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Adam Day
A/g Executive Director
Market Performance
Australian Energy Regulator
By email: DMO@aer.gov.au

EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 19
Two Melbourne Quarter
697 Collins Street
Docklands Victoria 3008

Phone +61 3 9060 0000
Facsimile +61 3 9060 0006

enq@energyaustralia.com.au
energyaustralia.com.au

AER Default market offer prices 2025-26 Issues paper

EnergyAustralia is one of Australia's largest energy companies with around 2.2 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 5,000MW of generation capacity.

EnergyAustralia welcomes the opportunity to make this submission to the AER's Issues Paper on the Default Market Offer for 2026-27 (DMO8). We recognise the complexity of the AER progressing DMO8, particularly given the concurrent reforms under the Government's DMO Framework Review. Notably, DMO8 encompasses a significant number of changes—including the proposed introduction of the Solar Sharer offer—within a single review cycle. These reforms are occurring alongside broader industry changes, with the sector preparing for a major transition on 1 July 2027 as the Solar Sharer offer and other significant consumer-focused reforms take effect. This concentration of reforms is unprecedented in recent DMO processes and amplifies the risk of unforeseen knock-on effects for both retailers and customers.

Importantly, both the AER and industry are navigating these reforms without the benefit of finalised legislation, which is likely to have a material bearing on the regulatory methods and outcomes. In this environment, stakeholders are, to some extent, "flying blind"—making it even more critical that the DMO8 process is approached with particular care. Any changes, including those to methodology, should be made with a clear understanding of their cumulative impact on customers, retailers, and the broader energy market, and with a recognition of the added risk that uncertainty brings.

In this submission, we focus on the proposed new DMO policy objective and price-setting approach, while reserving comment on the proposed expansion to embedded network customers for future consultations and the DMO9 price setting.

As the DMO framework transitions towards an 'efficient' tariff price cap, we reiterate—consistent with our July 2025 submission—that affordability for customers is shaped by a range of broader cost drivers, including network, wholesale, and regulatory costs. As reforms progress and the market evolves, it is vital that the DMO reflects the true cost pressures across the energy supply chain.

A neutral and even-handed application of the new DMO framework is key

The introduction of a new guiding DMO objective to an 'efficient' tariff cap approach is a material shift in the DMO regulatory framework. It is critical that in revising the DMO parameters under this new objective the AER's interpretation reflects:

- **Competitive neutrality and sector sustainability**– The DMO must be fair for standing offer customers, but also for retailers of every scale. Designing DMO settings around the cost structures of only certain retailer types- risks undermining the viability of others and may unintentionally drive market consolidation or concentration. These risks are amplified by the cumulative set of changes proposed for DMO8, at a time when retailers continue to absorb rising network costs and are expected to support investment in the energy transition. A DMO that undermines cost recovery threatens both competitive neutrality and the sector's capacity to invest in system reliability and decarbonisation.

- **Dynamic and allocative efficiency** –There is no clear or meaningful distinction between the cost of serving standing offer or market offer customers. We expect that for all retailers - billing systems, service channels, communications, compliance and retention - are shared across the entire customer base. New regulatory requirements, including expiry of benefit periods and rolling onto the standing offer, mean customers move more frequently between these two groups. Setting the DMO based on a narrow retailer cost base or static assumptions (i.e. that standing offer customers are static and disengaged) risks both undermining allocative efficiency by misrepresenting the real cost to serve – and dynamic efficiency, by limiting retailers' ability to adapt, innovate and compete.

- **Avoiding unintended customer consequences:** A price cap that is set too low or becomes overly restrictive can compress price differences between offers. This, in turn, reduces incentives for retailers to innovate or differentiate their products, and erode the value proposition for customers who are willing to engage and shop around. These effects have already been observed to some extent [1]as price regulation has become tighter and therefore should be carefully considered in the DMO8 design.

We encourage the AER to adopt a pragmatic interpretation of undefined mandatory considerations it must consider under the new DMO objective and aim for:

- **Stability and predictability**, avoiding annual reinterpretation

- **Simplicity**, minimising unnecessary complexity, and

- **Consistency with past DMO regulatory principles**, unless there is strong evidence to depart - particularly given the breadth and pace of proposed changes in DMO8.

The proposed new DMO guideline can support these objectives. While it is not expected to be binding, the DMO guideline can enhance regulatory certainty by setting out the AER's approach to cost components, data sources, and the process for annual

[1] For example see: ACCC, *Electricity Market Inquiry Report*, December 2023 ACCC Media Release.

determinations. This allows stakeholders to expect continuity for most aspects of DMO, with consultation focused on substantive changes.

To strengthen transparency and trust, the AER should explain any departures from the DMO guideline and commit to at least four weeks' advance notice before implementing such changes, ensuring industry is not exposed to last-minute DMO outcomes.

We reserve further comments and engagement on the DMO guideline for future consultations.

Our full submission with responses to key questions in the Issues paper is in the Attachment. If you have any questions in relation to this submission, please contact me (maria.ducusin@energyaustralia.com.au or 03 9060 0934).

Yours sincerely,

Maria Ducusin
Regulatory Policy Manager

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

The proposed apportionment of cost elements set out in Figure 3.1 appears broadly appropriate.

As discussed, given the extensive changes proposed in DMO8, we recommend that revisions to the wholesale cost percentile, bad debt, and margins be approached with caution. These elements are particularly sensitive to methodological changes, and careful consideration is needed to ensure that adjustments do not have unintended impacts on customers or retailers.

Question 2: How should the AER determine maximum annual bill (MAB) amounts?

The maximum annual bill should be calculated using the flat tariff for each distribution zone. This provides a single, consistent reference point and is the only practical way to ensure comparability across all tariff types.

A single MAB promotes clarity for customers. Introducing multiple maximum annual bills for different tariff types within the same distribution area would add unnecessary complexity and increase the risk of customer misunderstanding.

If a regulated TOU tariff cap, when applied to benchmark usage using the AEMO 48-interval profile, results in an annual bill below the flat-tariff MAB, this is not problematic. It simply reflects that TOU outcomes may be favourable for a typical customer and does not undermine the purpose of a single reference point.

The MAB should only be set for the primary load. It should not be required for controlled-load combinations. Controlled load rates could flow directly from the flat-tariff caps, and TOU-related controlled load rates could also be derived from the same flat-tariff base if the AER adopts the proposed approach.

Challenges of demand tariffs and price comparison to the MAB

In principle, demand tariffs could also be regulated using the same maximum bill that is applied to TOU tariffs—that is, a single MAB derived from the flat tariff cap. This ensures consistency and maintains the MAB as an overall ceiling across all tariff structures.

However, we consider that implementing this effectively in practice requires a robust and agreed method for determining a representative level of kW demand for the benchmark usage (e.g., 3,900 kWh in Ausgrid). Demand tariffs introduce additional complexity because they include a third billable component—demand measured in kW—and determining a typical demand value is not straightforward.

The kW reading will vary depending on the conditions and time windows used for the demand period. Using an average demand from distributor data is not necessarily appropriate, as this assumes that retailers apply identical demand conditions and windows to networks, which is not always the case. Distributor averages may also not reflect the benchmark usage, given that average consumption for that cohort can differ from the benchmark. Some form of scaling may be required to align calculated demand values with the benchmark, but the relationship between demand and usage is not linear—introducing further uncertainty and methodological risk.

As a comparison, the ESC's Victorian Default Offer requires retailers to publish a "representative kW demand" at the benchmark usage to demonstrate compliance.

However, because demand tariffs for small customer classes are relatively rare in Victoria, it is unclear how closely the ESC monitors the reasonableness of the published values. Robust oversight is essential to ensure that published demand figures are fair, reasonable, and reflective of typical customer usage. Without appropriate scrutiny, there is a risk that unreasonably low or high demand values could be reported. Any demand tariff method adopted must therefore ensure that:

(a) the DMO delivers efficient, fair, and transparent outcomes for customers; and
(b) retailers are not subject to unnecessary regulatory burden or compliance uncertainty.

Deferring demand tariff methodology to a later stage appears prudent

Given the material challenges associated with determining representative demand values, and the significant number of reforms already being progressed under DMO8, we consider it prudent for the AER to delay detailed consideration of demand tariffs until at least DMO9.

This would allow the AER to consult more thoroughly, develop a method that is robust and transparent, and avoid creating unintended impacts or unnecessary complexity in the current review cycle. Taking additional time will also ensure that any demand-tariff methodology adopted in future is workable for both retailers and customers.

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

We consider the answer depends heavily on the AER's broader approach to regulating time-of-use (TOU) tariffs under the proposed framework. There appears to be two options for how network costs could be determined.

Option 1: Use the corresponding network tariff for each retail tariff.

If the AER intends to set a TOU DMO tariff cap (in addition to the proposed free-period TOU 'Solar Sharer Offer') and model it directly on a particular network tariff and its structure, then it is logical and appropriate to use the *corresponding* network tariff for that retail tariff.

The more challenging question is which network TOU tariff should be used in distribution zones where multiple TOU network options exist.

For long-term stability, transparency, and to support customer understanding, the AER should consider aligning a TOU DMO tariff with the default network tariff assignment in each distribution zone.

While the default tariff may not currently be the most commonly assigned, it is the tariff that will expand over time, as defaults generally change only once per Tariff Structure statement (TSS) cycle.

Aligning with the default tariff therefore provides a more stable regulatory anchor and avoids frequent changes to the DMO's TOU structure as customer volumes shift between network tariffs.

This approach would allow the AER to adjust the TOU DMO structure only once per five-year TSS period rather than toggling between tariff types based on short-term movements in customer numbers.

Option 2: Use the flat tariff as a single comparison for all tariff types

Alternatively, if the AER adopts our preferred approach of setting the MAB using the flat tariff as a single comparison for all tariff types – including TOU – then there is no need to consider any other underlying network tariffs when building up costs of MAB, even in zones with multiple TOU network options. Under this approach, the flat tariff could provide a consistent and practical basis for comparison, simplifying regulatory process and supporting clarity for customers and retailers.

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

As outlined in our response to Question 2, we consider the most appropriate approach is to set a single MAB for each distribution zone, determined using the flat retail tariff under the DMO tariff cap.

Under this approach, there is no need to develop a blended network cost for the MAB. A single network tariff—the flat network tariff—provides the simplest and clearest basis for comparison.

If any TOU DMO tariffs, when applied to benchmark usage using the AEMO interval profile, produce an annual bill below the flat-tariff MAB, this is a positive outcome. It indicates that TOU tariffs provide a benefit for typical customers and should help promote their adoption where appropriate.

Using the flat tariff to set the MAB is consistent with the ESC's approach under the VDO, which has proven effective and easy for customers to understand.

A single MAB also avoids confusion for customers and retailers about which maximum bill to use when comparing different tariff types. Introducing multiple MABs within the same distribution zone would only increase complexity without adding meaningful value.

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

If the Regulations do not change, the AER should continue to use the flat network tariff to derive network costs, consistent with the current approach.

While the rollout of smart meters is increasing the number of customers assigned to cost-reflective network tariffs, a large proportion of customers remain on flat retail tariffs due to broader regulatory requirements. This includes upcoming AEMC reforms under the LMRP, which introduce consent requirements and continue to support flat retail offerings.

In addition, mandatory obligations in South Australia and Queensland require retailers to offer a flat standing offer upon request, meaning retailers must maintain flat retail tariffs for these customers regardless of their underlying network assignment.

Retailers can carry material risk where they cannot pass through the underlying cost-reflective network tariff and must absorb mismatches between network and retail tariff structures.

Given these factors, continuing with the flat network tariff provides regulatory stability, avoids unnecessary complexity and aligns with existing obligations faced by retailers.

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

We consider the most practical and stable approach would mirror the residential method: derive TOU network costs based on the annual bill from the flat tariff cap, rather than attempting to blend multiple underlying network tariffs.

Using the flat tariff cap as the anchor for small business (SME) DMO tariffs ensures consistency across residential and SME customers, reducing regulatory complexity and maintaining a coherent methodology.

SME customers face the same challenges as residential customers in understanding multiple tariff structures. A single flat-tariff-based point of comparison will avoid confusion and support clearer tariff communications and marketing.

Small business network tariffs vary significantly across distributors, and in many regions multiple SME TOU network tariffs exist. Attempting to blend these would introduce unnecessary complexity, require additional assumptions, and risk creating unstable or hard-to-interpret outcomes.

Using the flat tariff cap as the reference point also ensures that any benefits of TOU tariffs—where they deliver a lower annual bill—are visible to customers and can be promoted transparently by retailers.

Importantly, this approach avoids the risk of SME customers being benchmarked against a network blend that may not reflect their actual tariff assignment, reducing the likelihood of mismatch risk or inadvertent cross-subsidies.

Question 7: what approach for multiple TOU network tariff?
As per commentary in question 3, use of the network's default tariff in their current Tariff Structure statement would be the most sensible choice.

In light of the diversity of TOU products, focussing on the SSO seems pragmatic

TOU products are highly retailer-specific, with significant variation in structure, time periods, and design features. In regions with multiple TOU network tariffs, a centrally defined cap may not always reflect this diversity or local network arrangements.
We see value in focusing regulatory effort on the Solar Sharer Offer (SSO), while providing retailers with flexibility to design other TOU offers that suit their systems and customer base. In such cases, compliance could be demonstrated by comparing the annual bill of any TOU offer against the single flat-tariff MAB as discussed, rather than requiring a regulated TOU cap for one possible TOU configuration.

Wholesale costs

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

We do **not** support shifting to the 50th percentile. It is not reasonable to move to the 50th percentile WEC estimate which as demonstrated, through the AER's own analysis that this has only recovered costs in 84% of cases.[2] This level of risk is inconsistent with the principle that the DMO should permit recovery of efficient hedged costs.

The back-cast results cannot be interpreted as evidence of "efficient" costs. Given the AER's own acknowledgement that the wholesale cost model is simplified, uses stylised hedging assumptions, and has historically underestimated volatility. The observed

[2] Australian Energy Regulator (AER), *Assessing the performance of the wholesale cost model: Supplementary report for the DMO 8 issues paper*, November 2025, pp. 22–26.

failure rate of 16% almost undoubtedly understates real-world risk. As such, the back-cast should not be relied upon as justification for increasing retailer exposure by shifting to the 50th percentile.

Looking ahead, the heightened uncertainty in coming years increases the need for a buffer. Over the next three to five years, the NEM is expected to experience increased volatility due to greater penetration of variable renewable energy (VRE) and evolving policy settings. The Issues Paper itself discusses that these changes may significantly alter market dynamics, including new DMO obligations, mandatory considerations, and CER-driven load shape changes. In this environment, reducing the risk buffer by adopting the 50th percentile would be imprudent.

Furthermore, retailer risk is asymmetric: the consequences of under-recovery are far more severe than those of conservative hedging. Retailers face much greater downside from under-recovery than upside from conservative hedging, and the regulated DMO should not systematically transfer risk onto retailers.

For these reasons, we consider it prudent to retain the 75th percentile at a minimum.

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

The question of a separate volatility allowance is arguably unnecessary if the AER retains the 75th percentile in its cost estimates, as this percentile already incorporates a buffer for cost variability. Moving to the 50th percentile and then layering on a volatility allowance may not replicate the coverage provided by the 75th percentile and introduces unnecessary complexity and risk of underestimation.

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

We do not agree that the 50th percentile is the appropriate benchmark. As discussed, back-cast analysis shows that a 50^{th} percentile-based estimate would fail to capture the frequency and magnitude of higher-cost outcomes in all instances, meaning it does not fully reflect the efficient costs of supply.

By contrast, based on the AER's back-cast analysis, the 75th percentile has generally provided a more robust buffer for cost recovery than the 50th percentile across regions and years, although not in all cases.[3] This supports retaining at least the 75th percentile.

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

The suggested parameters such as liquidity and tradability suggested by the AER appears practical and sensible for assessing new products. Limited ASX trading for some new products may reflect the use of OTC hedges by participants rather than any deficiency in the products themselves.

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

We acknowledge AER's proposed WEC-scaling method and recommend that the AER provide more detailed, bottom-up information for each time-of-use period (e.g., peak,

[3] In some years/regions (e.g., Essential 2021–22 & 2023–24; Energex 2022–23 & 2023–24) actual WECs exceeded the 75th percentile, and in Energex 2023–24 exceeded all modelled percentiles.

shoulder, off-peak), rather than rely solely on broad averages or aggregated allocations. Specifically, retailers could benefit from clearer disclosure of:

- The hours and days defining each TOU period.
- The underlying wholesale price data and load profiles used to calculate costs for each period.
- The cost build-up and risk assumptions applied within each time window.

This level of granularity can help retailers better align risk management and hedging strategies with regulated benchmarks.

Importantly, we consider that TOU WEC estimation is only relevant if the AER proceeds with a TOU tariff cap, such as for the Solar Sharer Offer or any other regulated TOU standing offer tariff cap. If no TOU tariff caps are set, there is no need to estimate TOU WECs.

Retail and other costs

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

We suggest caution in approaches that differentiate the costs of serving specific customer types. In practice, there is little distinction between standing offer and market offer customers, as functions such as billing, service channels, communications, compliance, and retention are largely shared. Regulatory changes, including automatic switching and expiry of benefit periods, mean customers move frequently between these groups.

Efficient costs should reflect the prudent, actual costs across the small customer base, with transparent allocation of shared costs and consideration of variability. Approaches that assume standing offer customers are fixed or disengaged may not accurately reflect the real cost to serve.

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

We suggest the AER adopts a pragmatic approach to defining a 'modest' cost to acquire and retain customers (CARC). In our view, a modest CARC should reflect the minimum prudent spend needed to ensure standing-offer customers can understand their options, interact with their retailer, and access clear, comparable information—while still supporting competition and the DMO's objectives.

It's also important to recognise that, in practice, standing-offer and market-offer customers can't be easily separated. The core functions that drive these costs—such as billing, service, communications, compliance, and retention—are shared across the small-customer base. As a result, there is no meaningful distinction in costs between these customer types, and any attempt to allocate CARC on this basis risks misrepresenting the efficient cost of supply. Recent regulatory changes, such as the expiry of benefit periods resulting in customers rolling onto standing offers, will only further blur any remaining distinction between these groups.

With this in mind, we believe the existing approach to CARC remains appropriate, but should be open to careful, evidence-based adjustment. If revisions are needed, these could be informed by a smaller, representative sample or a transparent statistical method—such as a fixed percentage discount—rather than relying on the historic ESC 2013–14 dataset, which no longer reflects current market conditions.

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

Bad debt should be allocated entirely to the fixed component, reflecting the fact that it can occur even when customers have little or no usage. Many costs that drive bad debt—such as billing, account management, and collections—are largely independent of consumption. Allocating bad debt to the fixed component is practical, avoids unnecessary complexity, and is consistent with other regulators' approaches such as the ESC.

Retail Margin

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

We support maintaining the existing **percentage-based retail margin** across the total DMO cost stack for residential and small business customers (6% and 11%), due to its transparency, simplicity, and ease of application. This provides a stable return amid uncertainty in other cost components, such as wholesale energy, network charges, and carbon costs.

Indicators such as EBITDA and market benchmarks can inform the margin but should not be treated as strict determinants. A consistent percentage-based margin ensures it scales proportionately with the total cost stack, supporting regulatory certainty and efficient retail operations.

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

We do not consider a lower small business margin appropriate under the proposed reforms. There is clear, quantitative evidence that small business customers present a higher bad debt risk than residential customers, both as a percentage of revenue and in dollar terms per customer.

Maintaining the small business margin as the percentage of the total cost stack ensures it reflects the higher inherent risk and cost of serving small businesses. Any adjustment should be evidence-based and reflect actual (rather than assumed) differences in cost and risk.

Question 20: How should the retail margin be apportioned across the fixed and variable cost components of the DMO? Question 21: What, if any, alternative methodologies should we consider in reassessing these retail margins

See response to Question 18.