03 November 2023

Gavin Fox
A/General Manager, Market Performance
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Sent via email to: DMO@aer.gov.au

Re: Default Market Offer Prices 2024-2025

I refer to your Default market offer prices 2024-25 Issues paper (DMO 6) and provide thanks to the Australian Energy Regulator (AER) for the opportunity to provide a submission.

1st Energy is a non-integrated, second-tier electricity and gas retailer for residential and SME customers. Founded in April 2015, 1st Energy operates throughout the eastern states of Australia including New South Wales, Queensland, South Australia, Tasmania, and Victoria.

The cost-of-living crisis continues to be front and centre for many Australians and we recognise consumers are looking for price relief. The AER is faced with the task of setting a DMO 6 which strikes the right balance in meeting the policy objectives. We are concerned that the DMO will move away from its core objective of protecting standing offer customers from unjustifiably high prices and it will be artificially skewed to provide consumers protection from the actual costs to operate in the retail market. This is likely to result in a further reduction of available market offers and competition will be stymied.

The increasing cost of household bills from the rising stress on Australia's energy market can be appropriately supported via targeted assistance measures directed at vulnerable households and continuation of relief packages such as the Energy Bill Relief Fund.

The AER have posed a number of questions on the DMO 6 and we provide our responses in Appendix A.

For any queries regarding this response, please contact Aneta Graham, Head of Regulatory and Compliance, aneta.graham@1stenergy.com.au 03 8397 7147.

Yours sincerely

Liam Foden
Managing Director
1st Energy Pty Ltd

Appendix A

Wholesale costs

Question 1: What approach should we take towards estimating load profiles? Should we retain profiles based on the NSLP and CLP, create blended profiles using the NSLP/CLP and advanced meter data, or take another approach towards estimating load profiles? Which is most reflective of a reasonable retailer's approach?

We strongly support the use of advanced meter data. The uptake of advanced meters opens new possibilities for load profiling. With advanced meter data, standard customer class load profiles can be updated, customers can be clustered into similarly behaving groups, or individual load profiles can be created. In our view advanced meter data-based load profiles provided superior estimation accuracy.

32% of 1st Energy's New South Wales, Queensland and South Australia customers have advanced meters and in our experience we have observed a peakier load profile compared to the NSLP. The peakiness of the load shape is increasing the costs of hedging as net load dips significantly during the day and a blended profile is necessary.

As the AER have stated solar PV system uptake is over 30% and impacting on the times customers consume from the electricity grid. We note not all solar PV systems have an advanced meter and this should also be considered when estimating the load profile.

Question 2: Is the lack of transparency of AEMO's advanced meter data a major issue for stakeholders? What information could we provide stakeholders to address issues with transparency of data?

AEMO publish net system load profiles and total system load but there is a gap between this and identifying small customer load relevant to assessing load profiles at a broader level beyond our own customer base. We would like to see this data published.

Question 3: How should we consider the impact of solar PV exports in advanced meter data when estimating load profiles?

Solar PV is adding to the peakiness as continually increasing solar generation (in particular between 10am to 3pm) is causing load to dip and spot prices to often shift negative. This can create spot price exposure to retailers because when net load and spot prices go negative and a retailer doesn't have a commercial and industrial portfolio to offset this excess solar they're exposed to spot price outcomes. The costs of negative spot price and negative load should be incorporated into the methodology until AEMO's forecast improvement of reliability risks is evident.

Question 4: Should the AER determine separate load profiles for residential and small business customers? Is this reflective of a prudent retailer's approach?

We do not believe that separate load profiles are necessary as we take a combined portfolio approach to hedging.

Question 5: Should the AER have a singular profile for the entire NSW region instead of individual load profiles based on distribution zone? Is this reflective of a reasonable retailer's approach?

A singular profile generally reflects industries current approach to hedging in New South Wales and we believe this is reflective of a reasonable retailer's approach.

Question 6: What additional data should we consider when assessing contract pricing for DMO 6, given the lack of liquidity in South Australia remains?

We would like to see greater liquidity on the ASX in relation to South Australia. When considering the use of additional data such as OTC contract information it is important to contemplate and differentiate between intercompany hedges and transfer pricing which may not reflect true wholesale costs.

Question 7: In the absence of sufficient exchange traded South Australian contract data, what other methodologies could the AER investigate to determine the wholesale cost in South Australia?
Would consideration of a retailer holding Victorian futures contracts with SRAs be reflective of the practice of a reasonable retailer? How would we model this?

We are strongly opposed to the use of SRA's for this purpose. They are not a firm contract and increase the risk profile of a retailer and would require significant amounts of capital to manage.

Question 8: Should we consider any other changes to the wholesale cost methodology in light of a changing wholesale market?

In general, we agree with a 'market based' forecast approach and continuation with the current wholesale methodology with minor changes appropriate for the DMO 6. Any widescale changes would require more than a few months for a retailer to implement, subject to their business model and if they broadly follow the wholesale methodology. It is important that wholesales costs are calculated based on real world hedging strategies and we are of the view an 18 to 24 month build best meets these objectives.

Consideration could be given to incorporate cost allowance for retailers where spot prices are negative combined with negative net load. Our observations are a negative price combined with a negative load becomes an unhedged exposure to retailers which increases our risk profile. There is a challenge in covering off the peakiness of the load and the cost of the coverage is increasing.

It is also appropriate to reconsider the shift to the 75th percentile estimate given the volatility of the wholesale market. We continue with the view that a 95th percentile hedged wholesale energy cost estimate remains appropriate and reflective of a prudent retailer. As industry foreshadowed it is apparent that the period of instability will continue and go on being intensified by international conflict.

We would also like unaccounted for energy (UFE) costs to be captured in relation to global settlements. Every retailer is now billed for the loss-adjusted metered electricity that is consumed by their customers within a given region and this has a cost impost that was previously not apparent.

Retail costs

Question 9: Do you consider these current methodologies used appropriate, and if not, what alternatives should be considered?

Our view is that a cost-stack methodology can work when the building blocks are sufficiently reflective of retailer costs.

One of the objectives of the DMO is to allow retailers to recover the efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention and its important that the current cost-stack retain these inputs whilst also allowing for the escalating costs of significant regulatory changes such as the Consumer Data Right and the Better Bills Guideline which have a material impact on our operational costs. If components such as CARC were to be removed this would have a critical impact on a retailer's ability to remain competitive and would reduce available market offers.

Advanced meters

Question 10: Is the method for cost recovery of advanced metering costs appropriate for DMO 6 and/or future DMO decisions? If not, what alternative methods should the AER investigate to recover the cost of advanced meters?
Question 11: Should the AER project advanced meter installations instead of using historic data in future DMO decisions?
Question 12: What operational or cash flow considerations should the AER consider in determining the cost recovery of advanced metering costs? How do these considerations differ between large and small retailers?

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Question 13: What operational and capital expenditure advanced metering costs should the AER include in the costs recovered by retailers? Should these costs be subject to independent audit or review?

Our preference is to move away from a look back view and to use future run rates ensuring costing for multi-phase, complex installations and regional travel costs are included. The advanced metering cost allowance could incorporate a blend reflective of the different metering installations factoring in the associated administrative burden.

Retail allowances

Question 14: Are there methodological changes that would allow us to better balance the objectives in the retail allowance?
Question 15: Should the retail allowance be a fixed dollar amount, and if so, why?
Question 16: Alternatively, should the retail allowance be cast as separate components of efficient margin (percentage based) and additional competition allowance? How would these be calculated?

We are supportive of maintaining the current approach of calculating the retail allowance as a percentage of the DMO price. The retail allowance needs to accommodate the ebbs and flows of the market, as prices contract retailers see their costs rise and fall accordingly; this is evidenced by retailers withdrawing from the market when the retail margins are inordinately constrained. The stated ACCC retailer margin of 2.5% does not promote a competitive market nor allow room for market volatility.

Risk profiles change with increasing in costs and higher bills; therefore, a percentage-based approach better reflects the retail allowance required by retailers under both high and low-price scenarios.

Question 17: What components are missing from the retail allowance and why?

Recognition of the impact of increased working capital costs due to rising interest rates and wholesale market volatility which has resulted in increased credit support costs.

Question 18: Should the retail allowance differ for residential and small business consumers? If so, that risk or cost factors drive this difference and how should this be calculated?

The retail allowance component should differ for residential and small business customers as they have a different risk capability and small businesses are better able to manage their risk; this is further compounded by the increased bad debt risk retailers must allocate for a small business customer.

Other DMO costs and considerations

Question 19: Should network costs be based on a blend of flat rate and time of use network tariffs? If so, how should this blend be calculated?

We are supportive of using the available network tariffs and the blend should be proportional to the uptake.

Question 20: Does our proposed approach to determining a broadly representative time of use pattern remain appropriate?

We are comfortable with the proposed approach continuing.

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