⁷ CER, [Small-scale Renewable Energy Scheme](#), Clean Energy Regulator; CER, [Small-scale technology certificates](#), Clean Energy Regulator.

¹⁰⁸ 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 \(ESCOSA\)](#).

Table 6.1 Environmental costs for 2025–26 (DMO 7) and 2026–27 (DMO 8) (ex. GST, nominal)

DMO region	2025–26 \$/MWh	2026–27 \$/MWh	Change year-on-year (%)
Ausgrid	\$15.93	\$11.09	-30.4%
Endeavour Energy	\$16.22	\$11.23	-30.8%
Essential Energy	\$15.84	\$11.08	-30.0%
Energex	\$11.92	\$8.08	-32.2%
SA Power Networks	\$16.42	\$10.62	-35.3%

7 Retail costs

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

- maintain the customer-weighted average approach to quantify retail costs to serve and other retail costs
- apply the standing offer customer-weighted average approach to quantify ‘modest’ costs to acquire and retain customers
- maintain the customer-weighted average on actual written-off bad debt expenses and allocate bad debt as a fixed cost component of the DMO
- maintain the customer-weighted average to quantify the smart meter allowance and cost of capital allowance to cover the projected shortfall in the smart meter allowance.

Retail costs represent approximately 7% to 16% of the total DMO price for flat rate residential and small business customers and have changed by between –13% and 0.1% since DMO 7, depending on the DMO region.

The Regulations require us, when determining a DMO price, to have regard to certain matters including the efficient costs of supplying electricity to small customers on standing offers, the types of small customers on standing offers, the long-term interests of consumers and the DMO objective.¹⁰⁹ We are also required to have regard to the modest costs of acquiring and retaining small customers, if relevant to the region.¹¹⁰

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 used actual costs incurred by 24 retailers that sell to approximately 98.4% of residential and 97.5% of small business customers in DMO regions.¹¹¹

For the DMO 8 final determination, we collected updated smart meter installations from the 24 retailers who provided retailer cost data, including the number of customers by meter and tariff type and projected customer numbers. The updated smart meter data reflects the continued rollout of smart meters between 30 June 2025 and 31 March 2026.¹¹²

¹⁰⁹ Regulations s. 16(4).

¹¹⁰ Regulations, s. 16(4)(c)(iv).

¹¹¹ Proportions are based on Q2 2025–26 retail performance data.

¹¹² The DMO 8 draft determination was previously informed by smart meter costs and installations as at 30 June 2025.

7.1 Draft determination

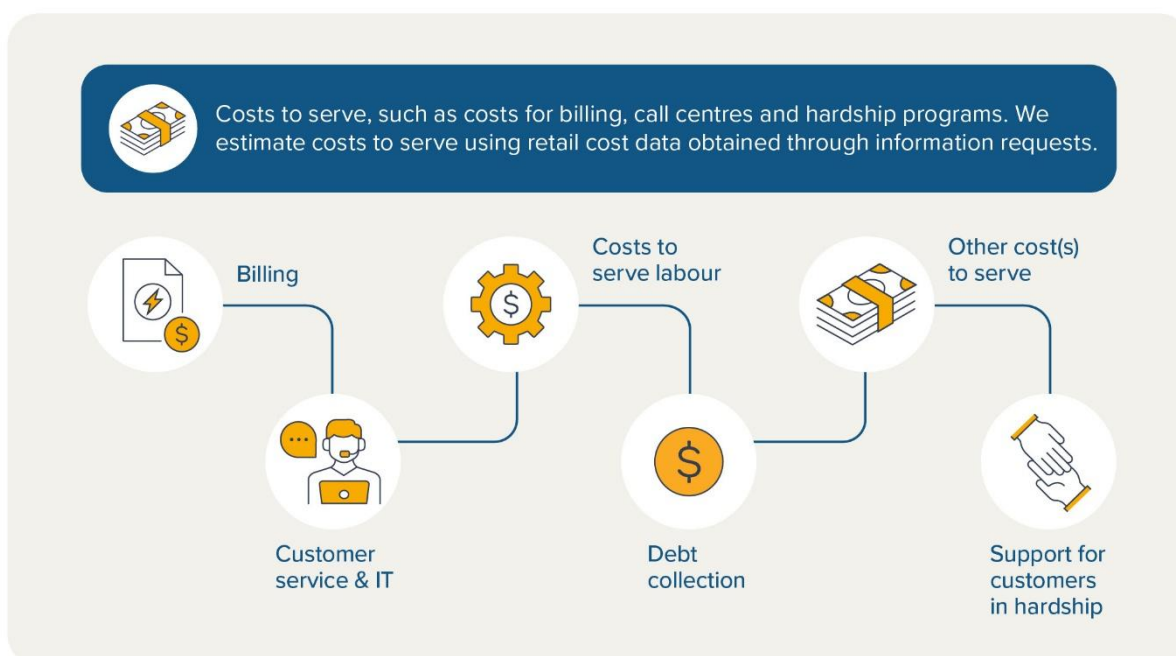
7.1.1 Retail and other costs

Costs to serve and other costs

Our draft determination proposed the customer-weighted average approach to estimate efficient costs to serve and other retail costs. This approach considers each retailer's reported costs to serve, weighted by the respective market share of each retailer.

We considered that this approach represented an estimate of efficient costs of supplying electricity to small customers on standing offers because it reflected the revealed costs reported by retailers (excluding outliers) in a competitive environment. We are required to have regard to efficient costs under the Regulations. This approach is also consistent with previous DMO decisions and the Victorian Default Offer (VDO).

Retailer costs to serve include the following sub-components:



Costs to acquire and retain customers

Our draft determination proposed to apply the standing offer customer-weighted average to estimate 'modest' costs to acquire and retain customers. Modest costs are different to efficient costs and we consider it appropriate to apply a different methodology to determine the level of acquisition and retention costs to include in the DMO. This approach considers each retailer's reported costs to acquire and retain customers, weighted by the respective share of customers on standing offers, rather than total market share, for each retailer.

In contrast to the customer-weighted average approach, this methodology resulted in a reduction in DMO prices for residential and small businesses (ex. GST).¹¹³ This is because

¹¹³ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, p. 78.

the standing offer customer-weighted approach provides greater weight to Tier 1 retailers, which have lower costs and a larger proportion of standing offer customers.

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



7.1.2 Bad debt

Our draft determination proposed to apply the customer-weighted average to quantify actual written-off debt (excluding outliers) and treat bad debt as a fixed cost component of the DMO. This approach is consistent with the ESC’s approach of benchmarking efficient costs.

This represented a change from previous DMO determinations, which relied on provisioned amounts of bad debt. We considered that using actual written-off bad debt protects consumers from the over-recovery of bad debt and prevents the under-recovery of bad debt by retailers.

7.1.3 Smart meter costs

Our draft determination estimated the smart meter allowances and cost of capital using a customer-weighted average (excluding outliers) based on our retail cost information request. Like our approach to costs to serve, other costs and bad debt, we consider that this methodology reflects the revealed costs observed in competitive markets, supporting the recovery of efficient retailer costs.

Smart meter costs will progressively rise due to the ongoing accelerated rollout of smart meters. As we have calculated smart meter costs and installations as at 30 June 2025, we included a smart meter cost of capital allowance to account for the timing difference when costs are calculated and when they will be incurred (during the DMO 8 period). Without this allowance, the smart meter cost allowance would be underestimated for DMO 8.

7.2 Stakeholder views

7.2.1 Costs to serve and other costs

Submissions expressed various views on the approach used to quantify efficient costs to serve and other costs.

The JEC and ACOSS welcomed the methodological changes for DMO 8 and the AER's demonstrated intent to reflect only efficient retail costs in line with the renewed DMO objective.¹¹⁴

Origin Energy and 1st Energy broadly agreed with the AER's continued use of a customer-weighted average approach to estimate efficient costs, including costs to serve.¹¹⁵ Origin Energy considered this approach a suitable indicator for efficient costs since it considers economies of scale and promotes incentives for retailers to meet the cost benchmark.¹¹⁶ While 1st Energy supported the customer-weighted average approach, it noted the underlying costs should be derived from a representative cross-section of retailers, including small and medium retailers, rather than being skewed towards larger retailers.¹¹⁷ ENGIE also considered that customer-weighted estimates are skewed toward Tier 1 retailer cost structures, so it does not reflect the efficient costs that most retailers incur.¹¹⁸

In contrast, ECA argued that retailer costs should be weighted by the number of standing offer customers and recommended that these retailer costs reflect the cost of an efficient retailer, not simply self-reported retailer data.¹¹⁹ It recommended that greater scrutiny be applied to the retail cost dataset so that it does not contain any inefficient costs and that the AER make these costs as transparent as possible.

The AEC and Origin Energy expressed concern with the lack of transparency in how the AER has arrived at its retail operating cost figures.¹²⁰ Specifically, Origin Energy sought clarity on the magnitude in the reduction of retail costs since it could not reconcile its experience of its own costs with the movements in the retail cost benchmark.¹²¹

Hum Energy raised similar concerns with the material reductions to retail operating costs and noted that these reductions do not reflect observed market conditions, including persistent inflationary pressure and elevated compliance and regulatory costs.¹²² Therefore, Hum Energy recommended the methodology and underlying retail cost data be reviewed so that it

¹¹⁴ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 8.

¹¹⁵ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2, Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 8.

¹¹⁶ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 8.

¹¹⁷ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2

¹¹⁸ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 8.

¹¹⁹ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, pp. 4–5.

¹²⁰ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 4; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 8.

¹²¹ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 8.

¹²² Hum Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–4, 8.

reflects observed market conditions.¹²³ Similarly, AGL stressed that retail costs do not capture the RBA’s recent reforms on merchant credit card fees, which commence on 1 October 2026. These reforms remove merchant surcharging and reduce the cost of card transactions for customers, requiring retailers to either absorb or re-allocate card payment costs in their broader pricing and operational structures. Because these reforms also require retailers to update their systems, billing arrangements, customer communications and internal processes to comply with new requirements, it argued that the retail cost benchmark should consider these additional regulatory costs.¹²⁴

7.2.2 Costs to acquire and retain customers

Retailers provided limited feedback on the proposed standing offer customer-weighted average approach to quantify modest acquisition and retention costs.

Origin Energy supported the standing offer customer-weighted average as the most practicable way to set a modest allowance of customer acquisition and retention costs and recommended the AER commit to this approach in future DMO determinations to ensure regulatory certainty and consistency.¹²⁵

In contrast, 1st Energy stressed that a standing offer customer-weighted approach risks understating efficient acquisition costs in a competitive retail market.¹²⁶ It argued that forthcoming National Energy Retail Rules reforms extend standing offer pricing constraints to market customers and warned that setting customer acquisition and retention costs too low could undermine competition and blur the distinction between standing and market offers.¹²⁷

Consumer groups continued to question whether acquisition and retention costs are necessary, efficient or beneficial to standing offer customers, and held the view that these costs should be at or close to zero.¹²⁸ For instance, ECA argued that standing offer customers do not benefit from acquisition and retention activities since they are disengaged from the market, and questioned why enticing customers to switch offers should be considered a benefit to standing offer customers.¹²⁹

The JEC and ACOSS questioned the benefit of acquisition costs since an insignificant proportion of standing offer customers switched to market offers (3.0%). They argued it is unreasonable to assume that retailers meaningfully compete, noting large price dispersion in retail offers between the median and lowest market offer,¹³⁰ and that acquisition activities are

¹²³ Hum Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–4, 8.

¹²⁴ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 8.

¹²⁵ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 8–9.

¹²⁶ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 2–3.

¹²⁷ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 2–3.

¹²⁸ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 5; JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 7–8.

¹²⁹ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 5.

¹³⁰ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 7–8.

an efficient part of competition.¹³¹ They also argued that higher acquisition costs, particularly for smaller retailers, may reflect inefficiency rather than efficient competition. On this basis, the JEC and ACOSS considered there is no justification for any explicit allowance for costs to acquire and retain customers and that if a non-zero amount were adopted, it should be materially lower than the observed standing offer customer-weighted average.¹³²

National Seniors Australia questioned why acquisition and retention costs have grown faster than wholesale and network costs in Ausgrid and SA Power Networks, arguing that most households see little or no benefit despite paying higher retail charges.¹³³ It also noted that should retailers choose to incur advertising and marketing costs, these should be funded from regulated profit margins rather than recovered from standing offer customers.

7.2.3 Bad debt

Several retailers argued that using actual written-off bad debts alone understates bad debt costs and recommended using forward-looking provisioned amounts.¹³⁴

EnergyAustralia emphasised that the key issue is timing since debts are often written off several years after being incurred.¹³⁵ It noted that retailers are required to undertake all available recovery avenues (e.g. payment plans and hardship programs) before a debt is written off, which could take a number of years before a debt first arises. Origin Energy reiterated that it is a common business practice to make provisions for bad debt consistent with Australian Accounting Standards, and that these provisioning practices would create a smoother profile in bad debt.¹³⁶

The AEC and ENGIE noted that bad debt may be underestimated since the data is drawn from a period when households received state and Australian Government bill subsidies and does not reflect worsening cost-of-living conditions.¹³⁷

Powershop argued that the bad debt allowances in the draft determination are based on historical benchmarks and represents a forecast of expected future bad debt, instead of a mechanism for recovering actual bad debt incurred.¹³⁸ Since this shifts any divergence between forecast and realised bad debt onto retailers, it suggested reconciliation mechanisms to better align allowances with actual costs incurred.

¹³¹ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 8.

¹³² JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 7–8.

¹³³ National Seniors Australia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 5–6.

¹³⁴ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 8–9; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 9; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 4–5; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 4–5.

¹³⁵ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 8–9.

¹³⁶ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 9.

¹³⁷ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 4; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 4–5; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 4–5.

¹³⁸ Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 4–5.

7.2.4 Smart meter costs

Submissions generally recognised that smart meter uptake is increasing, but views differed on how costs and installation volumes should be reflected in the DMO.

1st Energy considered the AER's approach to quantifying smart meter allowances should rely on forward-looking, evidence-based projections where appropriate.¹³⁹ ENGIE supported a customer-weighted average to quantify smart meter allowances but did not support the AER's approach of using reported installations as at 30 June 2025 with a cost of capital allowance to cover the projected shortfall.¹⁴⁰ It also contended that historical installation data will not be a reasonable indicator of future smart meter costs once LMRPs begin to significantly accelerate installations from late 2025.¹⁴¹

In contrast, Origin Energy supported continued reliance on historic installation data alongside a working capital allowance until LMRPs are implemented.¹⁴²

ECA argued that smart meter costs should not be included in the retail cost stack without any greater transparency on cost drivers.¹⁴³ National Seniors Australia raised concerns about affordability and equity, arguing that customers are paying a portion of smart meters under the DMO even if they do not have smart meters installed, which may leave disadvantaged or low-flexibility consumers worse off.¹⁴⁴

7.3 Final determination

7.3.1 Costs to serve and other costs

Our final determination maintains the customer-weighted average approach (excluding outliers) to quantify efficient costs to serve and other retail costs. We consider the customer-weighted average approach continues to best reflect the efficient costs because it reflects the revealed costs of retailers operating in a competitive environment. Although not a determinative factor, this approach also maintains regulatory consistency with previous DMO determinations and is consistent with the ESC in determining efficient retail costs for the VDO.

We acknowledge ENGIE's concerns that this approach is skewed towards the costs of Tier 1 retailers, which may not reflect the costs incurred by all retailers. However, our approach considers the revealed costs from a sample of 24 retailers that supply 98.3% of the small customer market across all DMO regions. The customer-weighted average reflects the full range of costs incurred by these retailers in proportion to the number of customers each retailer is supplying in DMO regions. We note that some smaller retailers reported lower costs to serve than Tier 1 retailers, and that it does not necessarily follow that smaller retailers have higher costs to serve than larger retailers. Figure 7.1 sets out the range of

¹³⁹ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2.

¹⁴⁰ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 5–6.

¹⁴¹ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 5–6.

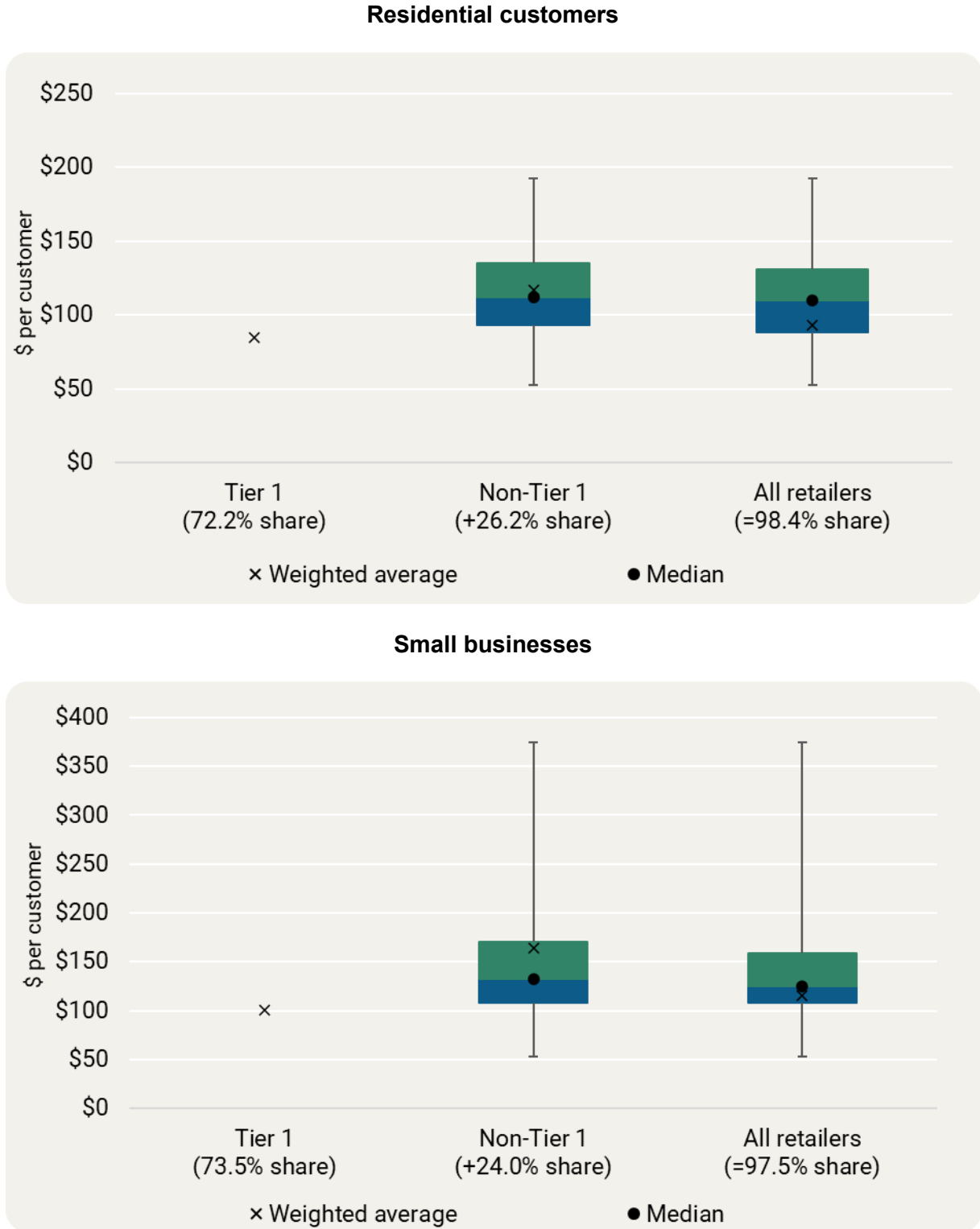
¹⁴² Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 4–6, 9.

¹⁴³ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 5.

¹⁴⁴ National Seniors Australia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 2–3.

costs to serve reported by retailers across DMO regions and shows that some smaller retailers have lower reported costs to serve than the average among Tier 1 retailers.

Figure 7.1 Distribution of costs to serve (\$/customer), by customer type, all DMO regions, ex. GST



Source: AER analysis of retailer cost information.

We also acknowledge ECA's recommendation of applying the standing offer customer-weighted average to quantify efficient costs to serve and other costs. However, we maintain the same view as our draft determination 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 overall customer-weighted average remains an appropriate method for estimating the efficient costs to serve for standing offer customers.

We recognise ECA's concerns about the use of self-reported retailer cost data. As part of our formal retailer cost information request, we have specifically excluded any costs provisioning for legal matters (i.e., fines and penalties), costs associated with retailer offerings outside the scope of the DMO and other costs accounted for elsewhere in the DMO cost stack to avoid risks of double counting. We have also identified significant outliers within the dataset and excluded these outliers from the calculation of the customer-weighted average. This approach provides statistical rigour in ensuring that the retail cost estimates exclude inefficient and one-off costs from our calculations and reflects a consideration of the efficient costs of supplying electricity to small customers on standing offers.¹⁴⁵ Appendix G provides further transparency by breaking down retailer costs and demonstrating the reductions in costs from DMO 7 to DMO 8.

We note Hum Energy's concerns that historical retail costs do not reflect current observed market conditions, including increasing retail operating costs and regulatory compliance costs. We also note AGL's concerns that these retail costs do not consider the impact of the RBA's decision to reduce card transaction costs. While we agree that costs associated with meeting any regulatory obligations should be included in the DMO price, the 2025–26 retail cost information collected from retailers reflects the most up-to-date cost information available. Additional costs from any new or evolving regulatory obligations during the DMO 8 period should be captured in subsequent retail cost information requests and incorporated into the retail cost stack in future DMO determinations.

7.3.2 Costs to acquire and retain customers

Our final determination maintains our approach from the draft determination to apply the standing offer customer-weighted average approach to quantify modest acquisition and retention costs. In making this decision, we had regard to the modest amount of acquisition and retention costs for standing offer customers as required under the Regulations.

This approach considers the Regulations, which require the AER to have regard to the cost of supplying standing offer customers. In addition, this modest allowance is intentionally set differently to an efficient benchmark. It reflects that while all customers benefit from competition, standing offer customers may benefit from some, but not all, acquisition and retention activities, including advertising latest offerings, incentives and product features.

¹⁴⁵ Regulations, s 16(4)(a).

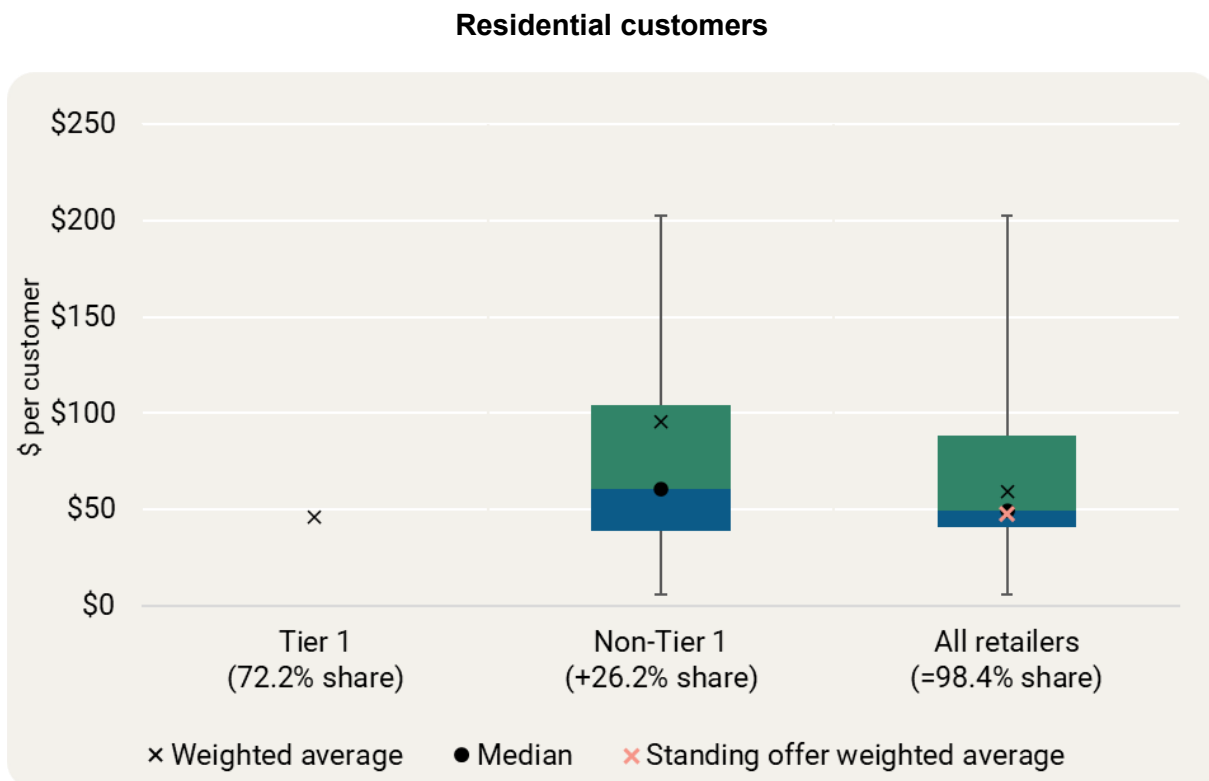
This approach is also consistent with the ESC’s interpretation of ‘modest’, where acquisition and retention costs are intentionally set below cost estimates derived under the customer-weighted average approach.

We note Origin Energy’s support for this approach and share the same considerations that it is the most practicable way to set a modest allowance that, if adopted in future DMO determinations, would ensure regulatory certainty and consistency.

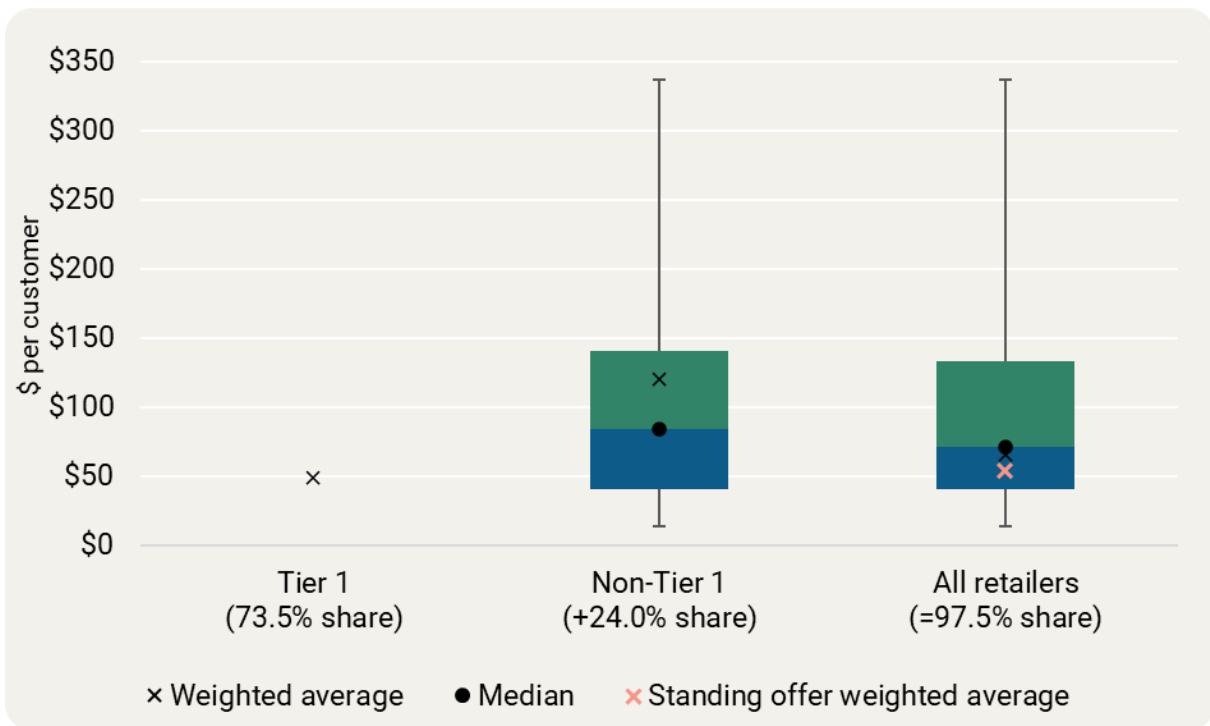
We acknowledge 1st Energy’s concerns that the standing offer weighted average will underestimate the efficient acquisition and retention costs in a competitive environment. While we are required to consider the efficient costs to supply small customers on standing offers, we have a separate requirement to consider modest acquisition and retention allowances. This has led us to a different approach for determining acquisition and retention costs to include in the DMO. Our approach weights retailer acquisition and retention cost data by their respective share of standing offer customers. This means our approach more closely reflects the costs associated with the retailers that supply the greater share of standing offer customers. The majority (86%) of standing offer customers are with Tier 1 retailers, which means their reported acquisition and retention costs are given greater weighting in the calculation of costs under this approach. As Tier 1 retailers typically have lower acquisition and retention costs, this results in a ‘modest’ amount of acquisition and retention costs that is lower than the overall average.

The range of acquisition and retention costs reported by retailers across DMO regions are set out in Figure 7.2.

Figure 7.2 Distribution of costs to acquire and retain customers (\$/customer), by customer type, all DMO regions, ex. GST



Small businesses



Source: AER analysis of retailer cost information.

We also note consumer groups' views that acquisition and retention costs should not be included in the DMO cost stack because they do not directly benefit standing offer customers. However, the Regulations require us to have regard to these costs and we consider a modest level should be included in the DMO price.¹⁴⁶ We consider that without competition driving efficiencies, reported retailer costs that are included in the DMO would be higher. In this way, standing offer customers also benefit from acquisition and retention activities. Using the latest Q2 2025–26 retail performance data, we found that approximately 9% to 11% of standing offer customers have switched to a market offer across the financial year, depending on DMO region.¹⁴⁷ This differs to the previous analysis, where 3% of standing offer customers switched to a market offer at a point in time at the end of the Q1 2025–26 reporting period. Although not conclusive, it does indicate that some acquisition and retention costs encourage disengaged standing offer customers to switch to market offers.

We are also cognisant that some smaller retailers, on average, incur relatively higher acquisition and retention costs relative to their larger incumbents, so the complete removal of these costs would potentially harm the competitive viability of these retailers. Excluding acquisition and retention costs from the DMO cost stack would undermine the stability and continuity of a competitive market, which would not be in the long-term interest of consumers. Therefore, we consider that inclusion of a non-zero modest costs to acquire and retain customers allowance is appropriate because standing offer customers also benefit

¹⁴⁶ [Explanatory Statement](#), Purpose and Operation and Item 43.

¹⁴⁷ AER, [Retail market performance update](#), Quarter 2 2025–26, Australian Energy Regulator, 2 April 2026.

indirectly from competitive pressure that improves retailer efficiency and encourages some customers to move to market offers.

We do not support National Seniors Australia’s proposal that costs to acquire and retain customers should be recovered through the retail margin. As outlined in our draft determination, our Earnings Before Interest, Taxation, Depreciation and Amortisation (EBITDA) margin benchmarking is calculated after costs to acquire and retain customers is deducted from earnings. Efficient margins are only intended to account for systematic risk that sits outside of the DMO cost stack.

7.3.3 Bad debt

Our final determination maintains the customer-weighted average approach to quantify bad debt and we have allocated bad debt as a fixed cost component of the DMO.

While several retailers raised concerns that actual written-off bad debt may understate bad debt,¹⁴⁸ we consider that allowing recovery of actual written-off debt – although involving a degree of lag – remains the most appropriate and robust approach for setting efficient costs.

Bad and doubtful debt provisions are forward-looking estimates. Therefore, they are inherently subjective to retailers’ assessment of expected non-payment. This may result in inconsistent and potentially over-provisioned allowances, which would undermine the objective of setting efficient costs. For instance, we found that the 2023–24 provisioning for bad and doubtful debt figures used in DMO 7 were between \$4 and \$33 (ex. GST) higher than the actual bad debt written off, depending on customer type and DMO region.¹⁴⁹

Allowing recovery of actual bad debt results in a more efficient cost outcome than including provisioned amounts, since applying the actual written-off debt metric reflects realised outcomes after all recovery actions have been exhausted. It prevents under-recovery of bad debt for retailers and protects consumers from the over-recovery of bad debt. That is, using actual written-off bad debt, although lagged, would allow retailers the full recovery of bad debt in future DMO determinations.

The approach is also consistent with other regulators’ approach to bad debt. For instance, in setting the 2025–26 VDO, the ESC incorporated bad debt within retail costs by relying on historical bad and doubtful debt write-offs, rather than forward-looking provisioning measures. Similarly, in its 2025 price determination, the Office of the Tasmanian Economic Regulator used Aurora Energy’s actual bad debt written-off amounts to determine the bad debt allowance.¹⁵⁰

¹⁴⁸ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 8–9; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 9; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 4–5; Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 4–5.

¹⁴⁹ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, p. 81.

¹⁵⁰ OTTER, [2025 Regulated Retail Electricity Pricing Investigation](#), Office of the Tasmanian Economic Regulator, 12 May 2025, p. 38.

7.3.4 Smart meter costs

Our final determination maintains the customer-weighted average approach (excluding outliers) to quantify smart meter costs. However, as flagged in our draft determination, we updated the smart meter counts to reflect the increased uptake of smart meter installations between 30 June 2025 and 31 March 2026.

We acknowledge ECA’s concerns that smart meter costs should not be included in the DMO cost stack if there is no transparency on the drivers of these costs. However, we consider smart meter costs to be a component of the DMO cost stack since retailers incur these costs, particularly within the context of the accelerated rollout of smart meters across DMO regions.

Table 7.1 shows the updated smart meter costs for the DMO 8 final determination. Compared with the draft DMO 8 determination, smart meter costs have increased between approximately \$3.95 and \$6.83 by customer type and DMO region, reflecting the increased uptake of smart meters. Between 30 June 2025 and 31 March 2026, there has been a further 5.5 to 6.2 percentage point increase of smart meters uptake among residential customers and between a 3.3 and 6.0 percentage point increase for small businesses.

Appendix B provides a detailed breakdown of our calculation of smart meter costs, including the cost of capital allowance.

Table 7.1 Average annual smart meter cost per customer, ex. GST

DMO region	Draft DMO 8 determination	Final DMO 8 determination	Change (\$)
Residential customers, flat rate and time of use			
Ausgrid	\$50.41	\$57.18	\$6.76
Endeavour Energy	\$79.29	\$85.46	\$6.17
Essential Energy	\$70.66	\$77.19	\$6.53
Energex	\$59.00	\$65.32	\$6.32
SA Power Networks	\$61.66	\$68.05	\$6.39
Small businesses, flat rate and time of use			
Ausgrid	\$39.69	\$45.76	\$6.07
Endeavour Energy	\$68.70	\$73.02	\$4.32
Essential Energy	\$63.53	\$69.85	\$6.32
Energex	\$61.30	\$65.25	\$3.95
SA Power Networks	\$61.61	\$68.44	\$6.83

Source: AER analysis of retailer cost information.

7.3.5 Summary of retail costs

Table 7.2 and Table 7.3 provide a detailed breakdown of retail cost components for residential customers and small businesses, respectively. Given the retail cost data we have

collected relates to 2024–25, 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.

While our approach for estimating retail costs remains unchanged since the DMO 8 draft determination, the decline in the retail cost component of the DMO is slightly offset by the minor increase in smart meter costs, due to the slight rise in smart meter installations since the draft. Nevertheless, relative to DMO 7, retail costs declined across both customer types and across all DMO regions, with the exception of small businesses in SA Power Networks, for which retail costs remained relatively stable.

Overall, the factors that contributed to this decline include lower reported retail costs from retailers, using actual written-off bad debt reported by retailers and the change in methodology to quantify modest acquisition and retention costs.

The retail costs included in the DMO accommodate retailers selling to 62% of the customers in DMO regions.

Table 7.2 Retail costs, residential customers, flat rate and time of use, ex. GST

Region	Retail and other costs	Smart meter costs	Bad debt costs	Forecast CPI adjustment	Total	Difference to DMO 7 (%)
Ausgrid	\$165.63	\$57.18	\$36.04	\$18.93	\$277.77	-2.2%
Endeavour Energy	\$165.63	\$85.46	\$36.04	\$21.00	\$308.13	-1.6%
Essential Energy	\$165.63	\$77.19	\$36.04	\$20.40	\$299.25	-4.2%
Energex	\$147.17	\$65.32	\$28.95	\$17.66	\$259.10	-13.2%
SA Power Networks	\$164.26	\$68.05	\$47.00	\$20.43	\$299.74	-1.4%

Table 7.3 Retail costs, small businesses, flat rate and time of use, ex. GST

Region	Retail and other costs	Smart meter costs	Bad debt costs	Forecast CPI adjustment	Total	Difference to DMO 7 (%)
Ausgrid	\$215.21	\$45.76	\$72.80	\$24.42	\$358.18	-6.6%
Endeavour Energy	\$215.21	\$73.02	\$72.80	\$26.41	\$387.44	-5.8%
Essential Energy	\$215.21	\$69.85	\$72.80	\$26.18	\$384.04	-7.8%
Energex	\$184.62	\$65.25	\$40.58	\$21.25	\$311.69	-4.9%
SA Power Networks	\$178.93	\$68.44	\$44.86	\$21.38	\$313.61	0.1%

8 Retail margin

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

- maintain the retail margin as a percentage of the total DMO cost base
- apply a uniform 6% retail margin for both residential and small business customers.

Relative to DMO 7, retail margins changed between $-\$13.72$ and $\$1.98$ for flat rate and time of use residential customers, and changed between $-\$389.30$ and $-\$241.42$ for flat rate and time of use small business customers.

The Regulations require us, when determining a DMO price, to have regard to certain matters including the efficient costs of supplying electricity to small customers on standing offers, the types of small customers on standing offers, the long-term interests of consumers and the DMO objective.¹⁵¹

As discussed in chapter 3, we consider efficient retail margins are an essential part of the DMO to ensure consumers are not paying more than they need to while also allowing the retail market to remain competitive and innovative. Ensuring that customers do not pay more than they need is consistent with statements in the Explanatory Statement accompanying the Regulations and the DMO outcomes paper, that any competition allowance (or headroom) should be excluded from the DMO.¹⁵²

8.1 Draft determination

Our draft determination proposed to apply retail margins as a percentage of total DMO costs. We considered setting margins as a percentage of DMO costs would best promote simplicity, transparency and regulatory certainty.¹⁵³

We proposed uniform margins of 6% for residential and small businesses.¹⁵⁴ This was a reduction in small business margins, which were set at 11% in the previous DMO.

In setting uniform margins, we considered that the risks of serving different customer types were appropriately accounted for in the DMO cost stack for each customer type, including bad debt and compliance risk.¹⁵⁵ In addition, we found that small businesses exhibited lower compliance risks, churn and price sensitivity risks, and that competition for selling electricity to small businesses did not diminish since uniform margins were implemented in the VDO.

To quantify the 6% uniform margins, we analysed various data sources, including EBITDA margins collected as part of our retailer cost information request (Figure 8.1). We considered

¹⁵¹ Regulations s. 16(4).

¹⁵² 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.

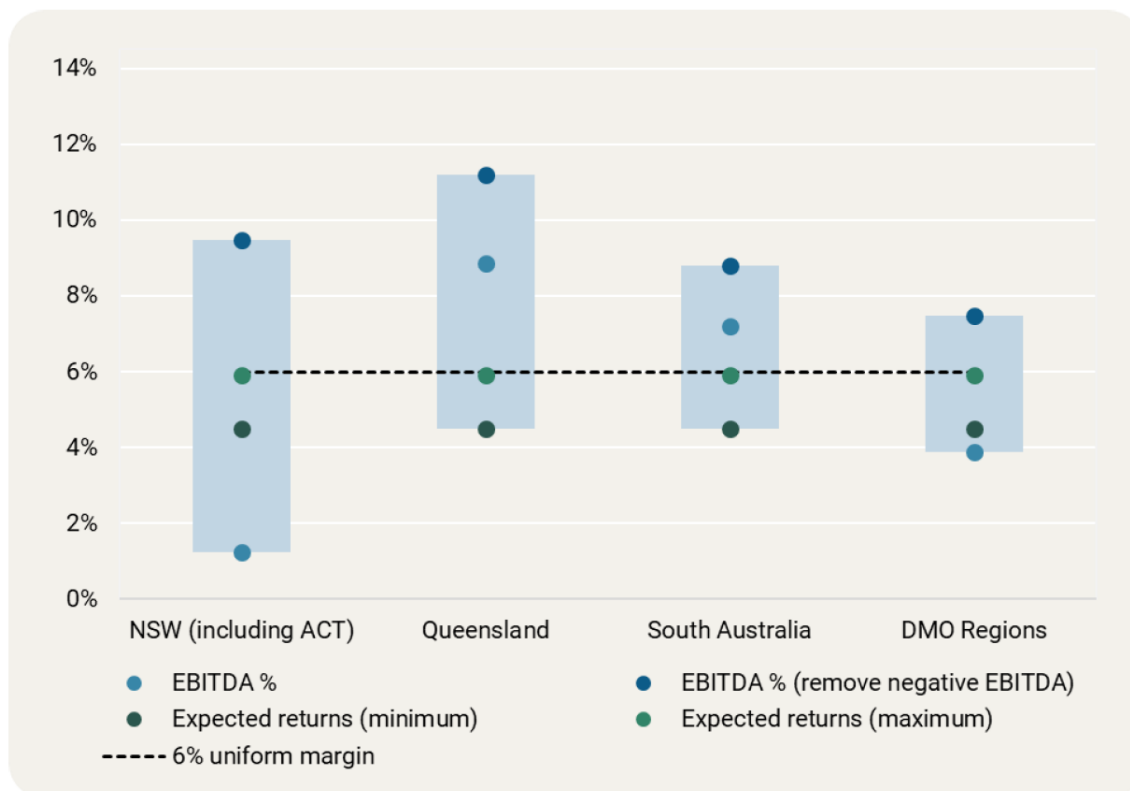
¹⁵³ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, pp. 99–100.

¹⁵⁴ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, p. 85.

¹⁵⁵ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, pp. 90–91.

that the 6% margin contains a degree of conservatism because it sits above the mid-point of EBITDA margins (5.7%) and marginally exceeded the upper bound of Frontier Economics’ estimated range from their expected returns approach (4.5% to 5.9%).¹⁵⁶

Figure 8.1 Range of EBITDA margins for mass market customers, by DMO region



Source: AER analysis of retailer cost information.

8.2 Stakeholder views

8.2.1 Efficient margins

Stakeholders provided a broad range of views in response to our approach in setting the 6% uniform margin in the DMO 8 draft determination.

ECA, the JEC and ACOSS supported uniform margins but advocated for a further reduction to 5% to align with the 2025–26 VDO.¹⁵⁷ ECA argued the conservatism in the AER’s approach is not consistent with the Regulations, which requires the AER to set the DMO based on efficient costs.¹⁵⁸ In its view, a conservative margin would provide retailers with an

¹⁵⁶ Frontier Economics, [Retail electricity price investigation 2024-27](#), 23 November 2023, p. 62.

¹⁵⁷ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, pp. 8–9; JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 10–11.

¹⁵⁸ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, pp. 6–7.

additional buffer above the efficient level. The JEC and ACOSS noted that there is no evidence to suggest that lower margins would lead to significant retail exit.¹⁵⁹

Meanwhile, SACOSS and the South Australian Department for Energy and Mining supported the uniform margin but opposed applying the margin as a percentage on the total cost stack.¹⁶⁰ SACOSS cautioned that a percentage-based approach would amplify price increases as other cost components grow, particularly network costs that allow retailers to achieve greater profits.¹⁶¹

Retailers expressed various views on our approach to uniform retail margins. Origin Energy supported the uniform 6% retail margin in the interests of promoting regulatory certainty.¹⁶² Meanwhile, Alinta Energy, EnergyAustralia and the AEC suggested a gradual reduction to a 6% uniform retail margin could help retailers transition to the new DMO framework.¹⁶³ Alinta Energy noted that a gradual reduction in small business margins from 11% to 6% by DMO 10 would help maintain competition and ensure small businesses continue to benefit from a broad choice of products and ongoing service innovation.¹⁶⁴ Similarly, EnergyAustralia proposed a gradual reduction in small business margins to 8.5% in DMO 8, followed by 6% in DMO 9. EnergyAustralia also argued that compressing a margin by 5% in a single year would trigger a structural repricing of the small business segment and create downward pressure on retailers' capacity to invest in this cohort.¹⁶⁵ The AEC also advocated for a gradual reduction, noting that concurrent methodological changes in the DMO, such as the application of the lowest network tariff in the DMO and the assumption of no load shifting in the Solar Sharer Offer, may increase retailers' exposure to risk.¹⁶⁶

AGL, ENGIE and 1st Energy disagreed with our retail margin decision, arguing that residential and small businesses have inherently different risk profiles.¹⁶⁷ AGL opposed reducing the small business margins, noting that small businesses exhibit more variable and uncertain usage patterns. It also emphasised that small businesses' customer load is more likely to be impacted by economic conditions, which further increases the risk of serving this cohort.¹⁶⁸ ENGIE argued that a reduction in small business margins would only be appropriate if the higher risk of serving small businesses were accounted for in other DMO

¹⁵⁹ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 10–11.

¹⁶⁰ SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, pp. 10–11; South Australian Department for Energy and Mining, [Submission to DMO 8 draft determination](#), 15 April 2026, p. 2.

¹⁶¹ SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, pp. 10–11.

¹⁶² Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 9–10.

¹⁶³ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 2–3; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 11–12; AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 5.

¹⁶⁴ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 2–3.

¹⁶⁵ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 11–12.

¹⁶⁶ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 5.

¹⁶⁷ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 3; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 6; Hum Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 3–4.

¹⁶⁸ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 7.

costs, such as bad debt costs, which it contended was not the case.¹⁶⁹ 1st Energy named variability in usage, credit risk profiles and servicing requirements as the different risk characteristics for small businesses over residential customers.¹⁷⁰

Powershop was also concerned about retail margins, noting that our approach for estimating ranges of EBITDA margins overstated the margins retailers actually achieved and that margin allowances should support investment, innovation and sustaining the long-term interests of consumers.¹⁷¹

The SCCA stated that, unlike retailers, embedded network operators faced numerous structurally different challenges justifying retention of DMO 7 small business retail margins.¹⁷² The SCCA considered embedded network operators' concentrated portfolios could not absorb the small business margin reduction and were exacerbated by the standing offer cap and embedded network owners' site-based operational costs.¹⁷³

8.3 Final determination

Our final determination maintains the retail margin as a percentage of DMO prices and applies a 6% uniform margin to both residential and small business DMO prices.

To ensure that the 6% uniform margins remained appropriate for DMO 8, we analysed retail margins using a range of different approaches, including:

- retail margins inferred from 2024–25 EBITDA data reported by retailers
- retail margins inferred from advertised market offers and the ACCC's customer-weighted average annual prices
- ACCC analysis of actual retail margins based on its December 2024 report
- benchmarking regulatory decisions in different jurisdictions.

We acknowledge the views by ECA, the JEC and ACOSS that the 6% uniform margin may represent an additional buffer above the efficient level and note their recommendation to reduce the retail margin to 5% to align with other regulatory benchmarks. However, we remain of the view that a 6% margin is efficient based on our assessment of margins set out in our draft determination.¹⁷⁴ Our analysis considered 6% efficient because it sat within the range of average EBITDA margins reported by retailers. We also noted that this marginally exceeded the upper bound of Frontier Economics' estimated 4.5% to 5.9% range using their expected returns approach for efficient margins.

¹⁶⁹ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 6.

¹⁷⁰ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3.

¹⁷¹ Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 5.

¹⁷² Shopping Centre Council of Australia, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 4.

¹⁷³ Shopping Centre Council of Australia, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 3.

¹⁷⁴ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, pp. 89–96.

We will assess whether the 6% uniform margin remains appropriate in future DMO determinations based on updated evidence and range of data sources, consistent with the approach adopted in the DMO 8 draft determination.¹⁷⁵

As SACOSS and the South Australian Department for Energy and Mining raised in their submissions, retail margins would increase in dollar terms in response to underlying changes in the DMO cost stack under a percentage-based approach. We maintain that a percentage-based approach over the entire cost stack is appropriate since the margin is intended to compensate retailers for risk, which is related to costs of supplying electricity, including costs retailers incur to use networks. We are not convinced that it is appropriate to exclude margin from network costs as proposed by SACOSS because this would likely understate the level of risk borne by retailers. A percentage margin also scales with costs as they decrease, as well as when they increase.

We acknowledge retailers' and the SCCA's concerns about the impacts of an immediate reduction in small business margins, including proposals to adopt a gradual reduction in margins.¹⁷⁶ However, our analysis in the DMO 8 draft determination indicated that a 6% margin already represents an efficient level of return. We consider that any additional buffer would increase the risks of double counting and overcompensating retailers, which would not be efficient as required by the Regulations.

Setting a glide-path to reduce margins over several years would allow retailers to earn margins above the efficient level of 6%, which would overcompensate retailers for risk. We have had regard to the efficient costs of supplying small customers and we consider such proposals to not reflect efficient margins. Consistent with the legislative intention set out in the Explanatory Statement accompanying the Regulations, any headroom above efficient costs, including the competition allowance, should not be included in the DMO price.¹⁷⁷ The glide-path approach would also result in consumers paying prices that exceed the efficient costs and would not be promoting the long-term interests of consumers.

In setting uniform margins, we consider that small business risk is appropriately captured in the higher retail cost allowances, including costs to serve and actual written-off bad debt.¹⁷⁸ We also maintain the view that relatively lower small business churn risk and lower price sensitivity does not warrant higher small business margins under an efficient DMO pricing framework.

Regarding the SCCA's concerns, we note that the Regulations require us to have regard to the efficient costs (including margin) of supplying electricity in the distribution region to small customers on standing offers.¹⁷⁹ This does not extend to considering the efficient costs (including margin) of supplying electricity to customers in embedded networks, as customers

¹⁷⁵ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, pp. 96–99.

¹⁷⁶ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 2–3; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 11–12; AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 5.

¹⁷⁷ Explanatory Statement accompanying the Regulations, p. 2.

¹⁷⁸ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, pp. 90–92.

¹⁷⁹ Regulations, s16(4)(a).

in embedded networks are excluded from the definition of a customer.¹⁸⁰ As a result, we have not factored this into our DMO 8 determination. We note that the DMO outcomes paper indicates the DMO will be extended to embedded networks from DMO 9 onwards.¹⁸¹ This may provide an opportunity for the AER to have regard to the efficient costs incurred when supplying embedded network customers and reflect these costs in embedded network DMO prices.

8.3.1 Summary of retail margins

The DMO 8 final determination applies a uniform 6% retail margin for residential customers and small businesses. This is summarised in Table 8.1.

Table 8.1 Efficient retail margins, DMO 8 and DMO 7 final determinations, inc. 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 (\$)	\$113.95	\$139.70	\$156.23	\$119.26	\$140.02
Retail margin in DMO 7 (\$)	\$117.88	\$144.68	\$164.45	\$128.55	\$138.03
Difference (\$)	-\$3.93	-\$4.98	-\$8.22	-\$9.29	\$1.98
Residential customers time of use					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 8 (\$)	\$113.60	\$139.19	\$151.78	\$114.83	\$136.54
Retail margin in DMO 7 (\$)	\$117.88	\$144.68	\$164.45	\$128.55	\$138.03
Difference (\$)	-\$4.28	-\$5.50	-\$12.67	-\$13.72	-\$1.49
Small businesses flat rate					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 8 (\$)	\$271.41	\$260.58	\$331.04	\$230.91	\$309.71
Retail margin in DMO 7 (\$)	\$547.52	\$525.28	\$684.43	\$472.33	\$609.51
Difference (\$)	-\$276.12	-\$264.69	-\$353.39	-\$241.42	-\$299.80

¹⁸⁰ Regulations, s6(3)(c).

¹⁸¹ [Review Outcomes: 2025 reforms to the Default Market Offer](#), Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 45.

Default market offer prices 2026–27: Final determination

Customer type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Small businesses time of use					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 8 (\$)	\$267.03	\$259.56	\$295.12	\$221.56	\$292.06
Retail margin in DMO 7 (\$)	\$547.52	\$525.28	\$684.43	\$472.33	\$609.51
Difference (\$)	-\$280.50	-\$265.72	-\$389.30	-\$250.77	-\$317.45

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

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

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

The Regulations require us to determine ‘broadly representative’ annual supply (or annual usage) amounts for residential and small business customers within each DMO region and the timing or pattern of supply.¹⁸²

The AER is required to set a comparison price for each regulated tariff and a comparison price for non-regulated tariffs. The comparison price is an annual price based on what we consider would be a reasonable per-customer annual price for that tariff. In our final determination, we calculated the comparison price for regulated tariffs by applying the annual usage and pattern of supply determinations to the tariff cap for each regulated tariff. The comparison price we set for a non-regulated tariff is equivalent to the price cap on standing offer prices for non-regulated tariffs. Retailers are required to compare their market offers to the comparison prices in customer communications and marketing.¹⁸³

We must also determine DMO tariff caps. In doing so, we must allocate all costs to the daily supply charge, usage charge or a mix of both.¹⁸⁴

9.1 Draft determination

9.1.1 Annual usage amounts

Our draft determination maintained the same annual usage benchmarks as previous determinations for residential and small business customers, including the current controlled load amounts. In making this decision we had regard to relevant data collected from DNSPs

¹⁸² Regulations, s. 16(1)/(1A).

¹⁸³ Regulations, s. 12, 16(1)/(1A); AER and ACCC, [Joint Compliance Bulletin - Changes to the Electricity Retail Code](#), Australian Energy Regulator and Australian Competition and Consumer Commission, April 2026, pp. 3–4.

¹⁸⁴ Regulations, s. 16(1)/(1A).

and retailers in all DMO regions, as well as consumption information published by the ACCC in its July 2025 Inquiry report.¹⁸⁵ We noted the benchmarks are well within range of these datasets, and that the data did not provide evidence of the need to change our methodology for this determination.

9.1.2 Timing and pattern of supply

Our draft determination approach maintained key assumptions from previous determinations, with the removal of the identified controlled load consumption from the AEMO interval meter dataset. We considered this improved the calculations of the timing and pattern of supply.¹⁸⁶

SA Power Networks is the only region with a time of use controlled load tariff. SA Power Networks provided us with 2 years of available interval meter data to inform the draft consumption pattern. The pattern allocated 58% of usage into the evening off-peak window, 42% into the solar sponge and 0% into peak periods.

9.1.3 Apportionment of fixed and variable costs

Our draft determination set out our approach to allocate fixed costs to the daily supply charge and variable costs to the usage charge(s) for all DMO tariff caps, noting it was supported by most stakeholders at the issues paper stage because it allowed for an efficient, accurate and equitable recovery of fixed and variable costs.¹⁸⁷

We acknowledged the feedback from SACOSS to consider any potential inequitable impacts of this approach as higher usage charges could lead to cross-subsidisation from high energy users to low energy users.¹⁸⁸ Consequently, we noted our own concerns that this approach resulted in some daily supply charges in DMO tariff caps that are higher than those in current standing offer tariffs set by retailers.¹⁸⁹

The new requirement to set DMO tariff caps changes how standing offers and tariffs are determined. Previously, annual price DMOs allowed retailers to adjust individual tariff components of standing offer tariffs, provided they did not exceed the annual DMO price. We sought stakeholder feedback on 3 options to shift recovery of some components from the daily supply charge to the usage charge(s):

1. Allocating bad debt to the usage charge
2. Allocating the retail margin to the usage charge
3. A specific manual adjustment, shifting a percentage of the daily supply charge to the usage charge.

¹⁸⁵ ACCC, [Inquiry into the National Electricity Market report – July 2025](#), Australian Competition and Consumer Commission, Appendix E.

¹⁸⁶ ACCC, [Inquiry into the National Electricity Market report – July 2025](#), Australian Competition and Consumer Commission, Appendix E.

¹⁸⁷ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, p. 104.

¹⁸⁸ SACOSS, [Submission to DMO 8 issues paper](#), South Australian Council of Social Service, 1 December 2025, pp. 8–9.

¹⁸⁹ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, p. 108.

9.1.4 Comparison price for non-regulated tariffs

The Regulations require us to calculate an annual comparison price for each customer type for non-regulated tariffs.¹⁹⁰ The comparison price provides price protection for standing offers based on non-regulated tariffs that cannot be readily compared with the flat rate, time of use or SSO DMO tariff caps.

Our draft determination approach set the comparison price for non-regulated tariffs by annualising the time of use DMO tariff cap using the standard annual usage amounts and patterns of supply for residential and small business customers. We considered that setting a single comparison price not based on the flat rate tariff type would result in the most relevant comparison price for consumers. This is because non-regulated tariffs are likely to be more complex than a simple flat rate tariff. Most stakeholder submissions on our issues paper supported this approach because it is the simplest and most transparent, but the need for a comparison price for both flat rate and time of use tariffs was raised, as well as consideration of adopting the most common tariff type.¹⁹¹

9.2 Stakeholder views

9.2.1 Annual usage amounts

Two submissions were received about annual usage amounts.

National Seniors Australia expressed concern that the proposed usage amounts are not representative of all residential customers, specifically for time of use tariffs and annual prices. It noted that if the assumptions differ significantly from the actual consumption pattern or overall usage in a specific peak/off-peak window, the DMO price may underestimate actual costs consumers will pay.¹⁹² Similar feedback was raised by an individual stakeholder, Yousif, that the DMO annual usage benchmarks are an underestimation for larger and higher usage residential consumers and that consideration should be given to using a 7,000 kilowatt hour benchmark.¹⁹³

9.2.2 Timing and pattern of supply

No submissions discussed the timing and pattern of supply.

9.2.3 Apportionment of fixed and variable costs

Most stakeholders supported our draft determination approach to recover fixed costs from the daily supply charge and variable costs from the usage charges.¹⁹⁴

¹⁹⁰ Regulations, s. 16(1)/(1A).

¹⁹¹ AER, [DMO 8 draft determination](#), Australian Energy Regulator, 19 March 2026, p. 104.

¹⁹² National Seniors Australia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–5.

¹⁹³ Yousif, [Submission to DMO 8 Draft Determination](#), 30 April 2026, p. 1.

¹⁹⁴ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 11; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 9; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 9; SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, p. 7.

Stakeholders valued the consistency of the proposed approach, noting it aligned with other jurisdictional retail price regulation methods.¹⁹⁵ EnergyAustralia called the approach fair, efficient and reasonable.¹⁹⁶ Similarly, Origin Energy stated that the approach is objective and will provide transparency.¹⁹⁷ The JEC and ACOSS supported the principled approach of the draft determination, viewing it as the most accurate and equitable approach while providing transparency when comparing retailer offers.¹⁹⁸ Similarly, SACOSS considered the approach the most cost reflective and equitable, aligning with the DMO objective.¹⁹⁹

Noting the higher supply charges, compared with those observed in the current market, most stakeholders did not support any of the draft determination’s proposed options to adjust the allocation of costs between the daily supply and usage charges. ENGIE and Alinta Energy considered the 3 options arbitrary.²⁰⁰ AGL noted that the Regulations result in the draft DMO pricing model not reflecting market-based default and standard market tariffs and structures that have evolved over time.²⁰¹

The South Australian Department for Energy and Mining, EnergyAustralia and AGL acknowledged the difficulties of the issue of high daily supply charges and the importance of taking an approach that addressed the needs of all consumers.²⁰² EnergyAustralia highlighted that no reallocation can be neutral across customer groups – shifting fixed costs to the usage charge reduces daily supply charges for low-usage customers but increases costs for high-usage customers, some of whom are among the most vulnerable.²⁰³

Alinta Energy suggested a more transparent approach, such as the option to allocate bad debt to a variable charge, viewing this as having a more direct and clearer impact on the daily supply charge.²⁰⁴

Compliance Quarter noted it is difficult to define all costs as fixed or variable because some have both fixed and variable costs (e.g., bad debt). However, it preferred the manual option that makes an arbitrary adjustment to shift costs from the daily supply charge to usage

¹⁹⁵ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 9; SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, p. 7; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 9; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3.

¹⁹⁶ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 9.

¹⁹⁷ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 9.

¹⁹⁸ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 11.

¹⁹⁹ SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, p. 7.

²⁰⁰ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 11; SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, p. 7; Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 4; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3.

²⁰¹ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 1–2.

²⁰² South Australian Department for Energy and Mining, [Submission to DMO 8 draft determination](#), 15 April 2026, p. 3; EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 10; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 1–2.

²⁰³ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 10.

²⁰⁴ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 4.

charge(s) because it was the most pragmatic. It also requested the AER set supply and usage charge caps and then allow retailers to set the charges below the caps, which it considered was consistent with the Regulations, protected the long-term interests of consumers and supported a competitive market.²⁰⁵

9.2.4 Comparison price for non-regulated tariffs

No submissions to our draft determination discussed the comparison price for non-regulated tariffs. However, SACOSS requested the AER publish cost stack analysis at the tariff level (daily supply and annual usage charges), which it considered a more useful tool for comparison than annualised prices based on a specific level of consumption.²⁰⁶

9.2.5 Other feedback

Stakeholders noted issues with the calculation of annual controlled load network costs, time of use profiles (used to determine the amount of consumption occurring in each specific time of use window (peak, off-peak, shoulder)) and some of the time of use tariff charging windows.

Origin Energy and 1st Energy identified an error with the calculation of controlled load fixed network costs that were apportioned by usage rather than passed through in full (as other fixed costs are treated in the DMO methodology).²⁰⁷ EnergyAustralia noted a discrepancy between our draft determination annual usage assumptions for some time of use tariffs and the published pattern of supply, while AGL noted Endeavour Energy's time of use tariff did not match the underlying distribution network tariff's weekend timings.²⁰⁸

Feedback was also received about demand tariff usage profiles. EnergyAustralia, ENGIE and AGL all noted concerns that the draft determination did not include assumptions about estimated demand profiles to calculate meaningful comparison prices for demand tariff standing offers.²⁰⁹

9.3 Final determination

9.3.1 Annual usage amounts

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

²⁰⁵ Compliance Quarter, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 4–5, 7.

²⁰⁶ SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, pp. 8–9.

²⁰⁷ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 6–7, 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2.

²⁰⁸ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 9; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 8.

²⁰⁹ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 13. AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 8. ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 6.

We acknowledge the concerns by National Seniors Australia and Yousif that the proposed usage amounts may not be representative of, or appropriate for, all residential consumers.²¹⁰ However, data collected from DNSPs and retailers, and the consumption information published by the ACCC, did not provide sufficient evidence to change the methodology for DMO 8.²¹¹ We consider that consistency and continuity is paramount in the methodology; therefore, we have maintained the current approach.

9.3.2 Timing and pattern of supply

Our final determination maintains the approach to determine the timing and pattern of supply by using updated AEMO interval meter data, which has had identified controlled load consumption data removed, noting no stakeholders opposed this approach. The key assumptions from previous determinations have been maintained, 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
- specify usage at 30-minute intervals.

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 final determination maintains the approach to allocate fixed costs to the daily supply charge and variable costs to the usage charge(s) for all DMO tariff caps, treating bad debt as a fixed cost. We consider this the most suitable approach because it was broadly supported by stakeholders, aligns with the Regulations and is consistent with the tariff setting approaches adopted by the Queensland Competition Authority and the ESC.

We acknowledge the views of EnergyAustralia, the JEC and ACOSS, Origin Energy and SACOSS that this is a fair and equitable approach that will provide transparency and consistency.

However, we continue to share concerns with stakeholders that our approach results in some higher supply charges compared with the current market. Despite these shared concerns, the 3 proposed options in our draft determination did not receive significant support or endorsement, being labelled 'arbitrary'. We note that while Alinta Energy preferred the option to allocate bad debt to a variable charge and Compliance Quarter preferred the manual

²¹⁰ National Seniors Australia, [Submission to DMO 8 draft determination](#), 9 April 2026, pp. 3–5; Yousif, [Submission to DMO 8 Draft Determination](#), 30 April 2026, p. 1.

²¹¹ ACCC, [Inquiry into the National Electricity Market report – July 2025](#), Australian Competition and Consumer Commission, Appendix E.

adjustment option, there was insufficient evidence and a lack of wider support to give these options further consideration.

We acknowledge the South Australian Department for Energy and Mining's concern about the need to find an approach that is fair to all consumers, noting the difficulties in doing so. However, we consider that retailers, in determining market offers, are able to set the balance of the daily supply charge and usage charge different to the DMO tariff caps.

9.3.4 Comparison price for non-regulated tariffs

Due to no stakeholder feedback on our draft determination approach, our final determination uses the annualised time of use DMO tariff and the standard usage amounts for residential and small business customers to determine the comparison price for non-regulated tariffs. We maintain that the simplicity of this approach results in the most relevant price for consumers to use as a basis of comparison. The published final determination cost assessment model includes the cost stack analysis at the tariff level.

9.3.5 Other feedback

Stakeholders noted issues with the calculation of annual controlled load network costs, time of use profiles (used to determine the amount of consumption occurring in each specific time of use window (peak, off-peak, shoulder)) and some of the time of use tariff charging windows. These issues have been addressed in our final determination.

We appreciate stakeholder feedback highlighting methodological inconsistencies and discrepancies that impacted the draft determination annual usage amounts, pattern of supply and the annual comparison prices.

The draft determination approach calculated the weightings of annual energy consumption attributable to each network charging rate (peak, off-peak or shoulder) based on AEMO's Market Settlement and Transfer Solutions (MSATS) interval meter data. It considered extra detail of greater energy consumption in weekdays versus weekends and seasonal differences present in the underlying MSATS data. This is inconsistent with the pattern of supply in the legislative instrument, which assumes the same consumption for each day of the year (that is, no variation in consumption with seasonality or weekday/weekend).

This resulted in inaccuracies in the draft determination annual comparison price for time of use regulated tariffs in 4 distribution regions that have either seasonality and/or weekday/weekend network pricing. The exceptions are Essential Energy, Energex Residential and SA Power Networks Residential because there are no seasonality nor weekday/weekend pricing in these instances.

After examining our approach and stakeholder feedback, and further considering this aspect of the draft determination, our final determination calculation uses the pattern of supply in the legislative instrument to calculate the weightings of annual energy consumption attributable to each network charging rate (peak, off-peak or shoulder).

Updates to how controlled load fixed network costs and DMO tariff caps align with the underlying network tariff have also been addressed.

We have not determined a demand tariff or a specific maximum demand amount in our final determination. There is an implicit maximum demand amount within the pattern of supply,

which will be used to assess compliance with the Regulations. However, we acknowledge that this may not be reflective of the actual maximum customer demand because this is highly dependent on individual customer circumstances, and it is challenging to generalise this to a single value. We encourage retailers to review the ACCC and AER joint compliance bulletin for further information.²¹²

²¹² ACCC and AER, [Joint compliance bulletin - Changes to the Electricity Retail Code](#), Australian Competition and Consumer Commission and Australian Energy Regulator, 20 April 2026.

10 Solar Sharer Offer

For the DMO 8 final 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
- overlay the 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
- not assume any customer load shift when estimating costs incurred during the free usage period in the absence of robust data on SSO consumer behaviour
- reallocate 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 an SSO.²¹³ This opt-in electricity offer is being implemented in DMO regions from 1 July 2026.²¹⁴

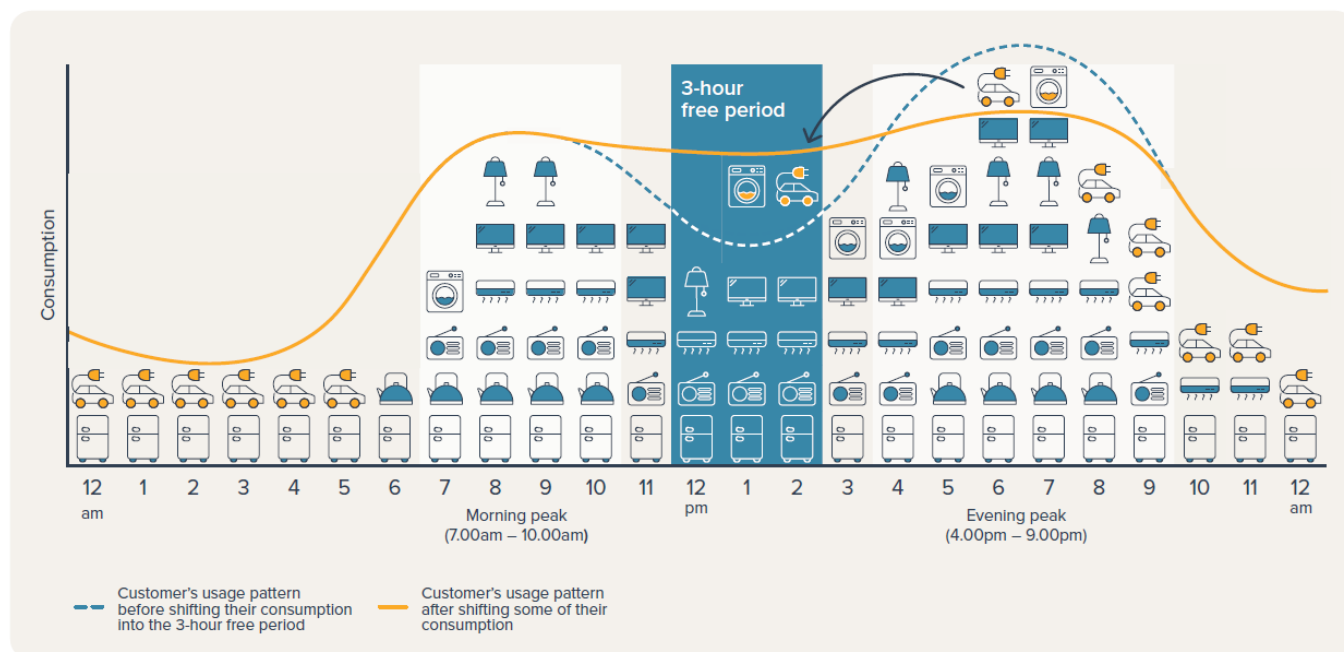
The Australian Government’s objective for the SSO is to enable residential customers with a smart meter to access 3 hours of free electricity in the middle of the day, taking advantage of Australia’s abundant solar generation. Customers who opt in and shift their energy usage into the designated free usage period can reduce their electricity bills. A reasonable use cap of 24 kilowatt hours (kWh) applies to the free usage period, roughly equivalent to a 5-person household shifting its total daily usage into the free hours.

Figure 10.1 illustrates the usage changes that the SSO is designed to encourage to deliver customer bill savings. Shifting consumption from peak usage periods to the free usage period smooths demand and eases grid strain, improving system efficiency and lowering overall system costs.

²¹³ Retailers serving over 1,000 residential customers across all DMO regions will be subject to offering the SSO.

²¹⁴ DCCEEW, [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 Example of the type of load shifting the SSO is intended to encourage



The Regulations require us to:

- determine a 3-hour period each day when energy usage up to 24 kWh is free²¹⁵
- consider periods of high solar generation and low wholesale and network costs in a DMO region, and align (as far as practicable) the free usage period with these periods²¹⁶
- determine a reasonable use tariff cap for usage over 24 kWh during the free usage period.²¹⁷

The Regulations also require us to determine a model annual usage, tariff caps and a comparison price for the SSO.²¹⁸ In determining an SSO price, we are required to have regard to the DMO objective and other mandatory considerations.²¹⁹

The Regulations further provide that, in determining a free usage period, we may have regard to other relevant system and market factors.²²⁰ In determining an SSO price, we must also have regard to any other matter we consider relevant.²²¹ In this respect, we considered 6 design principles for the SSO set out by the Australian Government in the SSO outcomes paper published on 23 January 2026.

²¹⁵ Regulations, Division 3, s.18 (1–2). The Australian Government has set the reasonable use cap at 24 kilowatt hours as per s.18(3)(a) of the Regulations.

²¹⁶ Regulations, Division 3, s.18A(a–b).

²¹⁷ Regulations, s. 18(4).

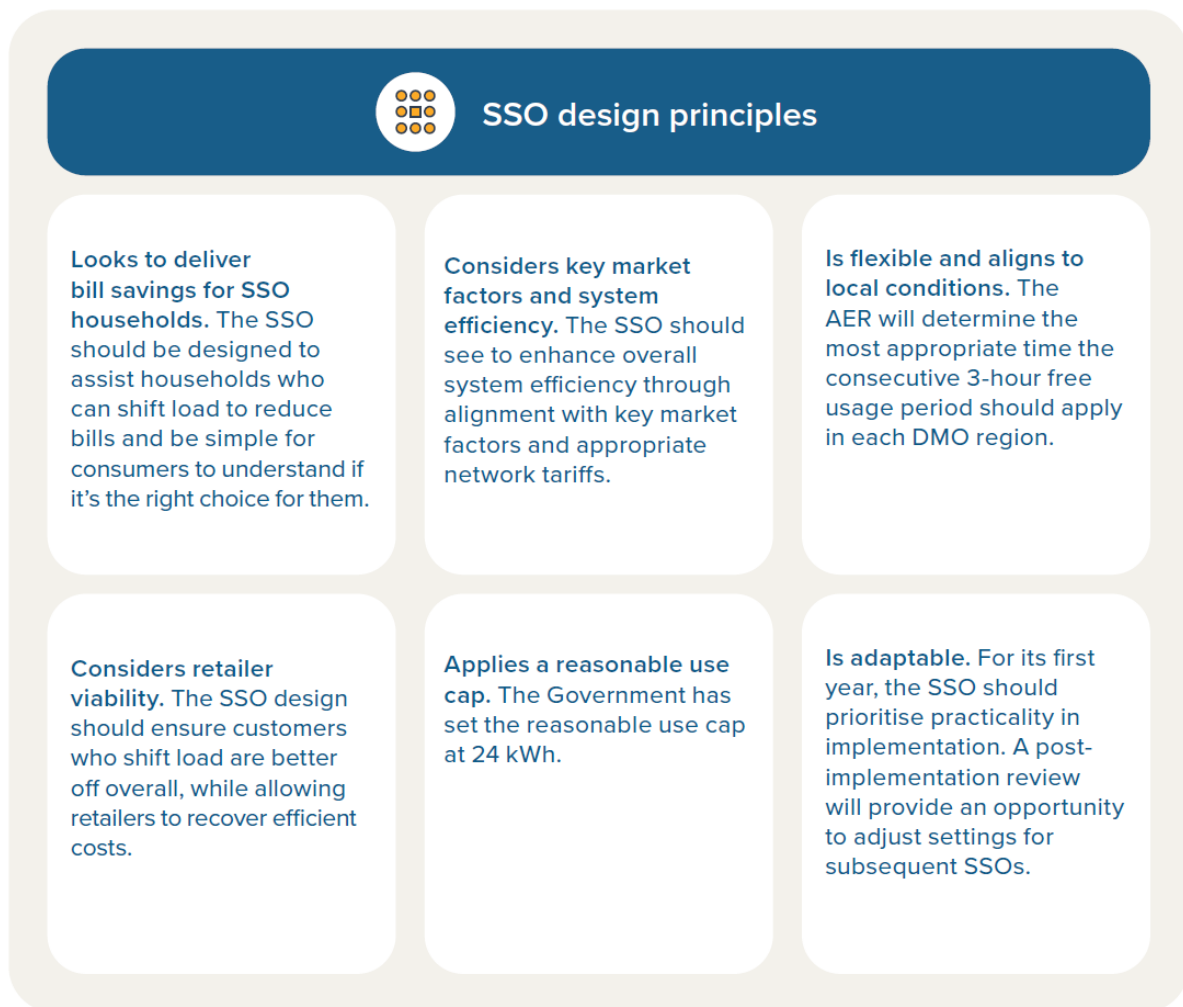
²¹⁸ Regulations, s.16(1A).

²¹⁹ Regulations, s. 16(4).

²²⁰ Regulations, s.18A(c).

²²¹ Regulations, s.18A(c).

Figure 10.2 SSO design principles set by the Australian Government



When considering decisions on the SSO, we have referred to the appropriate design principles that have informed that decision.

10.1 Draft determination

10.1.1 Free usage period

Our draft determination proposed 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 am to 2 pm local time (AEST/AEDT)
- **SE Queensland (Energex):** 11 am to 2 pm local time (AEST)
- **South Australia (SA Power Networks):** 12 pm to 3 pm local time (ACST/ACDT).

We considered that setting the free usage periods at local time year-round would help ensure that the SSO is easier for customers to understand and decide if it is right for them.

When setting the free usage period for each DMO region, 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.²²² We included minimum demand in our analysis, as referenced in the Australian Government’s SSO outcomes paper, given its relevance as an indicator of system vulnerability and surplus generation.²²³ The optimal free usage period was identified as the continuous 3-hour period with the greatest alignment across high solar generation and low wholesale costs, network costs and minimum demand.

For practicality and simplicity, we considered it appropriate to align free usage periods across NSW regions. However, in consideration of the Australian Government’s design principle to align free usage periods with local conditions, we did not propose setting a uniform free usage period across all DMO regions.

10.1.2 Tariff structure

Our draft determination proposed to create the SSO tariff by overlaying the free usage periods onto the corresponding time of use DMO tariffs for each distribution network region. We considered this approach would maintain pricing signals for customers to shift electricity use into the free usage period, particularly from peak periods. In addition, as the time of use DMO tariff already reflects retailers’ efficient costs, basing the SSO on the time of use DMO would help ensure efficient costs to supply SSO customers can be recovered.

Retailers’ recovery of costs incurred in the free usage period

Retailers incur variable costs during the free usage period that cannot be directly recovered at that time. To account for this, the draft determination estimated these costs using the DMO pattern of supply and the respective time of use DMO usage charges and then reallocated the costs across the non-free usage periods on a volume-weighted basis. Under that approach, the estimated costs incurred during the free usage period are recovered through slightly higher usage charges in the non-free usage periods. We did not allocate costs to the daily supply charge to preserve pricing signals and avoid an arbitrary allocation of variable costs.

10.1.3 Reasonable use tariff cap

The Regulations require the AER to determine a reasonable use tariff cap for consumption exceeding 24 kWh during the free usage period.²²⁴ The draft determination proposed setting this cap at the corresponding off-peak or solar soak SSO tariff rate. This approach reflects the efficient costs retailers incur supplying electricity above the reasonable use cap during the free usage period.

10.1.4 Consumer behaviour

Assumptions about SSO customers’ usage impact how we estimate costs incurred by retailers during the free usage period and, accordingly, how the usage charges for non-free usage periods are priced.

²²² Regulations, s.18A(c).

²²³ DCCEEW, [Solar Sharer Offer consultation outcomes paper](#), Department of Climate Change, Energy, the Environment and Water, 23 January 2026, p. 8.

²²⁴ Regulations, s. 18(4).

The draft determination proposed using the DMO pattern of supply without alteration to represent SSO customers' usage profiles. For the first SSO we did not assume any degree of customer load shifting or additional consumption during the free usage period. While the policy intent of the SSO is for customers to shift their usage into the free usage period, we do not currently have enough robust information to make an accurate adjustment to the assumed usage profile. We considered that this approach would best ensure that customers who shift usage into the free usage period are better off, at least compared with if they did not shift their usage while on the time of use DMO.²²⁵

10.2 Stakeholder views

10.2.1 Free usage period

During consultation on the draft determination, most stakeholders did not comment on our proposed approach to setting the free usage periods. The Centre for Smart Power and Energy Research expressed support for our chosen factors, the draft free usage periods and approach to set them in local time. It considered this would benefit customer understanding and help them act on the SSO price signal.²²⁶

The JEC and ACROSS supported the application of free usage periods that vary by region.²²⁷ ECA considered that our draft free usage periods appeared to strike a reasonable balance between simplicity and recognising regional conditions.²²⁸

EnergyAustralia raised a concern about potential ambiguity for customers in Broken Hill, which is in the Essential Energy distribution region (NSW) but observes a South Australian time zone.²²⁹

No stakeholders suggested an alternative approach to setting the free usage periods.

10.2.2 Tariff structure

Origin Energy, ECA, ENGIE and the Centre for Smart Power and Energy Research all supported our proposed approach to base the SSO on the time of use DMO tariffs.²³⁰ However, Origin Energy and ECA both noted the resulting tariff structures were complex and potentially difficult for consumers to understand.²³¹ ECA suggested that we monitor customer understanding to assess whether a simpler version should be developed for future DMOs.²³²

²²⁵ Consistent with design principle 4.

²²⁶ Centre for Smart Power and Energy Research, [Submission to DMO 8 draft determination](#), 1 April 2026, p. 2.

²²⁷ JEC and ACROSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 11.

²²⁸ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8.

²²⁹ EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 13.

²³⁰ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 10; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2; Centre for Smart Power and Energy Research, [Submission to DMO 8 draft determination](#), 1 April 2026, p. 2.

²³¹ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 10; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8.

²³² ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8.

Nectr raised that the draft SSO tariff structures may unintentionally penalise vulnerable groups unable to shift their load, such as renters, people working away from home or households with otherwise inflexible consumption patterns.²³³

Retailers’ recovery of costs incurred in the free usage period

The JEC and ACOSS supported the draft determination’s approach to recover costs incurred in the free usage period through reallocation to the non-free period usage charges rather than to the supply charge.²³⁴ They considered this would maintain price signals and avoid reliance on potentially inaccurate usage assumptions. SACOSS and ECA expressed concern about the magnitude of the resulting peak usage charges. Both consumer groups noted that this would impact the suitability of the SSO for consumers that do not or cannot shift their load.²³⁵ SACOSS considered it important that retailer support be provided to households considering opting in to the SSO and reiterated its position that consumers cannot and do not respond to economic price signals.²³⁶

ENGIE called for the allocation of at least some costs incurred during the free usage period to the supply charge to reduce the risk of under-recovery for retailers.²³⁷

Other retailers made broader points about cost recovery under the SSO framework. 1st Energy considered that costs should be allocated across the electricity supply chain rather than being left for retailers to absorb, while the AEC similarly called for market fees and network and environmental scheme costs to be removed for retailers during the free usage period.²³⁸ Powershop expressed concerns about recovering SSO implementation costs and sought clarity on how they will be allocated and efficiently recovered, particularly for smaller retailers.²³⁹ Nectr considered that the SSO design lacked a clear mechanism for cost recovery, which could create unintended outcomes such as cross subsidisation with non-SSO products.²⁴⁰

10.2.3 Reasonable use tariff cap

Alinta Energy and the AEC called for the reasonable use tariff cap to be raised.²⁴¹ Alinta Energy considered that setting the cap equal to off-peak or solar soak charges would not sufficiently discourage excessive use, which could have system-wide impacts borne by other

²³³ Nectr, [Submission to DMO 8 draft determination](#), 8 April 2026, p. 2.

²³⁴ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 10.

²³⁵ SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, pp. 11–12; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8.

²³⁶ SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, pp. 11–12.

²³⁷ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2.

²³⁸ 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3; AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 5.

²³⁹ Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026, p. 5.

²⁴⁰ Nectr, [Submission to DMO 8 draft determination](#), 8 April 2026, p. 2.

²⁴¹ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3; AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 5.

customers.²⁴² The AEC emphasised the potential for significant losses incurred by retailers from customers meeting the cap.²⁴³ Conversely, ECA noted its general support for the draft position.²⁴⁴

10.2.4 Consumer behaviour

ECA, the JEC and ACOSS all supported our draft position to not assume any load shift when pricing the SSO and agreed that setting an assumption can be more accurately considered when more information on SSO customers' behaviour is available.²⁴⁵ The JEC and ACOSS considered there to be no robust basis currently on which to make a load shift assumption.

Retailers generally opposed this position. The AEC, ENGIE, AGL and Origin Energy all expressed concerns about the resulting risk of cost under-recovery, where retailers may not be able to fully recover their costs for supplying SSO customers who shift a significant amount of usage into the free usage period.²⁴⁶ Origin Energy acknowledged the lack of robust data to forecast consumer behaviour, but called for at least a 'modest' load shift assumption to reduce risk exposure for retailers.²⁴⁷ The AEC and AGL suggested at least an assumption of additional consumption by SSO customers during the free usage period, with the AEC noting that customers who take up the SSO will be more likely to already have load profiles that would benefit from the free period, in part due to mandatory 'better offer' messaging.²⁴⁸ AGL provided insights from its 'Three-for-free' product, showing that battery customers consumed an average of 35% of their daily usage during the free usage period.²⁴⁹

ENGIE acknowledged the lack of reliable data to use for modelling an SSO customer's load profile but emphasised the risk of underestimating consumers' responsiveness to free electricity, particularly given the mandatory communication requirements for retailers to prospective SSO customers. Therefore, ENGIE suggested we find an alternative approach to mitigating under-recovery risks, such as allocation of recoverable costs to the supply charge.²⁵⁰ AGL and the AEC also both considered that the assumption of no load shift effectively presumes the SSO will fail as a policy to encourage customers to shift their

²⁴² Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3.

²⁴³ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 5.

²⁴⁴ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8.

²⁴⁵ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8; JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 10.

²⁴⁶ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 4–5; ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3, 6–7; Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 1, 10.

²⁴⁷ Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026, pp. 1, 10.

²⁴⁸ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3, 6–7; AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 4–5.

²⁴⁹ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 6–7.

²⁵⁰ ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 2.

usage.²⁵¹ 1st Energy similarly expressed concern that the assumption would reduce the incentive to shift load, undermining the policy intent.²⁵²

The AEC also raised a practical consideration if our load shift assumption for future DMOs is based on actual load shifting behaviour of SSO customers. Specifically, the AEC cautioned that SSO customers who shift less load than assumed will either move to other offers more suitable for them or stay and end up worse off. Those low-shifting customers moving off the SSO would then increase the observed load shift for the remaining customers, prompting the AER to increase the load shift assumption further in subsequent DMOs in a year-on-year feedback loop.²⁵³

10.2.5 Other SSO feedback received

Customer communication and implementation

Stakeholders provided feedback on how details on the SSO should be communicated to consumers. ECA emphasised the importance of clear communication and consumer understanding, and called for more sophisticated and targeted information to be provided to consumers.²⁵⁴ The Centre for Smart Power and Energy Research considered that messaging should emphasise the SSO's purpose as a demand shift mechanism supporting Australia's transition to a more flexible energy system and that retailers should be required to clearly communicate the SSO's terms and eligibility requirements.²⁵⁵ Nectr noted that 'better offer' messaging based on historical usage would not capture induced behaviour change or load shift resulting from the SSO.²⁵⁶

Two retailers raised concerns about the timeframe for implementing the SSO by 1 July 2026. Nectr emphasised the burden on small retailers to deliver the required operational change and called for the commencement date to be delayed.²⁵⁷ AGL expressed similar concerns about the resource requirements and implementation cost, as well as the significant risk of consumer confusion. It called for an implementation allowance for the SSO to be included as an additional fixed cost, either separate to or within the existing retail cost allowance.²⁵⁸

Monitoring outcomes

In their submissions, consumer groups emphasised the importance of monitoring the SSO after commencement. SACOSS advocated for comprehensive monitoring by the AER or the ACCC of the SSO's implementation, impacts and outcomes. ECA recommended that the AER monitors outcomes for consumers as well as their understanding of the SSO and

²⁵¹ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, pp. 4–5; AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, pp. 3, 6–7.

²⁵² 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 3.

²⁵³ AEC, [Submission to DMO 8 draft determination](#), Australian Energy Council, 9 April 2026, p. 5.

²⁵⁴ ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8.

²⁵⁵ Centre for Smart Power and Energy Research, [Submission to DMO 8 draft determination](#), 1 April 2026, p. 2.

²⁵⁶ Nectr, [Submission to DMO 8 draft determination](#), 8 April 2026, p. 2.

²⁵⁷ Nectr, [Submission to DMO 8 draft determination](#), 8 April 2026, pp. 2–3.

²⁵⁸ AGL, [Submission to DMO 8 draft determination](#), 10 April 2026, p. 6.

resulting behaviours.²⁵⁹ The JEC and ACOSS recommended we explicitly set out where we intend to refine the SSO design based on improved data, and the criteria against which we will assess the SSO. In their joint submission, they provided a list of data we should collect on the SSO, including consumer behaviour, outcomes, system-level impacts and the types of consumers opting in.²⁶⁰

Controlled load

Three stakeholders also noted concerns about the SSO’s interaction with controlled load, such as potential confusion around whether controlled load usage during the free usage period would still incur a charge. Alinta Energy considered the SSO’s exclusion of controlled load to be inequitable and potentially confusing for customers, leading to complaints and increased administrative burden.²⁶¹ The JEC and ACOSS expressed concern that controlled load customers may be left worse off. They called for the AER to explore options, such as incentives or explicit obligations, to address the risk that retailers might manage controlled load in a way that would serve their own operational objectives rather than maximising benefits for SSO customers, particularly given customers’ limited visibility over controlled load operation.²⁶²

10.3 Final determination

10.3.1 Free usage period

Our final determination maintains the following free usage periods for the SSO tariffs, fixed in local time, year-round (Table 10.1).

Table 10.1 Free usage periods (local time) for each DMO region

DMO region	State	Free usage periods (local time)
Ausgrid	NSW	11 am to 2 pm local time (AEST/AEDT)
Endeavour Energy	NSW	11 am to 2 pm local time (AEST/AEDT)
Essential Energy	NSW	11 am to 2 pm local time (AEST/AEDT)
Energex	Queensland	11 am to 2 pm local time (AEST)
SA Power Networks	South Australia	12 pm to 3 pm local time (ACST/ACDT)

Note: Some areas in the Essential Energy region observe different local times, such as ACST/ACDT.

²⁵⁹ SACOSS, [Submission to DMO 8 draft determination](#), South Australian Council of Social Service, 9 April 2026, p. 12; ECA, [Submission to DMO 8 draft determination](#), Energy Consumers Australia, 10 April 2026, p. 8.

²⁶⁰ JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, pp. 10–12.

²⁶¹ Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026, p. 4.

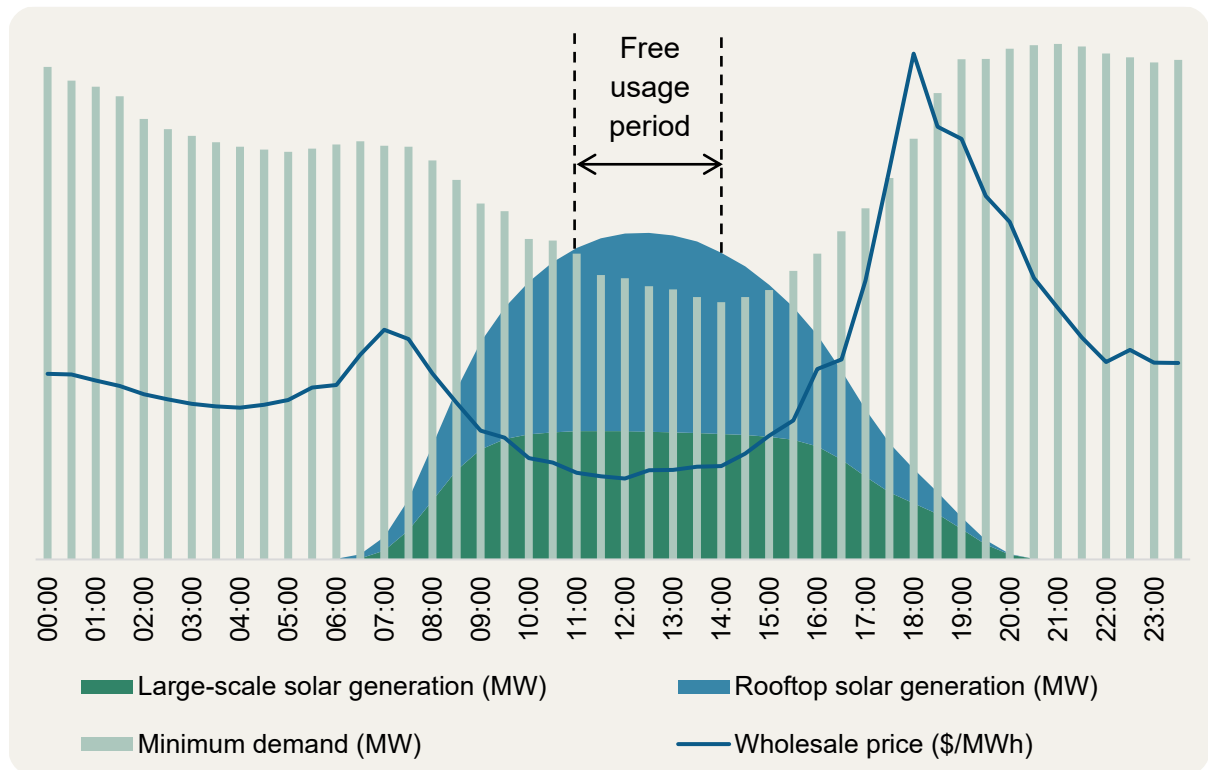
²⁶² JEC and ACOSS, [Submission to DMO 8 draft determination](#), Justice and Equity Centre and Australian Council of Social Service, 13 April 2026, p. 11.

We consider that setting the free usage periods in local time year-round makes the SSO simpler for customers to understand. This provides them with the best opportunity to shift load and understand if it is the right choice for them.

As EnergyAustralia raised, customers in Broken Hill are located within the Essential Energy distribution region (NSW), but they observe the South Australian time zone (ACST/ACDT). We consider the free usage period should begin in accordance with local time for each customer. For example, for customers in Broken Hill, the free usage period will commence at 11 am ACST/ACDT, which is 30 minutes later than it is for other Essential Energy customers who observe AEST/AEDT time. Similarly, for customers located in Queensland but in the Essential Energy distribution region, the free usage period will begin at 11 am AEST. The Legislative Instrument in Appendix C now clarifies that some customers in the Essential Energy distribution region may be subject to different local times.

We maintain our approach from the draft determination to identify the optimal free usage period for each DMO region, as illustrated in Figure 10.3. We used state-level datasets from the past 5 years adjusted to reflect local time and daylight savings. The free usage periods are based on the continuous 3-hour interval that best aligns high rooftop and large-scale solar generation and low network costs, wholesale costs and minimum demand. We aligned each free usage period with periods of low network costs for each DMO region by analysing default time of use network tariffs and other time of use network tariffs with low-cost periods during the middle of the day. Setting the free usage period at times when energy system costs are low means that, where a customer shifts a portion of their load into the free usage period, retailers are expected to face relatively lower costs to recover.

The resulting optimal free usage period is consistent across all NSW regions and Energex. For SA Power Networks, the optimal free usage period occurs later in the day, reflecting the timing of negative minimum demand and low wholesale prices in the early afternoon.

Figure 10.3 Illustrative example of our approach to identifying the free usage periods

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.

10.3.2 Tariff structure

Our final determination maintains our approach to set the SSO tariffs by overlaying the designated free usage periods onto the corresponding distribution network's tariffs used for the time of use DMO. We note the broad stakeholder support for this approach. We acknowledge concerns raised by Origin Energy and ECA that the resulting tariffs' structures may be complex and difficult for consumers to understand. However, we consider that using a time of use tariff structure provides clear price signals to encourage customers to shift usage into the free usage period, particularly from peak periods.

Basing the SSO on the time of use DMO contributes to ensuring retailers can recover their efficient costs to supply SSO customers. The SSO reflects the time of use DMO cost components, including wholesale, network, environmental and retail costs. This means that the total annual bill for the SSO aligns with the time of use DMO.

Retailers' recovery of costs incurred in the free usage period

Our final determination also maintains our approach to the recovery of costs incurred during the free usage period. Under this approach, we estimate the variable costs incurred during the free usage period (wholesale, network and environmental) based on the time of use DMO and pattern of supply. We then reallocate the estimated costs across the non-free usage periods on a volume-weighted basis (Figure 10.4). This results in the usage charges for the non-free usage periods increasing by 1–4 cents per kWh compared with the time of use DMO, depending on the DMO region.

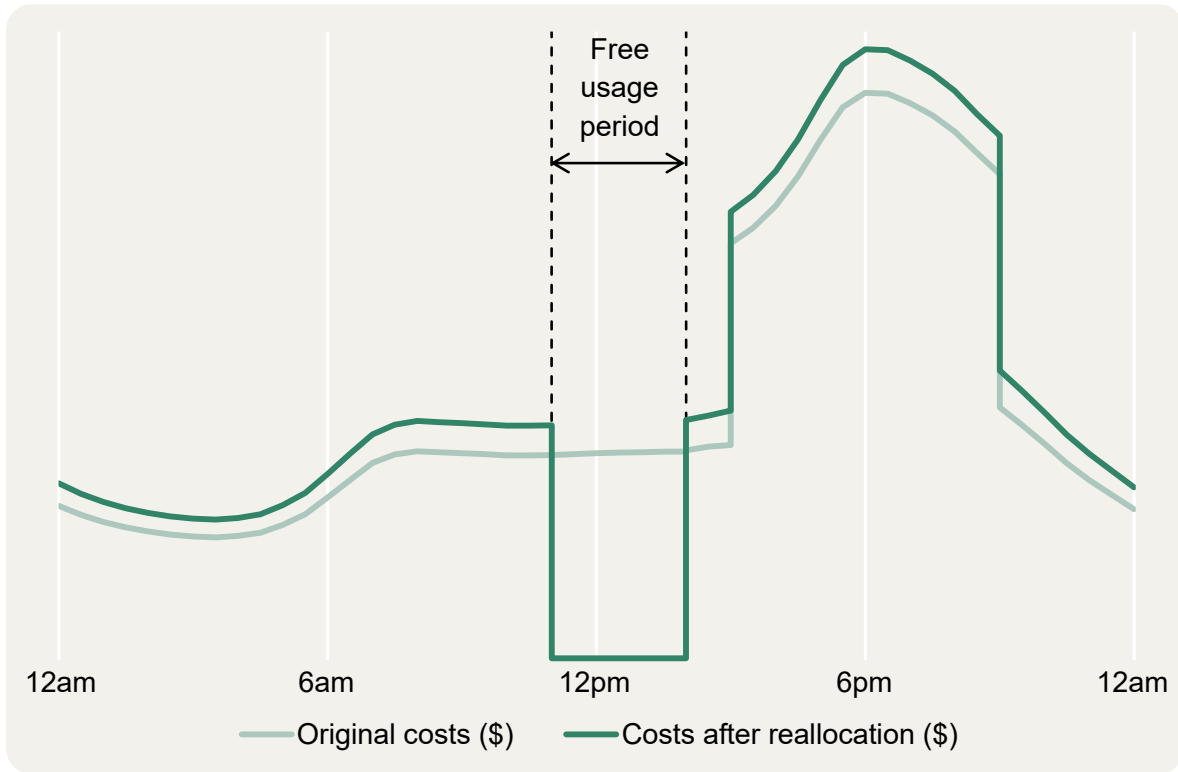
We acknowledge concerns raised by SACOSS and ECA that some households may have limited ability to respond to price signals. As a result, these customers may be disproportionately impacted by high peak usage charges under the SSO. It is important to note that higher usage charges outside the free usage period are necessary to facilitate cost recovery and to encourage customers to shift consumption from peak periods into the free usage period. This highlights the importance of retailer communication to ensure that customers understand whether they could benefit from the SSO. The Regulations require retailers to clearly inform customers that the SSO is best suited to customers who are able to shift their electricity usage to the free usage period, and that failure to do so may result in higher costs.²⁶³ Regardless of the format or channel, retailers are expected to communicate this information to allow customers to make an informed decision about whether to enter into an SSO standing offer, as noted in our joint compliance bulletin with the ACCC.²⁶⁴

ENGIE suggested that a portion of the costs incurred during the free usage period be allocated to the daily supply charge, to mitigate the risk of under-recovery. However, we consider it more appropriate to maintain parity with the time of use DMO daily supply charge and instead facilitate cost recovery for the SSO through the usage charges. Allocating any costs into the daily supply charge would make it more difficult to compare the SSO and time of use offers. Additionally, if daily supply charges absorb a larger portion of cost, the difference between peak and other periods becomes narrower, weakening the incentive for customers to shift their usage into the free usage period. Moreover, it could disadvantage lower usage customers because the daily supply charge comprises a larger proportion of their total bill. Therefore, we have not allocated any costs into the daily supply charge.

²⁶³ Regulations, s. 13

²⁶⁴ ACCC and AER, [Joint compliance bulletin - Changes to the Electricity Retail Code](#), Australian Competition and Consumer Commission and Australian Energy Regulator, 20 April 2026, p. 2.

Figure 10.4 Estimated retailer costs incurred in the free usage period are reallocated to the non-free usage periods



10.3.3 Reasonable use tariff cap

Our final determination maintains our draft determination approach to set the reasonable use tariff cap at the corresponding off-peak or solar soak SSO tariff cap. We consider these usage charges most accurately reflect the efficient costs incurred by retailers for supplying electricity in the free usage period above the 24 kWh reasonable use cap, without introducing unwarranted complexity.

Table 10.2 Reasonable use tariff cap

DMO region	SSO tariff rate	Reasonable use tariff cap
Ausgrid	Off-peak	28 cents per kWh
Endeavour Energy	Solar soak	14 cents per kWh
Essential Energy	Off-peak	28 cents per kWh
Energex	Off-peak	8 cents per kWh
SA Power Networks	Solar soak	20 cents per kWh

We acknowledge feedback from Alinta Energy and the AEC that the reasonable use tariff cap should be higher. However, we do not consider it appropriate to set the reasonable use tariff cap above efficient costs. Using a higher rate, such as the SSO peak charge, would introduce risk for households with particularly high usage by exposing them to high charges in the middle of the day if they unintentionally exceed the reasonable use cap. In addition, the intention of the SSO is to incentivise customers to shift energy consumption from peak

periods into the middle of the day to reduce system-wide demand stress.²⁶⁵ A higher reasonable use tariff cap may reduce that incentive.

10.3.4 Consumer behaviour

Our final determination maintains applying the standard DMO 8 pattern of supply and not assuming any degree of customer load shifting or additional consumption for the first SSO. We consider the DMO pattern of supply to broadly represent residential customers' usage (see chapter 9).

Many retailers raised concerns about assuming no load shifting when pricing the SSO, noting that it could expose retailers to under-recovery risks if customers shift significant energy consumption into the free usage period.

However, at present, there is limited data on how SSO customers are likely to respond to the SSO, meaning that any assumed level of load shifting would be arbitrary and not evidence-based. Anecdotally, retailers have noted that consumer behaviour is difficult to predict with accuracy. For this reason, we do not consider it appropriate to assume any load shifting for the first SSO. As data on SSO customers' behaviour and market response becomes available, we will be in a better position to further assess the implications of assumed consumer behaviour.

Absent of any robust data, the decision not to apply any load shift also better aligns with the Australian Government's design principles to deliver bill savings for SSO customers and to allow retailers to recover efficient costs while ensuring customers who shift load are better off overall.²⁶⁶ We have designed the SSO with the objective that a customer with the same usage profile as the DMO pattern of supply 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. If some degree of load shifting is assumed when pricing the SSO, any customer with the same usage profile as the DMO pattern of supply who does not change their behaviour would pay more on the SSO than they would under the time of use DMO. This could lead to over-recovery of costs. Moreover, customers who shift some usage, but less than the assumed level of load shifting, could still be worse off on the SSO than on the time of use DMO.²⁶⁷

We also consider concerns raised by SACOSS and ECA that the relatively high SSO peak charges introduce risk for consumers who cannot shift usage would be compounded by even higher peak charges if some load shifting was assumed.

10.3.5 Responses to other SSO feedback

Customer communication and implementation

We agree with stakeholder feedback on the importance of clear communication to ensure customers can make an informed decision on whether they would benefit from being on the

²⁶⁵ DCCEEW, [Solar Sharer Offer consultation outcomes paper](#), Department of Climate Change, Energy, the Environment and Water, 23 January 2026, p. 17.

²⁶⁶ In accordance with design principles 1 and 4.

²⁶⁷ Customer outcomes under the SSO are ultimately dependent on their individual usage profiles, which may differ from the DMO pattern of supply.

SSO. The joint compliance bulletin published by the ACCC and AER outlines obligations and expectations for retailers with respect to providing specific SSO information to customers through various channels such as webpages and verbal communications.²⁶⁸ As discussed in section 10.3.2, this includes communicating to customers that:

- the offer is best suited to customers who can shift their usage to the free usage period
- failure to shift usage could result in higher electricity costs
- customers may be charged for use exceeding the reasonable use cap during the free usage period.²⁶⁹

We also acknowledge stakeholder concerns about the timeframe for implementing the SSO by the commencement date. If retailers are experiencing barriers that may prevent full compliance with the Regulations by 1 July 2026, retailers should report compliance issues related to SSO information requirements to the ACCC, and issues with the National Energy Retail Law and Rules (including Better Bills Guideline and Retail Pricing Information Guidelines) to the AER as soon as possible.²⁷⁰

While we acknowledge the need for retailers to upgrade systems to implement the SSO, we do not consider it appropriate to include an explicit allowance for implementation. Building in an implementation allowance would be based on estimation. It could also risk double counting these costs as they will be naturally captured in our retail cost information requests for DMO 9.

Controlled load

Regarding Alinta Energy, the JEC and ACOSS's concerns on the SSO's interaction with controlled load, we note that customers on the SSO may still incur other charges during the free usage period, such as controlled load usage, as the free usage period only applies to variable charges as defined in the Regulations. We note residential controlled load is a regulated tariff, and retailers must ensure that standing offer prices for controlled load comply with the applicable tariff cap set by the AER, including in relation to each fixed and variable charge component.

We consider consumer communication on this matter is critical. As set out in our joint compliance bulletin with the ACCC, it is good practice for retailers to clearly disclose to customers that they may still incur costs for other charges not related to general usage, such as daily supply charges and controlled load usage charges. Retailers are also expected to communicate in a way that ensures prospective customers can easily understand and act on the information provided before opting into the SSO.²⁷¹

²⁶⁸ ACCC and AER, [Joint compliance bulletin - Changes to the Electricity Retail Code](#), Australian Competition and Consumer Commission and Australian Energy Regulator, 20 April 2026, p. 2.

²⁶⁹ ACCC and AER, [Joint compliance bulletin - Changes to the Electricity Retail Code](#), Australian Competition and Consumer Commission and Australian Energy Regulator, 20 April 2026, p. 5.

²⁷⁰ ACCC and AER, [Joint compliance bulletin - Changes to the Electricity Retail Code](#), Australian Competition and Consumer Commission and Australian Energy Regulator, 20 April 2026, p. 7.

²⁷¹ ACCC and AER, [Joint compliance bulletin - Changes to the Electricity Retail Code](#), Australian Competition and Consumer Commission and Australian Energy Regulator, 20 April 2026, pp. 5–7.

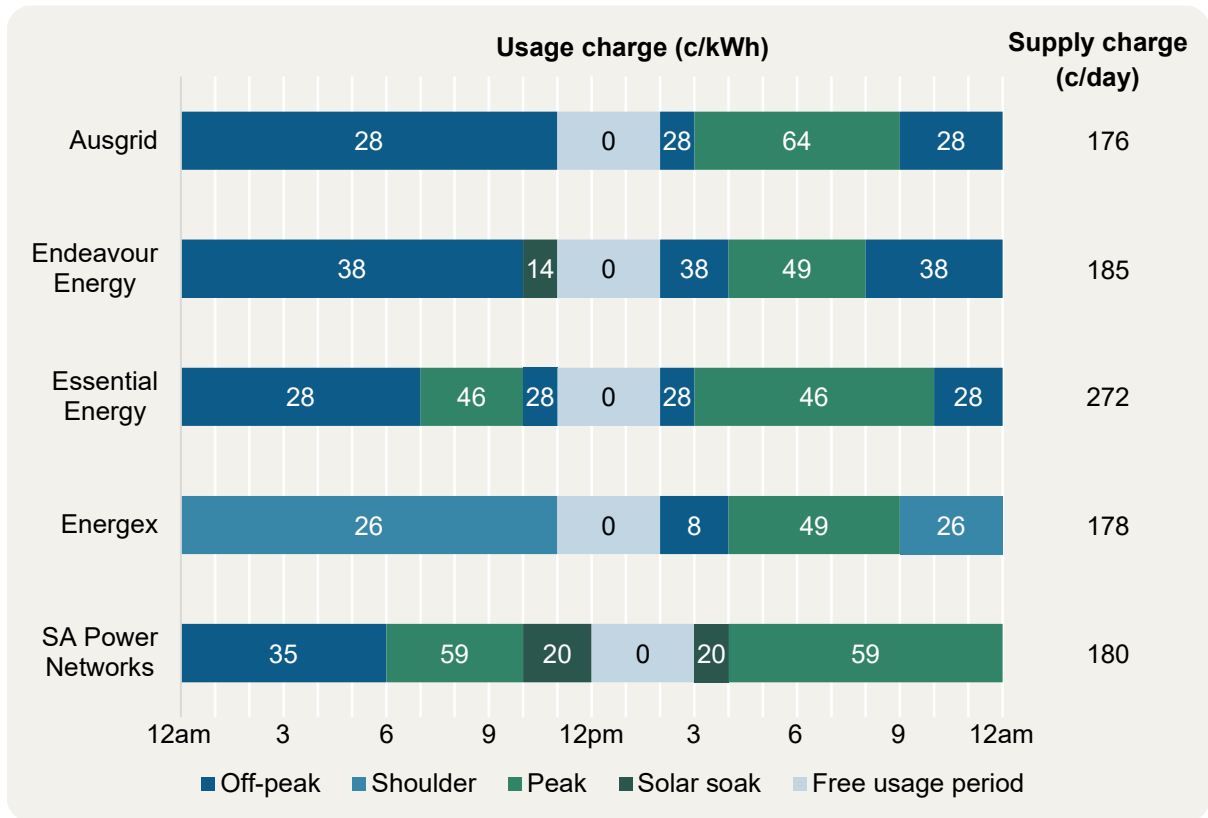
Monitoring outcomes

We agree with stakeholders on the importance of monitoring the market and customer response to the SSO following its commencement. We have prioritised practicality in setting the first SSO tariffs and will consider impacts of the SSO in future determinations based on observed consumer responses, stakeholder feedback and lessons learned. We intend to engage further with stakeholders on this and request specific information from retailers in late 2026 to inform our approach to the next SSO as part of DMO 9. This may involve collecting robust data and information on SSO uptake, consumer behaviour, billing outcomes, feedback on the SSO tariff structure, implementation challenges and system impacts.

10.3.6 Final SSO tariffs

Our final SSO tariffs are shown in Figure 10.5.

Figure 10.5 Final 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). Endeavour Energy has a single year-round peak charge for simplicity, instead of a high season and low season peak charge like the time of use DMO. 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.

11 Appendices

Appendix A – List of submissions to the draft determination

Appendix B – Smart meter costs

Appendix C – DMO Legislative Instrument 2026–2027

Appendix D – DMO 7 to DMO 8 price movements

Appendix E – Year-on-year and methodological changes to annual prices

Appendix F – State-based summaries

Appendix G – Breakdown of retail and other costs

A List of submissions to the draft determination

Following release of the DMO 8 draft determination on 19 March 2026, we invited stakeholder submissions. 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 draft determination](#), 15 April 2026

Industry associations

2. Australian Energy Council, [Submission to DMO 8 draft determination](#), 9 April 2026
3. Shopping Centre Council of Australia, [Submission to DMO 8 draft determination](#), 13 April 2026

Retailers

4. Nectr, [Submission to DMO 8 draft determination](#), 8 April 2026
5. 1st Energy, [Submission to DMO 8 draft determination](#), 9 April 2026
6. Alinta Energy, [Submission to DMO 8 draft determination](#), 9 April 2026
7. ENGIE, [Submission to DMO 8 draft determination](#), 9 April 2026
8. EnergyAustralia, [Submission to DMO 8 draft determination](#), 9 April 2026
9. Local Volts, [Submission to DMO 8 draft determination](#), 10 April 2026
10. AGL, [Submission to DMO 8 draft determination](#), 10 April 2026
11. Powershop, [Submission to DMO 8 draft determination](#), 13 April 2026
12. Hum Energy, [Submission to DMO 8 draft determination](#), 13 April 2026
13. Origin Energy, [Submission to DMO 8 draft determination](#), 13 April 2026; [Additional submission to DMO 8 draft determination](#), 8 May 2026

Consumer groups/representatives

14. South Australian Council of Social Service, [Submission to DMO 8 draft determination](#), 9 April 2026
15. National Seniors Australia, [Submission to DMO 8 draft determination](#), 9 April 2026
16. Energy Consumers Australia, [Submission to DMO 8 draft determination](#), 10 April 2026
17. Justice and Equity Centre and Australian Council of Social Service, [Joint submission to DMO 8 draft determination](#), 13 April 2026

Individuals

18. Yousif, [Submission to DMO 8 draft determination](#), 30 April 2026

Other stakeholders

19. Centre for Smart Power and Energy Research, [Submission to DMO 8 draft determination](#), 1 April 2026
20. Compliance Quarter, [Submission to DMO 8 draft determination](#), 9 April 2026

B Smart meter costs

We requested retailers provide the number of customers on smart meters and accumulation meters for each DMO region and customer type as at 30 June 2025, annual costs incurred for customers with a smart meter as at 30 June 2025 and projected installations for the mid-point of DMO 8 (31 December 2026). For the DMO 8 final determination, we updated these smart meter costs using the number of customers on smart meters and accumulation meters for each DMO region and customer type as at 31 March 2026 and projected installations for the mid-point of DMO 8 (31 December 2026). Tables B.1 and B.2 set out our calculations for estimating smart meter costs per residential and small business customer.

Table B.1 Residential smart meter counts and per-customer costs (ex. GST)

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Total smart meter costs incurred by retailers as at 30 June 2025 (\$)	\$80,086,156	\$77,038,790	\$53,680,820	\$83,214,657	\$47,651,296
Total smart meter customers as at 30 June 2025	675,691	624,824	452,328	768,518	433,087
Average cost incurred per smart meter (\$) as at 30 June 2025 (\$)	\$118.52	\$123.30	\$118.68	\$108.28	\$110.03
ACS metering allowance included in network component (\$)	\$28.54		N/A		
Proportion of customers that do not incur an ACS charge (new connections with smart meters)	8.00%		N/A		
Adjustment to ACS metering allowance reflecting not all customers incur this cost (\$)	-\$2.28		N/A		
Customers with smart meters as at 30 June 2025 (%)	43.2%	63.2%	58.7%	53.5%	55.0%
Customers with smart meters as at 31 March 2026 (%)	49.3%	68.7%	64.6%	59.7%	61.2%
Smart meter cost per customer as at 31 March 2026 (\$)	\$56.18	\$84.73	\$76.63	\$64.68	\$67.34
Additional capital allowance adjustment (see Table B.3)	\$0.99	\$0.73	\$0.56	\$0.64	\$0.71

Table B.2 Small business smart meter counts and per-customer costs (ex. GST)

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Total smart meter costs incurred by retailers as at 30 June 2025 (\$)	\$6,177,235	\$4,796,519	\$4,317,801	\$6,030,259	\$5,017,628
Total smart meter customers as at 30 June 2025	43,957	34,885	30,611	46,361	42,077
Average cost incurred per smart meter (\$) as at 30 June 2025 (\$)	\$140.53	\$137.49	\$141.05	\$130.07	\$119.25
ACS metering allowance included in network component (\$)	\$39.54		N/A		
Proportion of customers that do not incur an ACS charge (new connections with smart meters)	23.52%		N/A		
Adjustment to ACS metering allowance reflecting not all customers incur this cost (\$)	-\$9.30		N/A		
Customers with smart meters as at 30 June 2025 (%)	33.4%	49.2%	44.3%	45.7%	50.6%
Customers with smart meters as at 31 March 2026 (%)	37.8%	52.5%	48.9%	49.4%	56.6%
Smart meter cost per customer as at 31 March 2026 (\$)	\$43.85	\$72.14	\$68.93	\$64.22	\$67.54
Additional capital allowance adjustment (see Table B.3)	\$1.91	\$0.89	\$0.92	\$1.02	\$0.90

Table B.3 Calculation of residential capital allowance adjustment (ex. GST)

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 8, based on actual installations at 31 March 2026	\$56.18	\$84.73	\$76.63	\$64.68	\$67.34
Smart meter allowance based on retailer projected installations at 31 December 2026	\$66.12	\$92.01	\$82.21	\$71.06	\$74.47
Projected shortfall in smart meter allowance at 31 December 2026	\$9.94	\$7.28	\$5.58	\$6.37	\$7.13
Weighted average cost of capital applied in shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance	\$0.99	\$0.73	\$0.56	\$0.64	\$0.71

Table B.4 Calculation of small business capital allowance adjustment (ex. GST)

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 8, based on actual installations at 31 March 2026	\$43.85	\$72.14	\$68.93	\$64.22	\$67.54
Smart meter allowance based on retailer projected installations at 31 December 2026	\$62.92	\$81.01	\$78.16	\$74.46	\$76.54
Projected shortfall in smart meter allowance at 31 December 2026	\$19.07	\$8.88	\$9.24	\$10.24	\$9.00
Weighted average cost of capital applied in shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance	\$1.91	\$0.89	\$0.92	\$1.02	\$0.90

C Legislative instrument



Competition and Consumer (Industry Code— Electricity Retail) (Model Annual Usage, Comparison Prices and Tariff Caps) Determination 2026

The Australian Energy Regulator makes the following determination.

Dated 26 May 2026

Australian Energy Regulator

1 Name

This instrument is the *Competition and Consumer (Industry Code—Electricity Retail) (Model Annual Usage, Comparison Prices and Tariff Caps) Determination 2026*.

2 Commencement

This instrument commences on 1 July 2026.

3 Authority

This instrument is made under subsections 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 subparagraphs 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 paragraph 16(1)(b) and for the regulated tariffs under paragraph 16(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 as referred to paragraph (e) of the definition of regulated tariff in section 5 of the Regulations; and

free usage period means a period determined by the AER under the Solar Sharer Offer 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 paragraph 16(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 subparagraph 16(1)(a)(ii) of the Regulations and for regulated tariffs under subparagraph 16(1A)(a)(ii) of the Regulations; 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 under subsection 18(4) of the Regulations; and

regulated tariff means any of the types of tariffs listed in paragraphs (a)–(g) of the definition of regulated tariffs in section 5 of the Regulations for which the AER determines a comparison price and a tariff cap under subsection 16(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 in paragraph (a) of the definition of regulated tariff in section 5 of the Regulations, that does not vary according to time of day, the amount of supply, the temperature or 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 in paragraph (c) of the definition of regulated tariff in section 5 of the Regulations for residential customers; and

small business flat-rate tariff means a tariff for the supply of electricity referred to in paragraph (b) of the definition of regulated tariff in section 5 of the Regulations, that does not vary according to time of day, the amount of supply, the temperature or 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 in paragraph (d) of the definition of regulated tariff in section 5 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 in paragraph (f) of the definition of regulated tariff in section 5 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 paragraph 16(1A)(c) of the Regulations; and

time of use controlled load tariff means a flexible tariff for supplying electricity to residential customers for use only in specific appliances as referred to in paragraph (e) of the definition of regulated tariff in section 5 of the Regulations; and

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

5 Per-customer annual usage determination

In accordance with subparagraphs 16(1)(a)(i) and 16(1A)(a)(i) of the Regulations, the AER determines the per-customer amount of electricity supplied in specified distribution regions to small customers of the types listed and for regulated and non-regulated tariffs.

Distribution Region	Annual Usage for: – residential flat rate – residential time of use – Solar Sharer Offer – residential non-regulated tariffs	Annual Usage for: – small business flat rate – small business time of use – small business non-regulated tariffs	Annual Usage for: – Residential Controlled Load 1 – Residential Controlled Load 2 – Time of Use Controlled Load (SA Power Networks)	Annual Usage for Residential Controlled Load 1 + 2	
				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	–	–

Note: Figures are based on 365 days per annum in 2026–27 and are expressed in kWh.

6 Timing or pattern of supply determination

In accordance with subparagraphs 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 time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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

Default market offer prices 2026–27: Final determination

(ii) Pattern of supply for comparison prices for small business time of use and small business non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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 time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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

Default market offer prices 2026–27: Final determination

(ii) Pattern of supply for comparison prices for small business time of use and small business non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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 time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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

Default market offer prices 2026–27: Final determination

(ii) Pattern of supply for comparison prices for small business time of use and small business non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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 time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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

Default market offer prices 2026–27: Final determination

(ii) Pattern of supply for comparison prices for small business time of use and small business non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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 time of use, residential Solar Sharer Offer and residential non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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

Default market offer prices 2026–27: Final determination

(ii) Pattern of supply for comparison prices for small business time of use and small business non-regulated tariffs

Time	00:00 -	00:30 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00
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 -	01:00 -	01:30 -	02:00 -	02:30 -	03:00 -	03:30 -	04:00 -	04:30 -	05:00 -	05:30 -	06:00 -	06:30 -	07:00 -	07:30 -	08:00 -	08:30 -	09:00 -	09:30 -	10:00 -	10:30 -	11:00 -	11:30 -	
	00:30	01:00	01:30	02:00	02:30	03:00	03:30	04:00	04:30	05:00	05:30	06:00	06:30	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	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	0.0000	0.1465	0.1465	0.1465	0.1465	0.1465
Time	12:00 -	12:30 -	13:00 -	13:30 -	14:00 -	14:30 -	15:00 -	15:30 -	16:00 -	16:30 -	17:00 -	17:30 -	18:00 -	18:30 -	19:00 -	19:30 -	20:00 -	20:30 -	21:00 -	21:30 -	22:00 -	22:30 -	23:00 -	23:30 -	
	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	21:30	22:00	22:30	23:00	23:30	00:00	
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	0.0000	0.2057

7 Per-customer annual price determination for non-regulated tariff(s)

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

Distribution region	Residential Annual Price (\$)	Small Business Annual Price (\$)
Ausgrid	1,893	4,450
Endeavour Energy	2,320	4,326
Energex	1,914	3,693
Essential Energy	2,530	4,919
SA Power Networks	2,276	4,868

Note: All prices GST-inclusive.

8 Per-customer comparison annual price determination for regulated tariffs

In accordance with paragraph 16(1A)(b) of the Regulations, the AER determines what it considers the reasonable per-customer annual price for supplying electricity under a regulated tariff of that type in specified distribution regions to small customers of that type. These are set out below.

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	CL TOU	
Ausgrid	1,899	4,523	1,893	4,450	403	493	460	–	1,893
Endeavour Energy	2,328	4,343	2,320	4,326	505	537	566	–	2,320
Energex	1,988	3,849	1,914	3,693	312	318	316	–	1,914
Essential Energy	2,604	5,517	2,530	4,919	455	537	531	–	2,530
SA Power Networks	2,334	5,162	2,276	4,868	400	–	–	407	2,276

Note: All prices GST-inclusive.

9 Tariff cap price determination for regulated tariffs

In accordance with paragraph 16(1A)(c) of the Regulations, the AER determines a tariff cap that is a maximum amount of any fixed charge or variable charge or charges that an electricity retailer may charge small customers of that type in that distribution region in the year for supplying electricity under a regulated tariff of that type. These are set out below.

(1) Residential Customers Flat Rate Tariff Cap Price Determination (all prices GST-inclusive)

Distribution Region	Supply charge (c/day)	Usage charge (c/kWh)
Ausgrid	166.2289	33.1372
Endeavour Energy	185.1350	33.7273
Energex	192.0159	27.9744
Essential Energy	272.2168	35.0054
SA Power Networks	180.0512	41.9103

(2) Small Business Customers Flat Rate Tariff Cap Price Determination (all prices GST-inclusive)

Distribution Region	Supply charge (c/day)	Usage charge (c/kWh)
Ausgrid	372.7476	31.6293
Endeavour Energy	244.1375	34.5198 36.0769*
Energex	261.6257	28.9359
Essential Energy	405.6542	40.3667
SA Power Networks	185.5810	44.8449

Note: * The second usage charge in Endeavour Energy applies for all usage in excess of 30,000 kWh per quarter.

(3) Residential Customers Time of Use Tariff Cap (all prices GST-inclusive)

Each distribution region has different start and end times for each time of use period and corresponding usage charge (c/kWh).

Distribution Region	Supply charge (c/day)	Peak Usage charge (c/kWh)	Off-peak Usage charge (c/kWh)	Shoulder Usage charge (c/kWh)	High season peak Usage charge (c/kWh)	Low season peak Usage charge (c/kWh)	Solar Sponge/Soak Usage charge (c/kWh)
Ausgrid	176.4106	60.1966 3pm–9pm (Nov–Mar; Jun–Aug)	24.0387 All other times (incl. all day Apr, May, Sep, Oct)	–	–	–	–
Endeavour Energy	185.1350	–	35.6907 All other times (8pm- 10am and 2pm–4pm working weekday; and 2pm-10am weekends and public holidays)	–	46.5719 4pm–8pm (Nov– Mar; working weekday)	47.1379 4pm–8pm (Apr–Oct; working weekday)	12.3476 10am–2pm; all days
Energex	177.8531	47.7858 4pm–9pm	6.9848 11am–4pm	25.2956 9pm–11am	–	–	–

Default market offer prices 2026–27: Final determination

Distribution Region	Supply charge (c/day)	Peak Usage charge (c/kWh)	Off-peak Usage charge (c/kWh)	Shoulder Usage charge (c/kWh)	High season peak Usage charge (c/kWh)	Low season peak Usage charge (c/kWh)	Solar Sponge/Soak Usage charge (c/kWh)
Essential Energy	272.2168	42.1188 7am–10am; 3pm–10pm	24.1448 All other times (10am– 3pm; 10pm–7am)	–	–	–	–
SA Power Networks	180.0512	56.2218 6am–10am; 4pm–12am	32.5506 12am–6am	–	–	–	17.0431 10am–4pm

Notes: (a) All times are local (accounting for daylight saving and standard time and different time zones within a distribution region). For example, some areas within the Essential Energy region observe different local times.
 (b) Dashes (–) indicate that the time period does not apply for that region.

Default market offer prices 2026–27: Final determination

(4) Small Business Customers Time of Use Tariff Cap (all prices GST-inclusive)

Each distribution region has different start and end times for each time of use period and corresponding usage charge (c/kWh) as set out below.

Distribution Region	Supply charge (c/day)	Peak Usage charge (c/kWh)	Off-peak Usage charge (c/kWh)	Shoulder Usage charge (c/kWh)	High season peak Usage charge (c/kWh)	Low season peak Usage charge (c/kWh)	Solar Sponge/Soak Usage charge (c/kWh)
Ausgrid	387.5833	71.4743 3pm–9pm (Nov–Mar; Jun–Aug) working weekdays	24.8021 All other times (incl. all day Apr, May, Sep, Oct)	–	–	–	–
Endeavour Energy	244.1375	–	38.7908 All other times (8pm–10am and 2pm–4pm working weekday; and 2pm–10am weekends and public holidays)	–	49.6721 4pm–8pm (Nov–Mar; working weekday)	50.2381 4pm–8pm (Apr–Oct; working weekday)	14.1909 10am–2pm; all days
Energex	261.4152	57.3338 5pm–8pm weekdays	8.7353 11am–1pm all days	27.0529 All other times (8pm–11am and 1pm–5pm weekdays; 1pm–11am weekends)	–	–	–

Default market offer prices 2026–27: Final determination

Distribution Region	Supply charge (c/day)	Peak Usage charge (c/kWh)	Off-peak Usage charge (c/kWh)	Shoulder Usage charge (c/kWh)	High season peak Usage charge (c/kWh)	Low season peak Usage charge (c/kWh)	Solar Sponge/Soak Usage charge (c/kWh)
Essential Energy	405.6542	43.6383 7am–10am; 3pm–10pm	27.1316 All other times (10am–3pm; 10pm–7am)	–	–	–	–
SA Power Networks	185.5810	75.9219 5pm–9pm (Nov–Mar)	35.2251 9pm–7am (workdays, Nov–Mar and Apr–Oct); 9pm–5pm (non-workdays, Nov–Mar); all day (non-workdays, Apr–Oct)	43.6220 7am–5pm (workdays, Nov–Mar); 7am–9pm (workdays, Apr–Oct)	–	–	–

Notes: (a) All times are local (accounting for daylight saving and standard time and different time zones within a distribution region). For example, some areas within the Essential Energy region observe different local times.

(b) Dashes (–) indicate that the time period does not apply for that region.

Default market offer prices 2026–27: Final determination

(5) Residential Customers Controlled Load Tariff Cap (all prices GST-inclusive)

Distribution Region	Regulated tariff	Charging components							
		Controlled load 1		Controlled load 2		TOU CL			
		Supply charge (c/day)	Usage charge (c/kWh)	Supply charge (c/day)	Usage charge (c/kWh)	Supply charge (c/day)	Off-peak (11.30pm-6.30am) (c/kWh)	Peak (6.30am-9.30am; 4.30pm-11.30pm) (c/kWh)	Solar Soak (9.30am-4.30pm) (c/kWh)
Ausgrid	Controlled Load 1	4.7312	19.3094	-	-	-	-	-	-
	Controlled Load 2	-	-	8.8784	23.0050	-	-	-	-
	Controlled Load 1 and 2	4.7312	19.3094	8.8784	23.0050	-	-	-	-
Endeavour Energy	Controlled Load 1	13.8929	20.6438	-	-	-	-	-	-
	Controlled Load 2	-	-	13.8929	22.0861	-	-	-	-
	Controlled Load 1 and 2	13.8929	20.6438	13.8929	22.0861	-	-	-	-
Energex	Controlled Load 1	-	16.4323	-	-	-	-	-	-
	Controlled Load 2	-	-	-	16.7451	-	-	-	-
	Controlled Load 1 and 2	-	16.4323	-	16.7451	-	-	-	-
Essential Energy	Controlled Load 1	15.6605	19.8887	-	-	-	-	-	-
	Controlled Load 2	-	-	15.6605	23.9799	-	-	-	-
	Controlled Load 1 and 2	15.6605	19.8887	15.6605	23.9799	-	-	-	-
SA Power Networks	Controlled Load 1	-	22.2497	-	-	-	-	-	-
	Time of Use Controlled Load	-	-	-	-	-	28.7378	42.1569	13.9475

Notes: (a) All times are local (accounting for daylight saving and standard time and different time zones within a distribution region). For example, some areas within the Essential Energy region observe different local times.

(b) Dashes (–) indicate that the charging component does not apply for that region.

Default market offer prices 2026–27: Final determination

(6) Solar Sharer Offer Regulated Tariff for Residential Customers (all prices GST-inclusive)

Each distribution region has different start and end times for each time of use period and corresponding usage charge (c/kWh) as set out below.

Distribution Region	Supply charge (c/day)	Peak Usage charge (c/kWh)	Off-peak Usage charge (c/kWh)	Shoulder Usage charge (c/kWh)	Solar Sponge/Soak Usage charge (c/kWh)	Free usage period
Ausgrid	176.4106	63.7177 3pm–9pm (Nov–Mar; Jun–Aug)	27.5597 2pm–11am (Apr, May, Sep, Oct); 2pm–3pm and 9pm–11am (Nov–Mar; Jun–Aug)	–	–	11am–2pm (Jan–Dec)
Endeavour Energy	185.1350	48.7482 4pm–8pm (working weekday)	37.5300 2pm–4pm and 8pm–10am (working weekday); 2pm–10am (weekends and public holidays)	–	14.1869 10am–11am (all days)	11am–2pm (all days)
Energex	177.8531	48.9020 4pm–9pm	8.1011 2pm–4pm	26.4119 9pm–11am	–	11am–2pm
Essential Energy	272.2168	45.5698 7am–10am; 3pm–10pm	27.5958 10am–11am; 2pm–3pm; 10pm–7am	–	–	11am–2pm
SA Power Networks	180.0512	58.8420 6am–10am; 4pm–12am	35.1708 12am–6am	–	19.6632 10am–12pm; 3pm–4pm	12pm–3pm

Notes: (a) All times are local (accounting for daylight saving and standard time and different time zones within a distribution region). For example, some areas within the Essential Energy region observe different local times.

(b) Dashes (–) indicate that the time period does not apply for that region.

(c) Any electricity usage above 24 kWh during the free usage period will be subject to the reasonable use tariff cap as per section 11 of this legislative instrument.

10 Free Usage Period for SSO regulated tariffs

In accordance with subsection 18(1) of the Regulations, the AER determines a free usage period as part of the tariff structure of an SSO regulated tariff in a distribution region.

Distribution region	Free usage period
Ausgrid	11am–2pm
Endeavour Energy	11am–2pm
Energex	11am–2pm
Essential Energy	11am–2pm
SA Power Networks	12pm–3pm

Notes: All times are local (accounting for daylight saving and standard time and different time zones within a distribution region). For example, some areas within the Essential Energy region observe different local times.

11 Reasonable Use Tariff Cap for SSO regulated tariffs

In accordance with subsection 18(4) of the Regulations, the AER must determine a reasonable use tariff cap for the excess electricity.

Distribution region	Reasonable use tariff cap (c/kWh) (all prices GST-inclusive)
Ausgrid	27.5597
Endeavour Energy	14.1869
Energex	8.1011
Essential Energy	27.5958
SA Power Networks	19.6632

D 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:

- Environmental cost components in the DMO 8 final determination are calculated using predominately the same methodology as DMO 7, so the changes directly reflect year-on-year movement.
- Flat rate network costs use a blend of flat rate and time of use network tariffs.
- 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 cover 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.
- Changes to the wholesale cost component reflect both year-on-year movement and the impact of the methodological adjustments such as adopting the 50th percentile wholesale energy cost (WEC) estimate and applying a volatility allowance.

Figure D.1 Residential flat rate percentage change from DMO 7 (nominal)

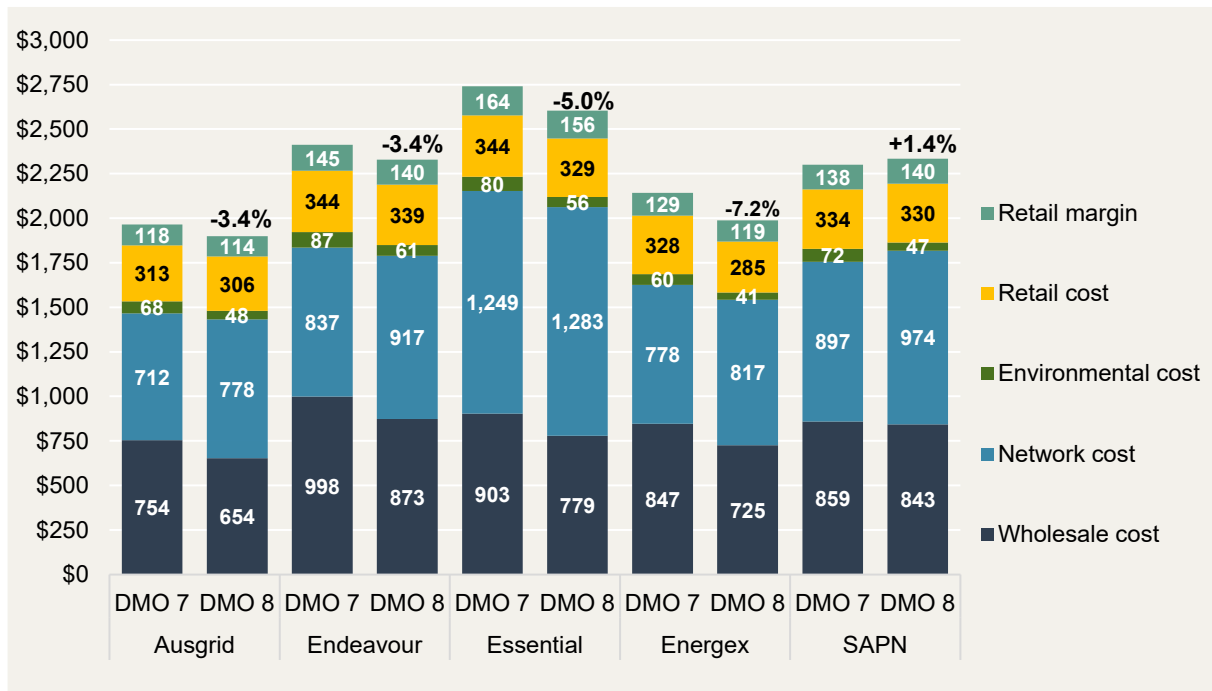
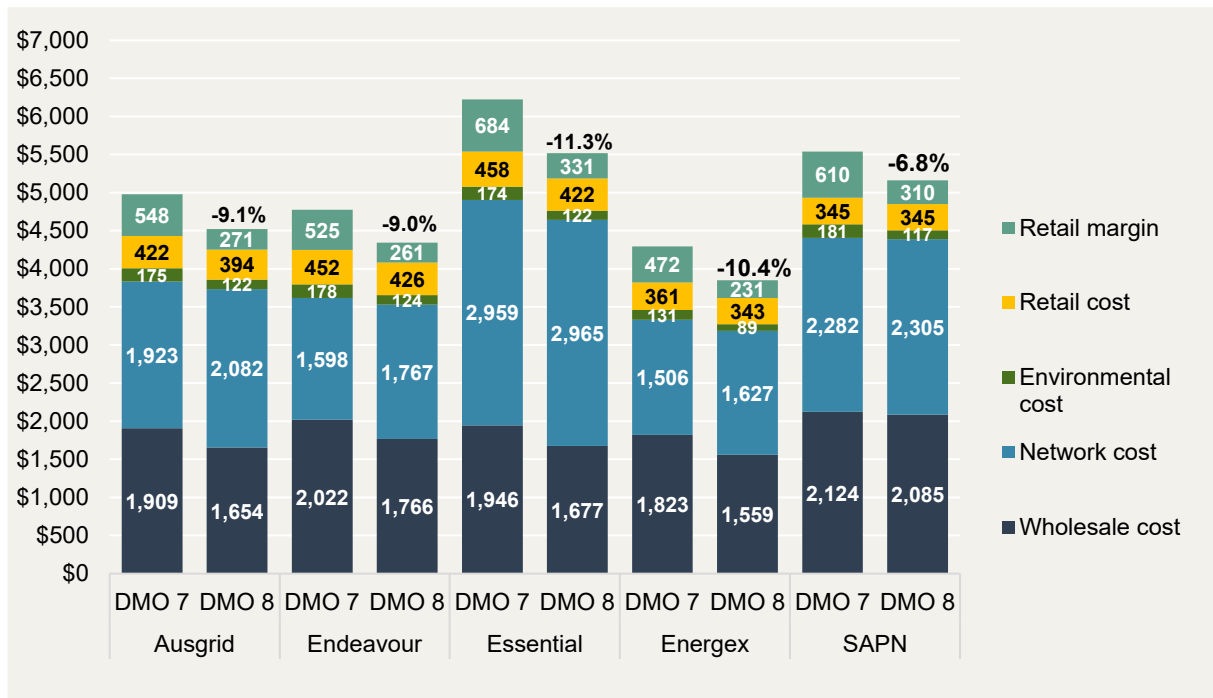


Figure D.2 Small business flat rate percentage change from DMO 7 (nominal)



E Year-on-year and methodological changes to annual prices

The charts in this appendix illustrate year-on-year changes, reflecting both underlying market condition changes and movements in the DMO methodology.

The figure movements in the ‘Methodology changes’ section of the graphs include the wholesale change of moving from the 75th to the 50th percentile of the WEC and including a volatility allowance; network blending of costs across flat rate and time of use tariffs and retail costs applying the standing offer customer-weighted average approach to quantify modest costs to acquire and retain small customers. Specifically for small business, margin changes reflect the retail margin for small business being aligned with the residential margin of 6% in addition to the cumulative impacts of other methodology changes and year-on-year movements for other costs that make up the DMO.

Figure E.1 Ausgrid residential flat rate, inc. GST

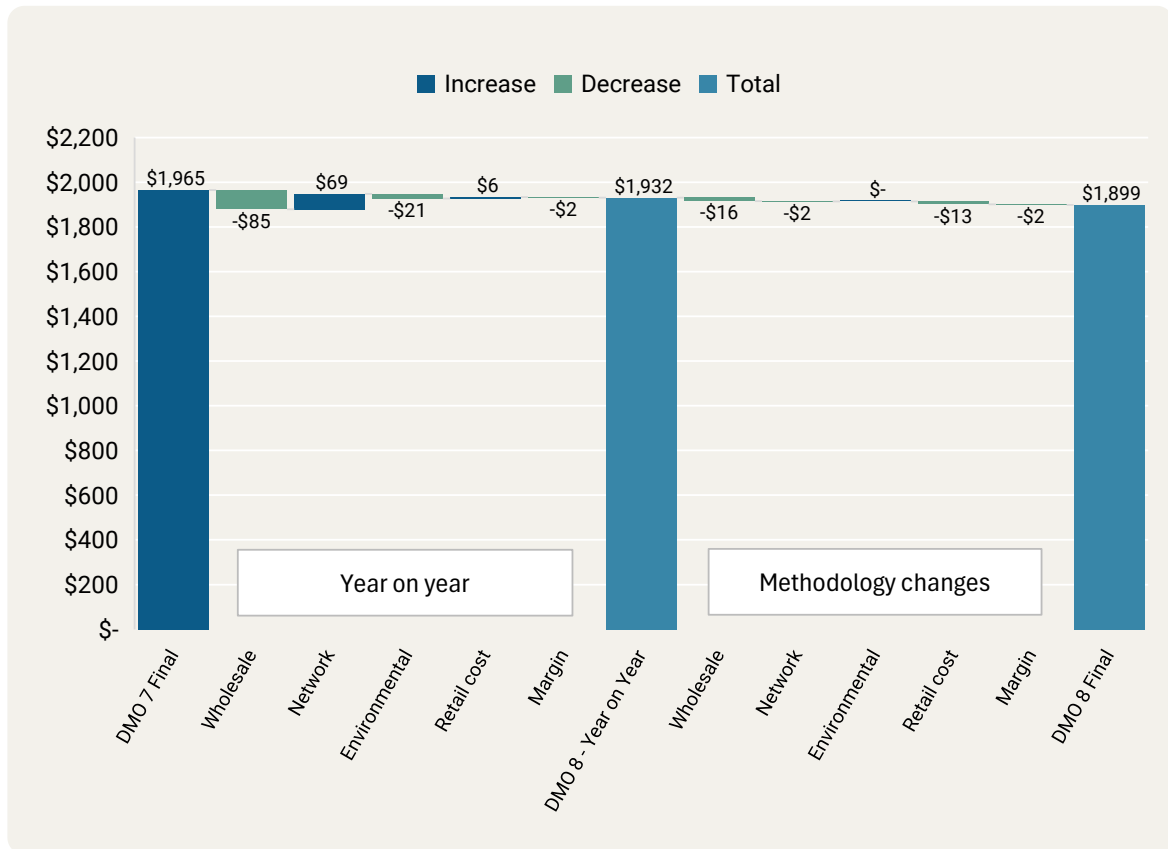


Figure E.2 Ausgrid small business flat rate, inc. GST

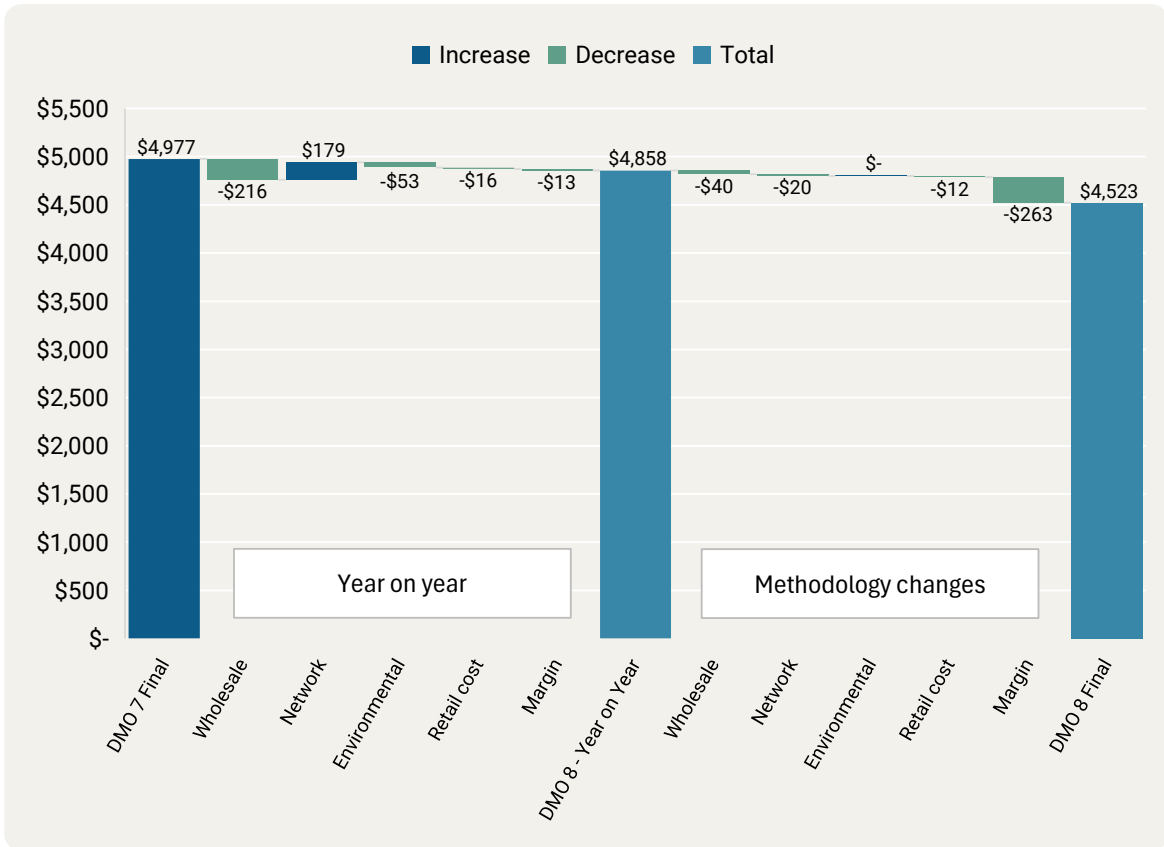


Figure E.3 Endeavour Energy residential flat rate, inc. GST

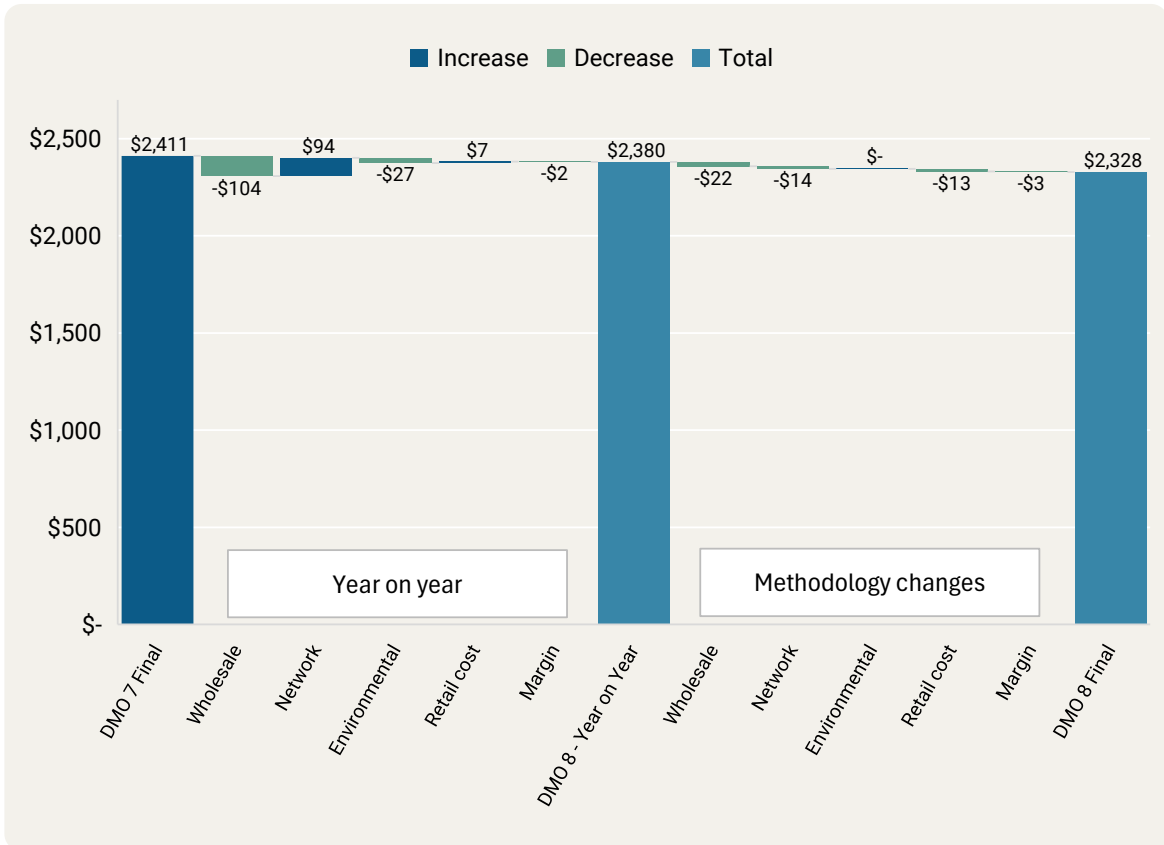


Figure E.4 Endeavour Energy small business flat rate, inc. GST

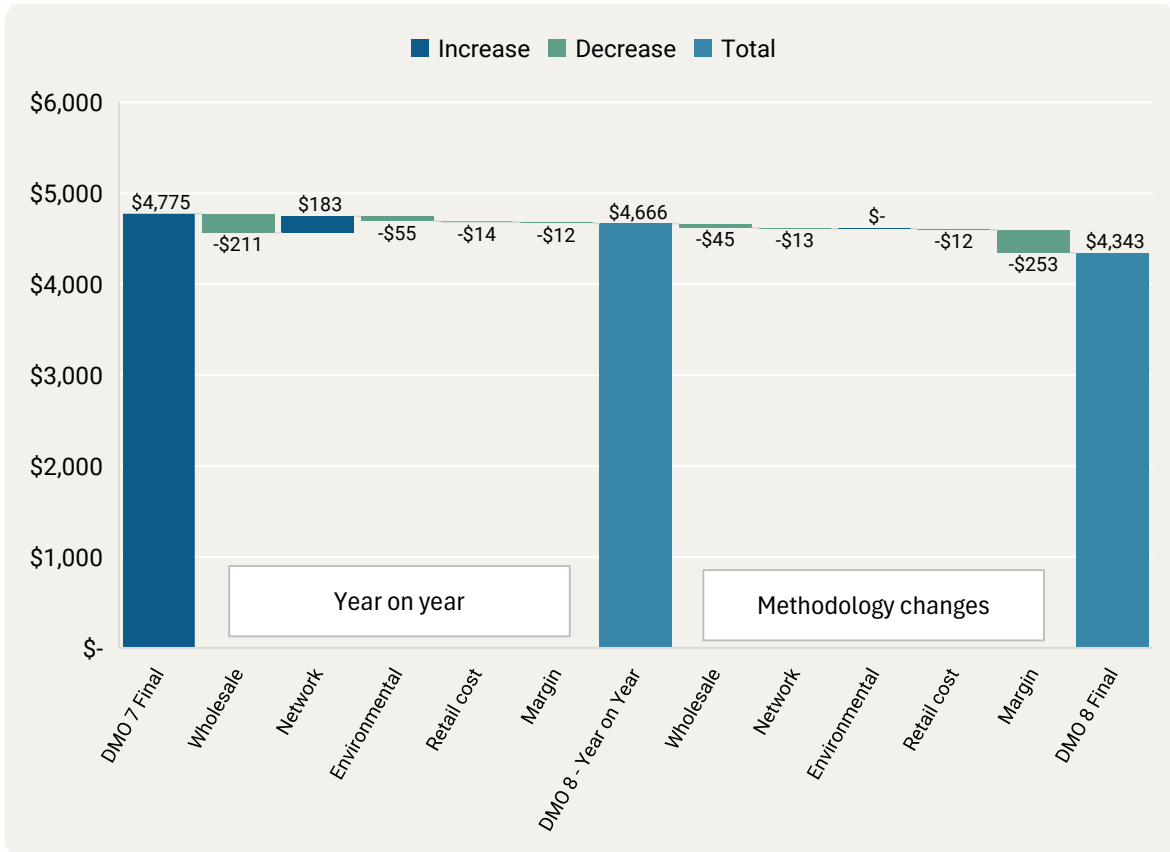


Figure E.5 Essential Energy residential flat rate, inc. GST

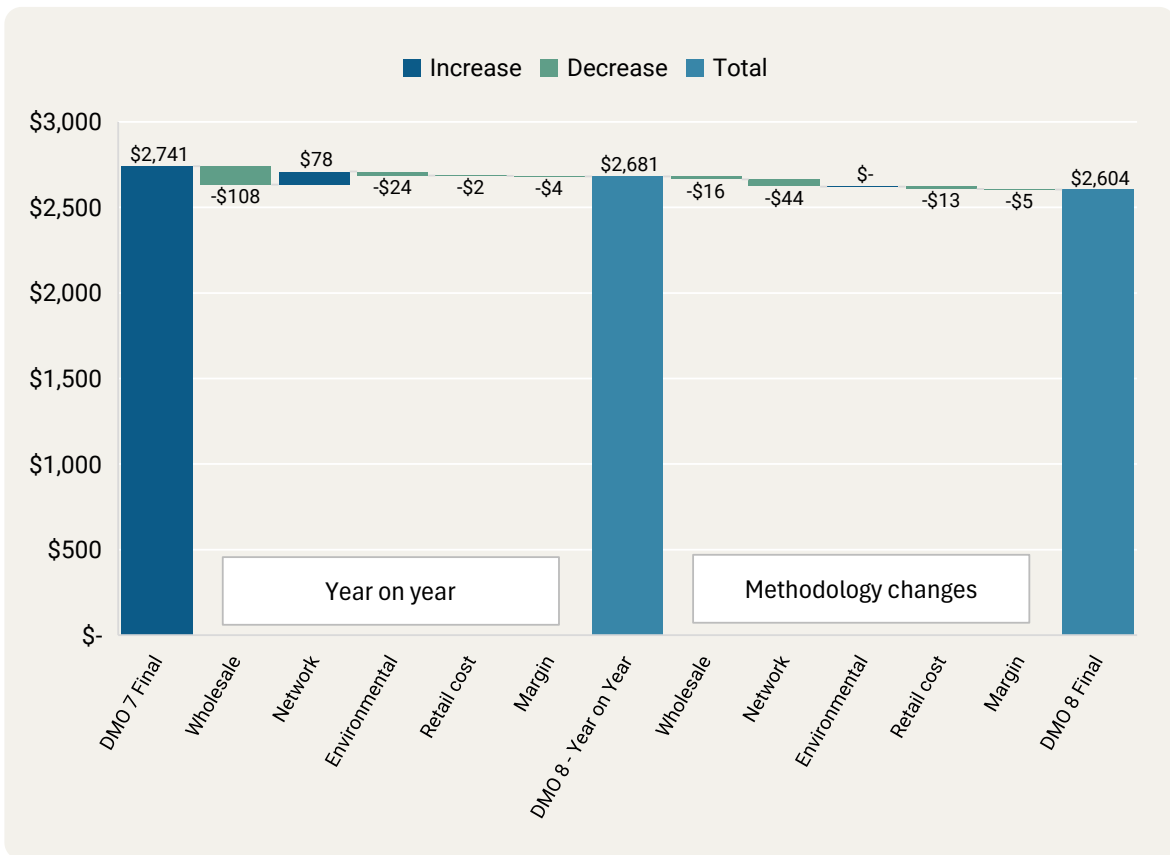


Figure E.6 Essential Energy small business flat rate, inc. GST

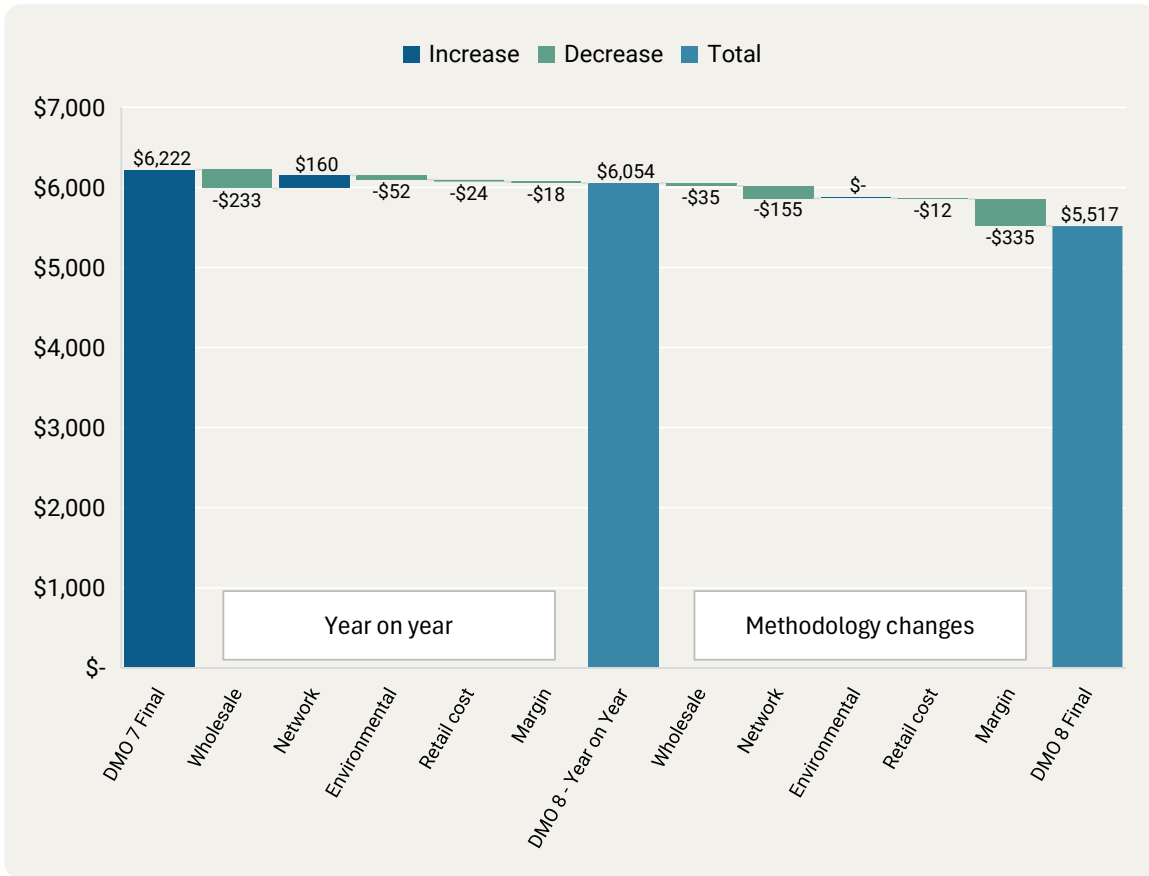


Figure E.7 Energex residential flat rate, inc. GST

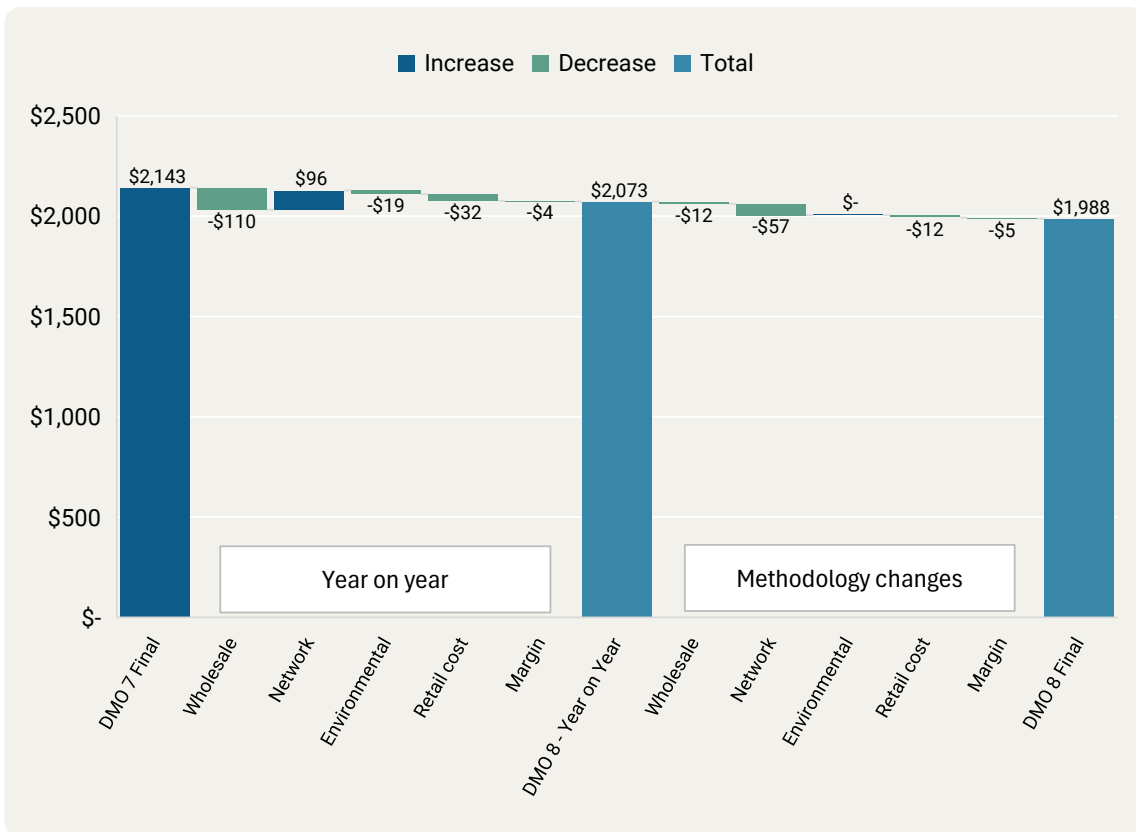


Figure E.8 Energex small business flat rate, inc. GST

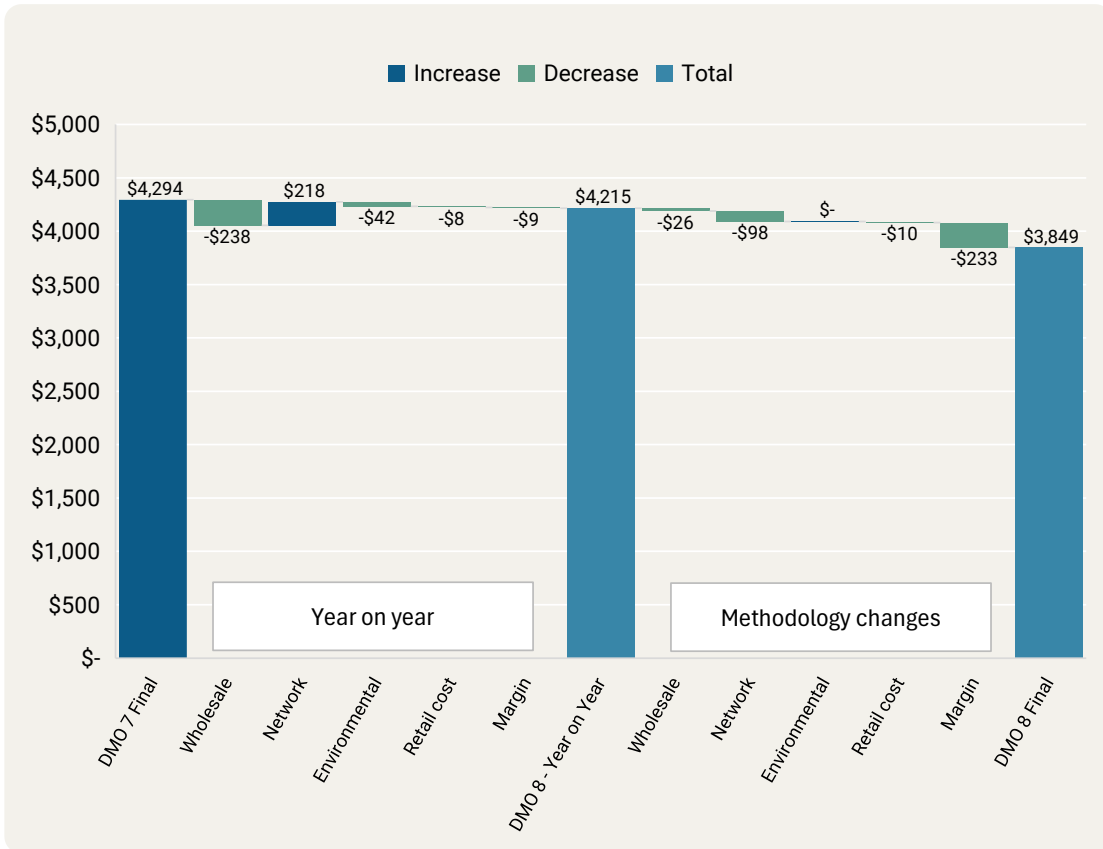


Figure E.9 SA Power Networks residential flat rate, inc. GST

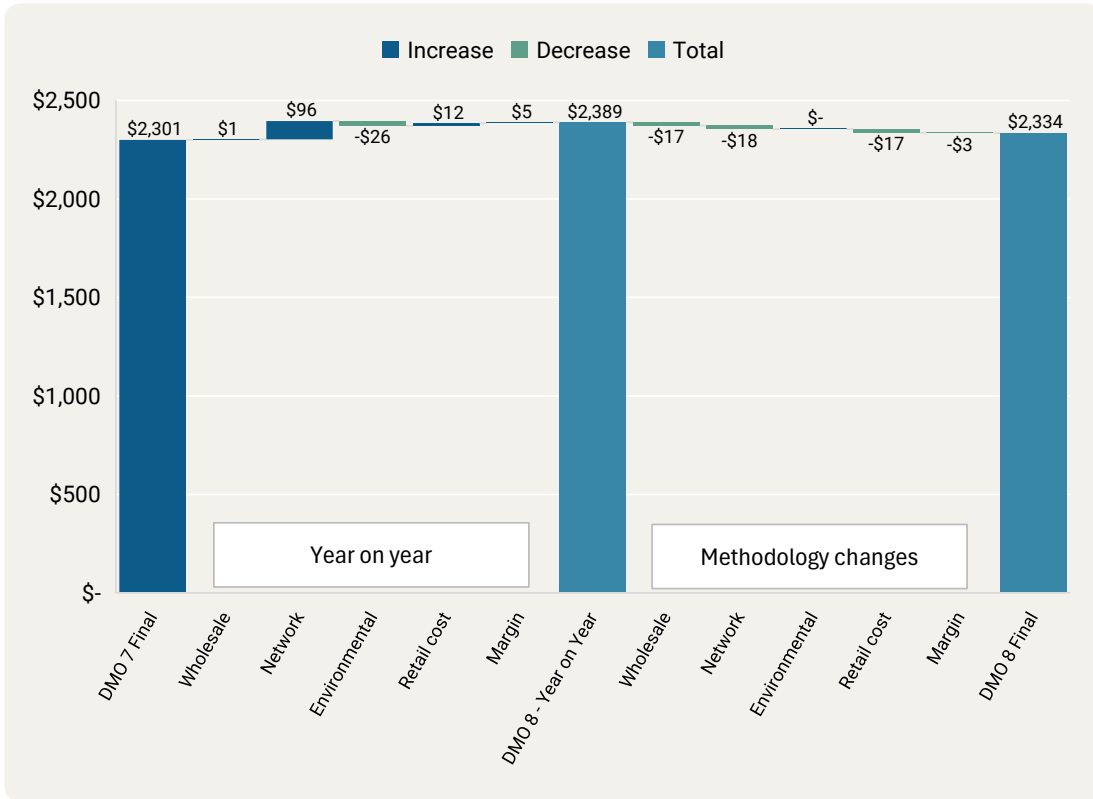
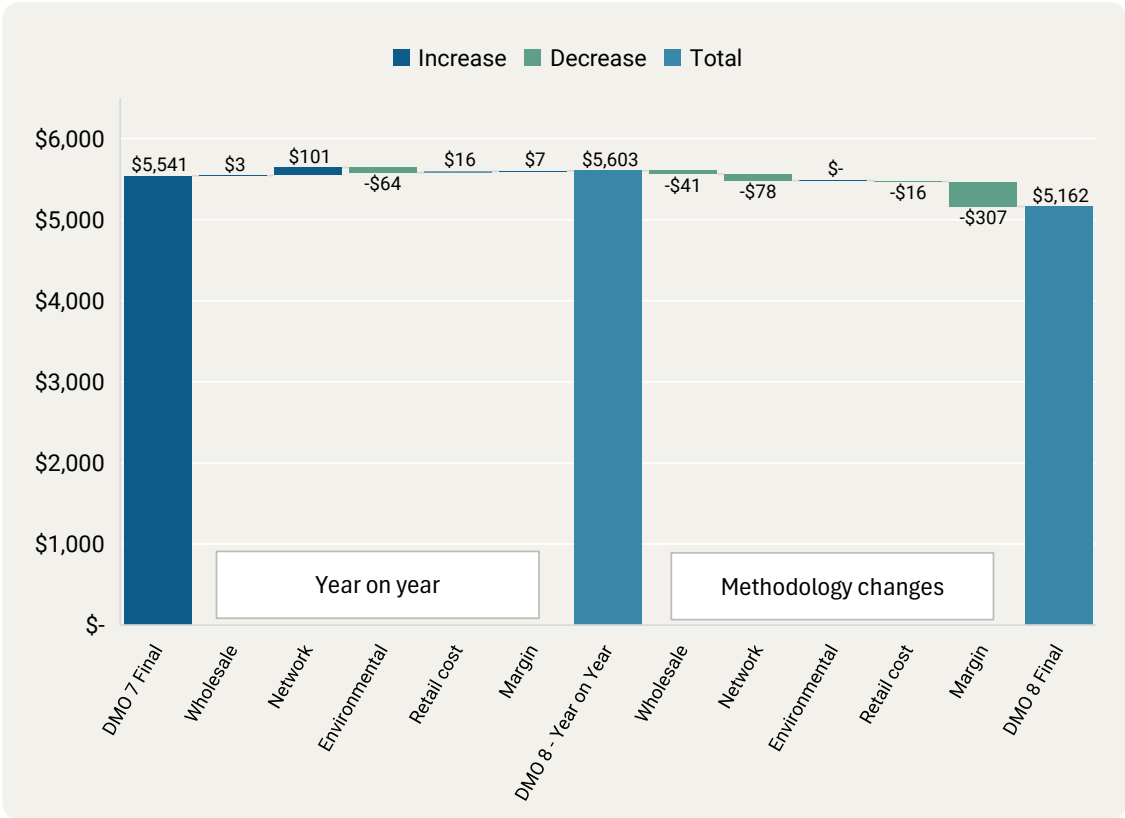


Figure E.10 SA Power Networks small business flat rate, inc. GST



F State-based summaries

This appendix details DMO cost stack changes from the DMO 7 final determination to the DMO 8 draft and final determinations for each state.

New South Wales

Table F.1 Residential flat rate, change from final determination DMO 7 to draft and final determination DMO 8, NSW regions (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Ausgrid	Wholesale cost	753.97	–	673.48	–	653.79	–	-80.49	-10.7%	-19.70	-2.9%	-100.19	-13.3%
	Network cost	711.92	–	743.09	–	778.23	–	31.17	4.4%	35.14	4.7%	66.31	9.3%
	Environmental cost	68.33	–	48.17	–	47.57	–	-20.16	-29.5%	-0.60	-1.2%	-20.76	-30.4%
	Retail cost	312.51	–	297.31	–	305.55	–	-15.21	-4.9%	8.24	2.8%	-6.96	-2.2%
	Retail margin	117.88	6.0%	112.47	6.0%	113.95	6.0%	-5.41	-4.6%	1.47	1.3%	-3.93	-3.3%
	Total	1,965	–	1,875	–	1,899	–	-90	-4.6%	24	1.3%	-66	-3.4%
Endeavour Energy	Wholesale cost	998.46	–	902.76	–	872.63	–	-95.70	-9.6%	-30.13	-3.3%	-125.83	-12.6%
	Network cost	836.51	–	910.76	–	916.59	–	74.26	8.9%	5.82	0.6%	80.08	9.6%
	Environmental cost	87.41	–	61.62	–	60.53	–	-25.79	-29.5%	-1.09	-1.8%	-26.88	-30.8%
	Retail cost	344.31	–	331.36	–	338.94	–	-12.94	-3.8%	7.57	2.3%	-5.37	-1.6%
	Retail margin	144.68	6.0%	140.84	6.0%	139.70	6.0%	-3.84	-2.7%	-1.14	-0.8%	-4.98	-3.4%
	Total	2,411	–	2,347	–	2,328	–	-64	-2.7%	-19	-0.8%	-83	-3.4%
Essential Energy	Wholesale cost	903.45	–	795.52	–	779.32	–	-107.94	-11.9%	-16.19	-2.0%	-124.13	-13.7%
	Network cost	1,248.98	–	1,191.33	–	1,283.03	–	-57.65	-4.6%	91.70	7.7%	34.05	2.7%
	Environmental cost	80.17	–	56.52	–	56.08	–	-23.65	-29.5%	-0.43	-0.8%	-24.09	-30.0%
	Retail cost	343.76	–	321.19	–	329.17	–	-22.58	-6.6%	7.99	2.5%	-14.59	-4.2%
	Retail margin	164.45	6.0%	150.93	6.0%	156.23	6.0%	-13.52	-8.2%	5.30	3.5%	-8.22	-5.0%
	Total	2,741	–	2,515	–	2,604	–	-226	-8.2%	89	3.5%	-137	-5.0%

Table F.2 Residential time of use, change from final determination DMO 7 to draft and final determination DMO 8, NSW regions (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Ausgrid	Wholesale cost	753.97	–	673.48	–	653.79	–	-80.49	-10.7%	-19.70	-2.9%	-100.19	-13.3%
	Network cost	711.92	–	754.24	–	772.78	–	42.32	5.9%	18.54	2.5%	60.86	8.5%
	Environmental cost	68.33	–	48.17	–	47.57	–	-20.16	-29.5%	-0.60	-1.2%	-20.76	-30.4%
	Retail cost	312.51	–	297.31	–	305.55	–	-15.21	-4.9%	8.24	2.8%	-6.96	-2.2%
	Retail margin	117.88	6.0%	113.18	6.0%	113.60	6.0%	-4.69	-4.0%	0.41	0.4%	-4.28	-3.6%
	Total	1,965	–	1,886	–	1,893	–	-79	-4.0%	7	0.4%	-72	-3.7%
Endeavour Energy	Wholesale cost	998.46	–	902.76	–	872.63	–	-95.70	-9.6%	-30.13	-3.3%	-125.83	-12.6%
	Network cost	836.51	–	916.11	–	908.48	–	79.61	9.5%	-7.63	-0.8%	71.97	8.6%
	Environmental cost	87.41	–	61.62	–	60.53	–	-25.79	-29.5%	-1.09	-1.8%	-26.88	-30.8%
	Retail cost	344.31	–	331.36	–	338.94	–	-12.94	-3.8%	7.57	2.3%	-5.37	-1.6%
	Retail margin	144.68	6.0%	141.18	6.0%	139.19	6.0%	-3.50	-2.4%	-2.00	-1.4%	-5.50	-3.8%
	Total	2,411	–	2,353	–	2,320	–	-58	-2.4%	-33	-1.4%	-91	-3.8%
Essential Energy	Wholesale cost	903.45	–	795.52	–	779.32	–	-107.94	-11.9%	-16.19	-2.0%	-124.13	-13.7%
	Network cost	1,248.98	–	1,191.33	–	1,213.29	–	-57.65	-4.6%	21.96	1.8%	-35.69	-2.9%
	Environmental cost	80.17	–	56.52	–	56.08	–	-23.65	-29.5%	-0.43	-0.8%	-24.09	-30.0%
	Retail cost	343.76	–	321.19	–	329.17	–	-22.58	-6.6%	7.99	2.5%	-14.59	-4.2%
	Retail margin	164.45	6.0%	150.93	6.0%	151.78	6.0%	-13.52	-8.2%	0.85	0.6%	-12.67	-7.7%
	Total	2,741	–	2,515	–	2,530	–	-226	-8.2%	15	0.6%	-211	-7.7%

Table F.3 Small business flat rate, change from final determination DMO 7 to draft and final determination DMO 8, NSW regions (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Ausgrid	Wholesale cost	1,909.46	–	1,703.07	–	1,653.79	–	-206.38	-10.8%	-49.29	-2.9%	-255.67	-13.4%
	Network cost	1,923.34	–	1,992.84	–	2,082.28	–	69.50	3.6%	89.44	4.5%	158.94	8.3%
	Environmental cost	175.21	–	123.52	–	121.98	–	-51.69	-29.5%	-1.53	-1.2%	-53.22	-30.4%
	Retail cost	421.95	–	386.50	–	394.00	–	-35.45	-8.4%	7.50	1.9%	-27.95	-6.6%
	Retail margin	547.52	11.0%	268.46	6.0%	271.41	6.0%	-279.06	-51.0%	2.94	1.1%	-276.12	-50.4%
	Total	4,977	–	4,474	–	4,523	–	-503	-10.1%	49	1.1%	-454	-9.1%
Endeavour Energy	Wholesale cost	2,021.84	–	1,826.53	–	1,765.85	–	-195.31	-9.7%	-60.68	-3.3%	-255.99	-12.7%
	Network cost	1,597.55	–	1,731.92	–	1,766.94	–	134.37	8.4%	35.02	2.0%	169.38	10.6%
	Environmental cost	178.38	–	125.75	–	123.52	–	-52.63	-29.5%	-2.23	-1.8%	-54.86	-30.8%
	Retail cost	452.19	–	420.72	–	426.19	–	-31.47	-7.0%	5.47	1.3%	-26.00	-5.8%
	Retail margin	525.28	11.0%	262.02	6.0%	260.58	6.0%	-263.26	-50.1%	-1.43	-0.5%	-264.69	-50.4%
	Total	4,775	–	4,367	–	4,343	–	-408	-8.5%	-24	-0.5%	-432	-9.0%
Essential Energy	Wholesale cost	1,946.16	–	1,711.52	–	1,677.23	–	-234.64	-12.1%	-34.28	-2.0%	-268.93	-13.8%
	Network cost	2,959.14	–	2,358.68	–	2,964.67	–	-600.47	-20.3%	606.00	25.7%	5.53	0.2%
	Environmental cost	174.28	–	122.86	–	121.92	–	-51.42	-29.5%	-0.94	-0.8%	-52.36	-30.0%
	Retail cost	458.05	–	414.62	–	422.44	–	-43.43	-9.5%	7.82	1.9%	-35.60	-7.8%
	Retail margin	684.43	11.0%	294.11	6.0%	331.04	6.0%	-390.32	-57.0%	36.93	12.6%	-353.39	-51.6%
	Total	6,222	–	4,902	–	5,517	–	-1,320	-21.2%	615	12.5%	-705	-11.3%

Table F.4 Small business time of use, change from final determination DMO 7 to draft and final determination DMO 8, NSW regions (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Ausgrid	Wholesale cost	1,909.46	–	1,703.07	–	1,653.79	–	-206.38	-10.8%	-49.29	-2.9%	-255.67	-13.4%
	Network cost	1,923.34	–	2,109.22	–	2,013.64	–	185.88	9.7%	-95.58	-4.5%	90.30	4.7%
	Environmental cost	175.21	–	123.52	–	121.98	–	-51.69	-29.5%	-1.53	-1.2%	-53.22	-30.4%
	Retail cost	421.95	–	386.50	–	394.00	–	-35.45	-8.4%	7.50	1.9%	-27.95	-6.6%
	Retail margin	547.52	11.0%	275.89	6.0%	267.03	6.0%	-271.63	-49.6%	-8.87	-3.2%	-280.50	-51.2%
	Total	4,977	–	4,598	–	4,450	–	-379	-7.6%	-148	-3.2%	-527	-10.6%
Endeavour Energy	Wholesale cost	2,021.84	–	1,826.53	–	1,765.85	–	-195.31	-9.7%	-60.68	-3.3%	-255.99	-12.7%
	Network cost	1,597.55	–	1,759.12	–	1,750.84	–	161.57	10.1%	-8.27	-0.5%	153.29	9.6%
	Environmental cost	178.38	–	125.75	–	123.52	–	-52.63	-29.5%	-2.23	-1.8%	-54.86	-30.8%
	Retail cost	452.19	–	420.72	–	426.19	–	-31.47	-7.0%	5.47	1.3%	-26.00	-5.8%
	Retail margin	525.28	11.0%	263.75	6.0%	259.56	6.0%	-261.52	-49.8%	-4.19	-1.6%	-265.72	-50.6%
	Total	4,775	–	4,396	–	4,326	–	-379	-7.9%	-70	-1.6%	-449	-9.4%
Essential Energy	Wholesale cost	1,946.16	–	1,711.52	–	1,677.23	–	-234.64	-12.1%	-34.28	-2.0%	-268.93	-13.8%
	Network cost	2,959.14	–	2,358.68	–	2,402.02	–	-600.47	-20.3%	43.34	1.8%	-557.13	-18.8%
	Environmental cost	174.28	–	122.86	–	121.92	–	-51.42	-29.5%	-0.94	-0.8%	-52.36	-30.0%
	Retail cost	458.05	–	414.62	–	422.44	–	-43.43	-9.5%	7.82	1.9%	-35.60	-7.8%
	Retail margin	684.43	11.0%	294.11	6.0%	295.12	6.0%	-390.32	-57.0%	1.02	0.3%	-389.30	-56.9%
	Total	6,222	–	4,902	–	4,919	–	-1,320	-21.2%	17	0.3%	-1,303	-20.9%

Queensland

Table F.5 Residential flat rate, change from final determination DMO 7 to draft and final determination DMO 8, Energex (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Energex	Wholesale cost	847.01	–	745.69	–	725.05	–	-101.32	-12.0%	-20.64	-2.8%	-121.95	-14.4%
	Network cost	778.45	–	746.35	–	817.46	–	-32.10	-4.1%	71.11	9.5%	39.01	5.0%
	Environmental cost	60.31	–	42.49	–	40.89	–	-17.82	-29.5%	-1.60	-3.8%	-19.42	-32.2%
	Retail cost	328.20	–	277.31	–	285.01	–	-50.90	-15.5%	7.71	2.8%	-43.19	-13.2%
	Retail margin	128.55	6.0%	115.65	6.0%	119.26	6.0%	-12.90	-10.0%	3.61	3.1%	-9.29	-7.2%
	Total	2,143	–	1,927	–	1,988	–	-216	-10.1%	61	3.2%	-155	-7.2%

Table F.6 Residential time of use, change from final determination DMO 7 to draft and final determination DMO 8, Energex (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Energex	Wholesale cost	847.01	–	745.69	–	725.05	–	-101.32	-12.0%	-20.64	-2.8%	-121.95	-14.4%
	Network cost	778.45	–	746.35	–	747.99	–	-32.10	-4.1%	1.64	0.2%	-30.46	-3.9%
	Environmental cost	60.31	–	42.49	–	40.89	–	-17.82	-29.5%	-1.60	-3.8%	-19.42	-32.2%
	Retail cost	328.20	–	277.31	–	285.01	–	-50.90	-15.5%	7.71	2.8%	-43.19	-13.2%
	Retail margin	128.55	6.0%	115.65	6.0%	114.83	6.0%	-12.90	-10.0%	-0.82	-0.7%	-13.72	-10.7%
	Total	2,143	–	1,927	–	1,914	–	-216	-10.1%	-13	-0.7%	-229	-10.7%

Table F.7 Small business flat rate, change from final determination DMO 7 to draft and final determination DMO 8, Energex (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Energex	Wholesale cost	1,823.45	–	1,603.20	–	1,559.26	–	-220.25	-12.1%	-43.95	-2.7%	-264.20	-14.5%
	Network cost	1,506.37	–	1,486.17	–	1,626.61	–	-20.21	-1.3%	140.45	9.5%	120.24	8.0%
	Environmental cost	131.10	–	92.36	–	88.89	–	-38.74	-29.5%	-3.47	-3.8%	-42.21	-32.2%
	Retail cost	360.66	–	337.91	–	342.86	–	-22.75	-6.3%	4.95	1.5%	-17.80	-4.9%
	Retail margin	472.33	11.0%	224.66	6.0%	230.91	6.0%	-247.67	-52.4%	6.25	2.8%	-241.42	-51.1%
	Total	4,294	–	3,744	–	3,849	–	-550	-12.8%	105	2.8%	-445	-10.4%

Table F.8 Small business time of use, change from final determination DMO 7 to draft and final determination DMO 8, Energex (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
Energex	Wholesale cost	1,823.45	–	1,603.20	–	1,559.26	–	-220.25	-12.1%	-43.95	-2.7%	-264.20	-14.5%
	Network cost	1,506.37	–	1,486.17	–	1,480.12	–	-20.21	-1.3%	-6.04	-0.4%	-26.25	-1.7%
	Environmental cost	131.10	–	92.36	–	88.89	–	-38.74	-29.5%	-3.47	-3.8%	-42.21	-32.2%
	Retail cost	360.66	–	337.91	–	342.86	–	-22.75	-6.3%	4.95	1.5%	-17.80	-4.9%
	Retail margin	472.33	11.0%	224.66	6.0%	221.56	6.0%	-247.67	-52.4%	-3.10	-1.4%	-250.77	-53.1%
	Total	4,294	–	3,744	–	3,693	–	-550	-12.8%	-51	-1.4%	-601	-14.0%

South Australia

Table F.9 Residential flat rate, change from final determination DMO 7 to draft and final determination DMO 8, SA Power Networks (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
SA Power Networks	Wholesale cost	858.80	–	834.55	–	842.80	–	-24.24	-2.8%	8.25	1.0%	-15.99	-1.9%
	Network cost	896.99	–	930.67	–	974.34	–	33.67	3.8%	43.68	4.7%	77.35	8.6%
	Environmental cost	72.25	–	46.34	–	46.72	–	-25.91	-35.9%	0.39	0.8%	-25.53	-35.3%
	Retail cost	334.47	–	321.89	–	329.72	–	-12.58	-3.8%	7.82	2.4%	-4.76	-1.4%
	Retail margin	138.03	6.0%	136.18	6.0%	140.02	6.0%	-1.86	-1.3%	3.84	2.8%	1.98	1.4%
	Total	2,301	–	2,270	–	2,334	–	-31	-1.3%	64	2.8%	33	1.4%

Table F.10 Residential time of use, change from final determination DMO 7 to draft and final determination DMO 8, SA Power Networks (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
SA Power Networks	Wholesale cost	858.80	–	834.55	–	842.80	–	-24.24	-2.8%	8.25	1.0%	-15.99	-1.9%
	Network cost	896.99	–	930.67	–	919.90	–	33.67	3.8%	-10.77	-1.2%	22.91	2.6%
	Environmental cost	72.25	–	46.34	–	46.72	–	-25.91	-35.9%	0.39	0.8%	-25.53	-35.3%
	Retail cost	334.47	–	321.89	–	329.72	–	-12.58	-3.8%	7.82	2.4%	-4.76	-1.4%
	Retail margin	138.03	6.0%	136.18	6.0%	136.54	6.0%	-1.86	-1.3%	0.36	0.3%	-1.49	-1.1%
	Total	2,301	–	2,270	–	2,276	–	-31	-1.3%	6	0.3%	-25	-1.1%

Table F.11 Small business flat rate, change from final determination DMO 7 to draft and final determination DMO 8, SA Power Networks (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
SA Power Networks	Wholesale cost	2,124.17	–	2,063.56	–	2,085.35	–	-60.61	-2.9%	21.80	1.1%	-38.82	-1.8%
	Network cost	2,281.98	–	1,897.99	–	2,305.03	–	-383.99	-16.8%	407.04	21.4%	23.05	1.0%
	Environmental cost	180.62	–	115.84	–	116.80	–	-64.78	-35.9%	0.96	0.8%	-63.81	-35.3%
	Retail cost	344.73	–	336.61	–	344.97	–	-8.12	-2.4%	8.36	2.5%	0.24	0.1%
	Retail margin	609.51	11.0%	281.74	6.0%	309.71	6.0%	-327.77	-53.8%	27.97	9.9%	-299.80	-49.2%
	Total	5,541	–	4,696	–	5,162	–	-845	-15.2%	466	9.9%	-379	-6.8%

Table F.12 Small business time of use, change from final determination DMO 7 to draft and final determination DMO 8, SA Power Networks (nominal)

Distribution region	Cost stack component	Final determination DMO 7 2025–26		Draft determination DMO 8 2026–27		Final determination DMO 8 2026–27		Difference from DMO 7 to draft DMO 8		Difference from DMO 8 draft to final		Difference from DMO 7 to final DMO 8	
		inc. GST	margin	inc. GST	margin	inc. GST	margin	\$ diff	% diff	\$ diff	% diff	\$ diff	% diff
SA Power Networks	Wholesale cost	2,124.17	–	2,063.56	–	2,085.35	–	-60.61	-2.9%	21.80	1.1%	-38.82	-1.8%
	Network cost	2,281.98	–	1,897.99	–	2,028.43	–	-383.99	-16.8%	130.44	6.9%	-253.55	-11.1%
	Environmental cost	180.62	–	115.84	–	116.80	–	-64.78	-35.9%	0.96	0.8%	-63.81	-35.3%
	Retail cost	344.73	–	336.61	–	344.97	–	-8.12	-2.4%	8.36	2.5%	0.24	0.1%
	Retail margin	609.51	11.0%	281.74	6.0%	292.06	6.0%	-327.77	-53.8%	10.31	3.7%	-317.45	-52.1%
	Total	5,541	–	4,696	–	4,868	–	-845	-15.2%	172	3.7%	-673	-12.1%

G Breakdown of retail and other costs

Further to the AEC and Origin Energy’s concerns around transparency in the underlying retail cost data and how the AER has arrived at these retail cost estimates, we provided a comparison of the retail cost subcomponents, including the costs to serve, costs to acquire and retain customers, and other costs from DMO 7 to DMO 8. These disaggregations are presented by customer type and DMO region.

Figure G.1 and Figure G.2 show that retail and other costs have decreased from DMO 7 to DMO 8 across all DMO regions, for residential and small business customers, respectively. Overall, all retail and other cost sub-components have declined for both customer types, including costs to serve, acquisition and retention costs, and other costs.

These declines are mainly driven from lower reported retailer costs compared with 2023–24 (used in DMO 7), which were further compounded by applying the standing offer customer-weighted average to quantify modest costs to acquire and retain customers.

Figure G.1 Comparison of DMO 7 and DMO 8 retail and other cost sub-components, residential customers, by DMO region and customer type, ex. GST

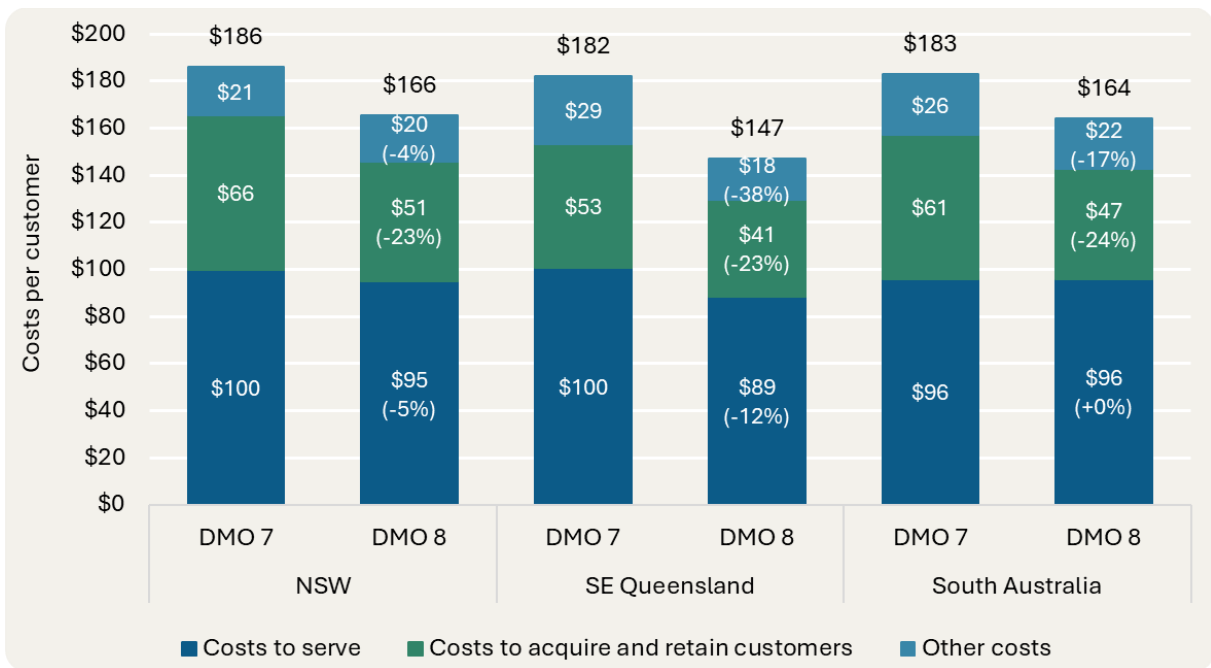


Figure G.2 Comparison of DMO 7 and DMO 8 retail and other cost sub-components, small businesses, by DMO region and customer type, ex. GST

