10 November 2023

Stephanie Jolly
General Manager, Market Performance
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Submitted by email: DMO@aer.gov.au

Dear Ms Jolly,

Default market offer prices 2023-24 – Issues Paper

Origin Energy Limited (Origin) welcomes the opportunity to provide comments on the Australian Energy Regulator's (AER) Default market offer (DMO) prices 2024-25 Issues Paper.

We note the DMO objective requires prices to be set at a level that allows retailers to recover efficient costs, while also facilitating competition, and ensuring that customers are protected from unreasonably high prices. It is within this context we have framed our discussion of the various matters raised in the Issues Paper.

Wholesale Energy Cost

Origin agrees it is prudent to periodically assess whether the wholesale energy cost (WEC) methodology remains appropriate. In this respect, we consider there are aspects of the methodology that should be addressed to ensure the estimated WEC for DMO 6 adequately reflects the costs likely to be incurred by a prudent retailer over the FY25 period.

We support the AER adopting a blended load profile based on a combination of net system load profile (NSLP), controlled load profile (CLP) and advanced meter data, with solar exports netted-off. This will better reflect a typical retailer's small customer load and therefore support a more accurate calculation of the cost of supplying energy to those customers.

While acknowledging the questions around liquidity in South Australia in determining hedging costs, the current reliance on ASX Energy trading data, benchmarked against over the counter (OTC) data where possible, is still the most appropriate approach. Should a material misalignment in ASX Energy / OTC trade prices be observed, ASX Energy daily settled prices for SA products could be utilised to inform SA hedging costs, noting there is a clear and transparent methodology for determining those prices.

The framework should also be updated to remove any subjectivity around the determination of the hedging strategy. This could be achieved by requiring ACIL Allen test the potential resilience of any strategy to different market outcomes (e.g. a material increase in spot prices) with a view to minimising risk, rather than simply adopting the least cost strategy based on modelled spot prices. Such an approach is likely to be more consistent with the anticipated behaviour of a prudent retailer.

In DMO 5, the spot price modelling against which the hedging strategy is tested also provided a relatively narrow distribution of average energy prices. The difference between the 5th and 95th percentile energy price modelled for Queensland, New South Wales and SA was $3.70/MWh, $4.30/MWh, and $4.70/MWh respectively. In comparison, the average annual energy price for Qld over the last 10 years based on spot market outcomes has ranged from $34/MWh to $122/MWh. This indicates the prices modelled do not reflect the level of variability typically observed in the National Electricity Market (NEM). To address this, it is important the modelling assesses a broader range of plausible scenarios that could

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materially impact wholesale spot prices, including variability in fuel costs (i.e. coal and gas) and high generator outage scenarios.

Retail Allowance

The Issues Paper states that the AER is contemplating its approach in setting the retail allowance and is requesting feedback on whether any changes are required. Origin recognises the challenge for the AER in setting a retail allowance that balances the objectives of providing a sufficient margin to promote competition and innovation, while also protecting customers from unreasonably high prices.

Implicit in any move away from the current approach is that the setting of the retail allowance undermines the meeting of this objective. However, this is not supported by the evidence, particularly as it relates to any suggestion that the allowance is being set at too high a level. Our assessment of key retail market indicators reveal that active customers are benefitting from lower prices and that retailers are not making excessive profits which strongly supports the case for maintain the current approach in deriving the retail allowance. Deviating from this, including through any lowering of the retail allowance will limit retailers' ability to discount, disincentivise new entry and ultimately undermine competition, which is not in the best interest of energy consumers.

Origin does not support the other options contemplated in the Issues Paper. This includes setting the retail allowance as a fixed dollar amount which would not account for any increased risk to retailers if there were an uplift in the components of the cost stack such as the wholesale energy cost. Similarly, any plans to split the retail allowance and explicitly derive a competition allowance by applying a percentage-based margin to retail operating costs (ROC) would result in a significant reduction compared to the current retail allowance. This would have a seriously detrimental impact on competition and incentives for new market entrants.

We also support the continued application of different target margins for residential and SME customers (10 and 15 percent respectively). Any variance in the AER's approach relative to other regulators is explained by the differences in the regulatory derogations applied as opposed to any explicit policy intent. The relatively modest EBITDA margins for SME customers is also not indicative of the retail allowance being too high.

Network Prices

Under the DMO Code, the AER is required to publish its annual DMO prices by 26 May each year. However, in a network revenue determination year (such as 2024), the AER will not receive proposed network prices until around 21 May. This timing makes its extremely challenging for the AER to assess and approve these prices for inclusion in the calculation of DMO 6.

We propose that the Draft Determination makes clear that in the absence of approved network prices the AER will use prices submitted by the networks in their annual pricing proposals for 2024-25. These prices represent the best information available in that they should reflect the recently approved revenues and demand forecasts from the AER's revenue determination.

If you wish to discuss any aspect of this submission further, please contact Sean Greenup (sean.greenup@originenergy.com.au) or Shaun Cole (shaun.cole@originenergy.com.au).

Yours Sincerely,

Steve Reid
General Manager, Regulatory Policy

1. Wholesale energy cost

[1] The Issues Paper identified two primary matters for consideration – the derivation of the customer load profile and approach to determining hedging costs in SA. We have addressed these matters in further detail below, but note it is crucial the AER also considers the approach to determining the hedging strategy and range of spot price modelling assumptions. In Origin's view, there is risk that under the current methodology the forecast WEC may not reflect the risk management practices of a prudent retailer; and modelled spot prices may not capture an adequate range of potential market outcomes that a retailer could be exposed to.

1.1 Load profile assumptions

[2] Given the increasing penetration of advanced meters, Origin considers it prudent to adopt a blended approach in the 2024-25 DMO, as this will provide a more accurate representation of load profiles. Specifically, we suggest the AER use a combination of NSLP, CLP and advanced meter data, with solar exports netted-off, to determine customer load profiles. Visibility of the process for determining the profile could be supported through publication of the data source, resultant load profile and any underlying assumptions. This will enable stakeholders to construct comparable profiles using their own data and allow for a high-level sensibility check.

[3] We note that the Queensland Competition Authority (QCA) used advanced meter data in combination with the relevant NSLPs and CLPs, to estimate wholesale energy costs in its recent regulated retail price determination. The QCA provided a description of the load profiles used and the associated data sources. In addition, the QCA published charts comparing the blended profile to the current NSLP profile.[1]

[4] In Origin's experience, load profiles can differ markedly between residential and small business customers necessitating individual hedging strategies. On this basis, we consider that constructing separate load profiles for residential and small business customers provides a more accurate reflection of wholesale energy costs.

[5] We also consider moving to a single load profile for the New South Wales region would be a regressive step in the event it further reduced the representation of solar PV customers in the NSLP of a given network area relative to the current approach.

Recommendation

- Smart meter data should be integrated into the NSLP for DMO 6 to ensure a more accurate representation of load profiles and consequently wholesale costs.

1.2 Wholesale spot price modelling

<u>Modelled spot prices should reflect a broader range of potential market outcomes</u>

[6] Spot price modelling is inherently challenging and contingent on iteratively running many statistical simulations with varying parameters. Under the current approach, permutations of 11 generator outage scenarios and 51 weather scenarios (with varying demand and renewable energy traces) are modelled to produce a total of 561 individual simulations. In doing so, the intent

[1] ACIL Allen, 'Estimated Energy Costs, final report, prepared for the QCA', May 2023, pg. 11-13.

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is to understand the cost of purchasing energy for a prudent retailer under differing market conditions.

[7] ACIL Allen noted in its Final Determination for DMO 5 that it is satisfied that the modelled spot prices cover the range of expected price outcomes in terms of annual averages and distributions.[2] However as we discuss below, when considering observed energy prices, Origin maintains that the plausible range of potential outcomes is not being fully captured.

[8] Market participants often conceptualise their exposure to the spot market in terms of sub $300/MWh (energy) and above $300/MWh (capacity) prices. This is particularly important in framing whether a hedge book contains sufficient volumes of $300/MWh strike price caps, as a retailer's exposure to spot prices above and below this point will be different.

[9] There is a broad range of factors that can impact the level of prices above and below $300/MWh. For example, fuel costs of generators can be a key determinant of energy costs, while capacity price outcomes are heavily influenced by supply scarcity and periods of high demand. It is difficult to assess the performance of the model in adequately capturing these factors based on the limited outputs provided. However, Origin's estimation of the average annual energy price in the DMO 5 modelling indicates there is a distinctly narrow spread across all simulations.[3] The difference between the 5th and 95th percentile energy price modelled for Qld, NSW and SA is $3.70/MWh, $4.30/MWh and $4.70/MWh respectively.[4]

[10] As a point of comparison, the average annual energy price for Qld over the last 10 years based on spot market outcomes has ranged from $34/MWh to $122/MWh.[5] Similarly, using ASX daily settlement data to determine an implied energy price shows the markets expectation of energy prices for FY25 have ranged from $45/MWh to $118/MWh since 2022.[6] This indicates the prices modelled do not reflect the level of variability typically observed in the NEM based on actual market outcomes.

[11] Given the above, it is important the modelling assesses a broader range of plausible scenarios that could materially impact NEM wholesale spot prices. We have outlined some key assumptions that should be considered in this respect.

- *Fuel price assumptions*: As we have previously noted, the narrow range of modelled spot price outcomes may in large part be attributable to fuel price assumptions being fixed across all simulations, which is an approach applied in previous WEC Determinations. This is consistent with ACIL Allen's observation that the variation in simulated hourly price duration curves for prices below $300/MWh in DMO 5 is less than observed over the past 10 years '*… due to a single assumption of fuel prices adopted in the simulations, whereas the historical data will reflect changes in fuel prices over time*.'[7]

  Given the strong correlation between movements in east coast gas market prices and NEM wholesale spot prices, taking a single view of fuel prices across all simulations is not a

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[2] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Draft Determination', 23 February 2023, pg. 74.
[3] The average energy price for each region has been derived by subtracting the '*Contribution of spot prices above $300 to annual average spot price ($/MWh)*' from the '*Annual regional time weighted spot price ($/MWh)*' from the following resource: ACIL Allen, 'Default market offer prices 2023-24 (Final Determination) – Summary results of market simulation', 25 May 2023.
[4] Ibid.
[5] Origin energy analysis of NEM spot prices.
[6] Origin energy analysis of ASX Energy settlement price data. The implied FY25 energy price equals the FY25 Base futures price minus the FY25 Cap futures price.
[7] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Final Determination', 23 May 2023, pg. 70.

prudent approach. Any variation between actual and assumed fuel prices could materially undermine the accuracy of the modelled energy prices, and by extension the WEC.

Determining a reasonable estimate of gas and coal prices for generation is also likely to be challenging. This is because there is significant uncertainty around the impact of the Gas Market Code on domestic gas prices, noting the code doesn't apply to gas procured through the facilitated gas markets that are often relied on for fuel during high demand periods, and exemptions from the $12/GJ price cap are available to producers. The coal cap is also due to expire on 30 June 2024 and therefore should not be applied for DMO 6.

- *Outage assumptions*: For a given weather scenario in the DMO 5 model, the 11 outage scenarios have only a minimal impact on the average annual energy prices – often about $1/MWh.[8] Given the events of winter 2022, it is clear thermal plant outages can have a material impact on wholesale spot market outcomes, particularly when coincident with low variable renewable energy (VRE) output. Testing high outage scenarios that materially impact the availability of generators in the model will therefore be important, particularly as thermal power stations approach end of life and the penetration of VRE increases.

- *Other assumptions*: In addition to the above, we recommend also testing high and low hydrology scenarios that can impact the level of output from hydro power stations, and delays in commissioning of new supply, which is particularly relevant given concerns around the pace of new asset development and connection.

Recommendation

- For FY2025, scenarios should be developed that allow the potential impact of the below factors on wholesale spot prices to be tested:
  - variable coal and gas prices;
  - high thermal generation outages;
  - low / high hydrology; and
  - delays in commissioning of new supply.

1.3 Hedging methodology

<u>Reliance on ASX trade data remains the most efficient approach to determining wholesale energy costs</u>

[12] The AER's Issues Paper notes there is a risk the ASX Energy trade data in SA may not be reflective of a prudent retailer's hedging costs given reduced liquidity and as a result, additional products may need to be accounted for to determine the WEC. Notwithstanding the observed reduction in trade volumes, our view is that the current approach remains appropriate.

[13] It is broadly accepted that futures trading data generally provides for the most accurate representation of a typical retailers' efficient costs. This is reflected in the Australian Energy Market Commission's (AEMC) advice on best practice retail pricing methodologies, and Frontier Economics' recent assessment of the DMO methodology.[9]

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[8] Origin energy analysis, as per footnote 3.
[9] AEMC, 'Advice on best practice retail price methodology – Final Report', 27 September 2013, pg. 39; Frontier Economics, 'Review of retail wholesale cost estimation methodology – Final Report for the AER', 14 April 2022, pg. 33.

[14] As noted by ACIL Allen, in periods where retailers are using other products such as OTC contracts more than previously to manage their risk, this does not necessarily justify a change in methodology.[10] To date there has been no evidence of OTC contract prices being systemically higher (or lower) than ASX Energy contract prices, with analysis undertaken by ACIL as part of DMO 5 demonstrating there was only a one to two per cent price differential between OTC and ASX Energy contracts that settled on the same day, a trend that has been observed for a number of years.[11] This likely reflects the fact that even where ASX Energy trading volumes are lower relative to previous periods, the transparent futures data is still a key point of reference for retailers and generators when pricing other products.

[15] Given the above, we recommend retaining the current reliance on ASX Energy trade data and continued benchmarking of those prices with broker data for swaps and caps, and other OTC contract data collected by the AER. If a material misalignment in trade prices is observed, this could indicate a need to consider alternate data sources to benchmark retailer hedging costs in SA. However, it would still be important to maintain an approach that uses publicly available data that retailers would typically rely on to inform their pricing of hedging products. The ASX Energy daily settled price for SA products could be utilised in this respect, given there is a clear and transparent methodology for determining the price that factors in executed trades, as well as bid / ask prices available in the market.

[16] We do not support approaches that would materially reduce the transparency of the price setting process and limit the extent to which industry and consumers could meaningfully interpret and engage with the analysis to test its validity, while also reducing the predictability / stability of the DMO. This would likely occur where a broader suite of bespoke products, the terms and conditions of which are more complex and not readily available in the public domain, is used to determine the WEC.

[17] A decision to incorporate a broader suite of products would also be predicated on the assumption that they are: principally used to hedge retail load; typically available to all retailers; and able to be accurately reflected in the hedging methodology applied. Consistent with our response to the DMO 5 Issues Paper, there are several issues to consider in this respect.

- *Power purchase agreements (PPA)s*: ACIL has noted there are considerable difficulties in using the price of PPAs or the annualised historical cost of generation as a basis for estimating current hedging costs.[12] The value of PPAs from a hedging perspective is also inherently dependent on the level of output from the relevant resources, and smaller retailers may not be in a position to even use PPAs given the associated capital requirements and uncertainty around future load.

- *Weather derivatives*: These products can be highly specialised and include a range of bespoke terms and conditions (e.g. number of geographic reference points, event triggers, maximum duration or number of events within a period, cost thresholds before paying out, payout limits etc.). It would be difficult to standardise these products to derive an associated hedge cost for a typical retailer.

- *Inter-regional hedging*: Settlement residue distribution (SRD) units can be used by retailers in combination with contracts (e.g. baseload swaps) to support inter-regional hedging. However, the existence of transmission constraints and ensuing basis risk from price

[10] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Draft Determination', 23 February 2023, pg. 44-45.
[11] Ibid.
[12] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Final Determination', 23 May 2023, pg. 15.

separation between the interconnect regions, limits their effectiveness / firmness.[13] Accurately assessing the utility of these units in combination with Victorian ASX trade volumes to inform SA hedging costs would therefore be challenging, and increase the complexity of the current methodology.

[18] In a scenario where the inclusion of the above products resulted in a lower WEC estimate that is potentially not achievable by smaller retailers / new entrants, this could also be detrimental to retail market competition, as acknowledged by Frontier Economics.[14]

Recommendation(s)

- Hedging costs in SA should continue to be determined using ASX Energy trade data and benchmarked with broker data for swaps and caps, and other OTC contract data collected by the AER. If a material misalignment in trade prices is observed, ASX Energy daily settled prices for SA products could be utilised to inform SA hedging costs, noting there is a clear and transparent methodology for determining the price that factors in executed trades, as well as bid / ask prices available in the market.

Determining the hedging strategy

[19] In response to the DMO 5 Draft Determination, we raised a concern that the hedging strategy adopted did not sufficiently reflected that of a prudent retailer. In particular, we considered the high proportion of cap contracts and low volume of baseload swaps resulted in greater pool price exposure for the retailer and consequently a riskier portfolio when compared to the strategy used for DMO 4.

[20] Origin agrees with ACIL Allen's view that the hedging strategy should not necessarily remain static year on year, and should be influenced by the shape of load profiles and price outcomes.[15] However, there is still merit in expanding the principles guiding development of the hedging strategy to account for the potential resilience to different market outcomes, with the objective being to determine a strategy that also minimises potential earnings at risk (EaR) if modelled pool prices materially increase relative to the expected outcome. This is appropriate given that remaining solvent and minimising possible losses is the foundation of a retailer's risk management framework and a primary consideration in determining a viable hedging strategy.

Recommendation(s)

- Given the above factors, we consider the principles guiding ACIL's determination of the hedging strategy should be expanded going forward to account for the potential resilience of the strategy to different market outcomes, with the objective being to determine a strategy that also minimises potential EaR. This should be supported by:
  - modelling a broader range of wholesale spot price scenarios (as discussed in Section 1.2),
  - explicitly modelling the sensitivity of the WEC to an increase in pool prices given the assumed hedge position, to illustrate the likely losses a retailer would incur (and

[13] AEMC, 'Secondary trading of settlement residue distribution units – Rule Determination', 10 October 2017, pg. 22-23.
[14] Frontier Economics, 'Review of retail wholesale cost estimation methodology – Final Report for the AER', 14 April 2022, pg. 30.
[15] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Final Determination', 23 May 2023, pg. 46.

therefore the effectiveness of the hedging strategy) if a one-in-ten year and one-in-twenty-year increase in pool prices occurred.

Length of the book build

[21] We generally support the existing book build process which occurs over a two-to-three-year period and agree pricing stability is important for customers.

1.4 Compensation costs

[22] We agree known AEMO and AEMC compensation costs should be passed through the DMO wholesale component.

1.5 Use of the 75th percentile

[23] The AER is proposing to retain the use of the 75th percentile WEC estimate on the basis that this should enable retailers to recover their costs, while not resulting in an excessive allocation of risk for consumers. While we agree it is important to balance the allocation of risk between retailers and consumers, we remain of the view that it would be more prudent to utilise the 95th percentile given the inherent uncertainties associated with estimating the WEC.

[24] As reflected in the above discussion on the WEC, spot price modelling is inherently challenging and contingent on iteratively running many statistical simulations with varying parameters, including forced outage profiles, weather sensitive peak demand shapes / renewable output and expected fuel costs. There is a material risk in the current environment (i.e. a transitioning market with elevated levels of volatility) that modelled WEC estimates may not reflect the actual costs incurred by a prudent retailer during a DMO period. This is a key reason ACIL Allen has historically adopted the 95th percentile of the distribution of WECs as part of its modelling approach, which is also utilised by the QCA in setting regulated electricity prices in regional Queensland.[16] Any reduced certainty that may be associated with lower ASX Energy trading volumes in SA could also be alleviated by adopting the 95th percentile WEC, as previously highlighted by ACIL Allen.[17]

2. Retail Costs and Allowance

2.1 Retail Costs and Bad and Doubtful Debts

[25] Origin retains its support for the AER to use the cost data provide by retailers to the ACCC.

2.2 Retail Allowance

[26] The AER's retail allowance includes both an implied retail margin and a competition allowance. The margin is intended to provide a return that a retailer requires to attract sufficient capital to finance the ongoing operation of its business, including compensation for systematic risk. The

[16] ACIL Allen, 'Default Market Offer 2023-24 – Wholesale energy and environment cost estimates for DMO 5 Final Determination', 23 May 2023, pg. 18; ACIL Allen, 'Estimated Energy Costs - For use by the Queensland Competition Authority in its Final Determination of 2023-24 retail electricity tariffs', 24 May 2023, pg. 15
[17] ACIL Allen, 'Default Market Offer 2022-23 - Wholesale energy and environment cost estimates for DMO 4 Draft Determination', 23 February 2022, pg. 32.

purpose of the competition allowance is to promote and maintain both competition and innovation to allow efficient retailers with enough incentives to enter the market and compete for customers.

[27] The Issues Paper states that the AER is now contemplating its approach in setting the retail allowance and is requesting feedback on whether any changes are required, with three options put forward for consideration. These include – calculating the retail allowance as a percentage of the DMO price (status quo); designating a fixed dollar amount for the retail allowance; and separating the retail allowance into two components, i.e. a retail margin and competition allowance. We discuss the merits of each option in detail below.

Maintaining the Status quo – calculating the retail allowance as a percentage of the DMO

[28] Origin recognises the challenge for the AER in setting a retail allowance that balances the objectives of providing a sufficient margin to promote competition and innovation, while also protecting customers from unreasonably high prices.

[29] Implicit in any move away from the current approach is that the setting of the retail allowance undermines the meeting of this objective. However, as we discuss below this is not supported by the evidence, particularly as it relates to any suggestion that the allowance is being set at too high a level. It is important to avoid any conflation of the issues, in that recent higher DMO prices have been due to elevated wholesale costs given extreme market volatility, not because of any underlying issues with the retail allowance.

[30] A vital first step in deciding whether a change is required is an understanding of how the market is operating as it relates to some key retail sector indicators.

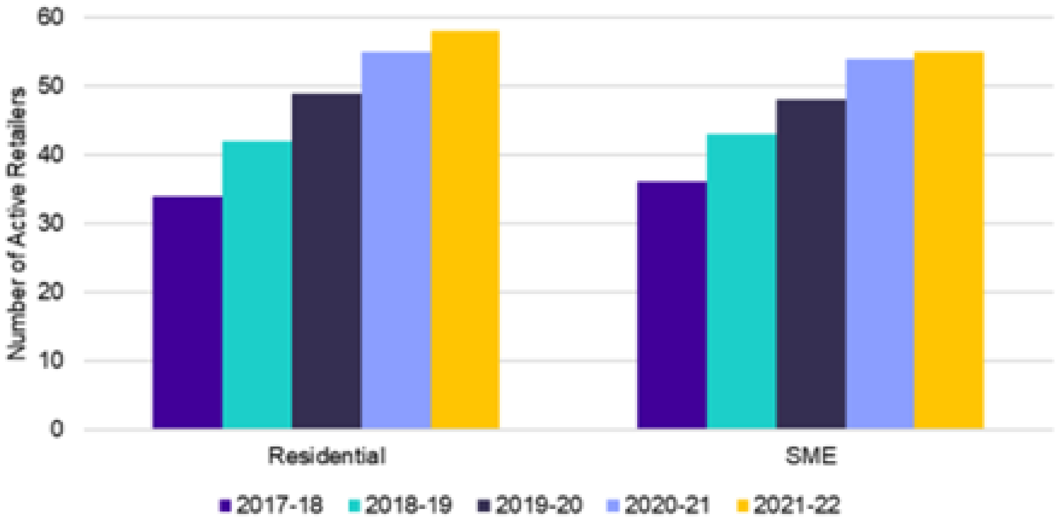
[31] To date, the primary metric regulators have pointed to when assessing the effectiveness of regulated prices in enabling competition is the spread of market offer discounts. These discount spreads are often used as a proxy for price-based competition. This is given the DMO (and specifically the retail allowance) is intended to provide retailers with an allowance above their efficient costs such that they can engage in price-based competition by making discounted market offers available to customers. A greater discount spread is taken to be indicative of a higher level of price-based competition in the market.

[32] However, the effectiveness of how the market has performed under the DMO cannot be fully understood by looking at discount spreads alone, and a range of competition metrics should be reviewed. These include the number and nature of market participants, market concentration, and the recent financial performance of retailers.

[33] As we discuss below, Origin's assessment of the above parameters indicates that active customers are benefiting from lower prices and that retailers are not making excess profits, which strongly supports the case for maintaining the current approach in deriving the retail allowance.

[34] As seen in Chart 1, the number of retailers actively servicing each customer type has increased each year since 2017–18. This steady growth in retailers infers that barriers to entry are currently sufficiently low.

Chart 1: Active electricity retailers in the NEM by customer type[18]



[35] For the increase in retailer market entry to support effective competition, these entrants must be actively competing for customers and winning market share.

[36] Chart 2 shows that since the DMO has been in place (2017-18 to 2021-22) there has been a progressive shift in market share away from the big 3 incumbent retailers to other participants.

[37] The Herfindahl-Hirschman Index (HHI) is a commonly accepted measure of concentration that considers the relative size distribution of the firms in a market. The higher the index value the greater the concentration, with the value of one representing market controlled by a single firm. The HHI in Chart 3 shows that since the introduction of the DMO market concentration has been progressively decreasing. Read together Charts 2 and 3 show that not only has there been an increase in new entrants, but these new entrants are winning significant market share from incumbent retailers.

[18] ACCC, 'Inquiry into the National Electricity market – November 2022 Report', 23 November 2022, pg. 70.

Chart 2: NEM-wide small customer market share for 2013-14, 2017-18 and 2021-22[19]

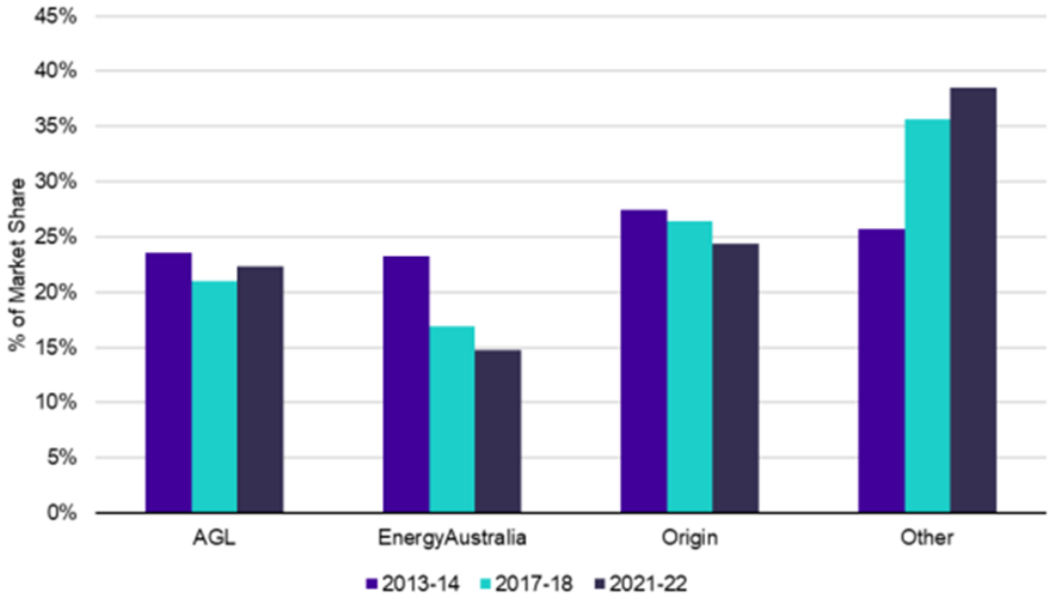
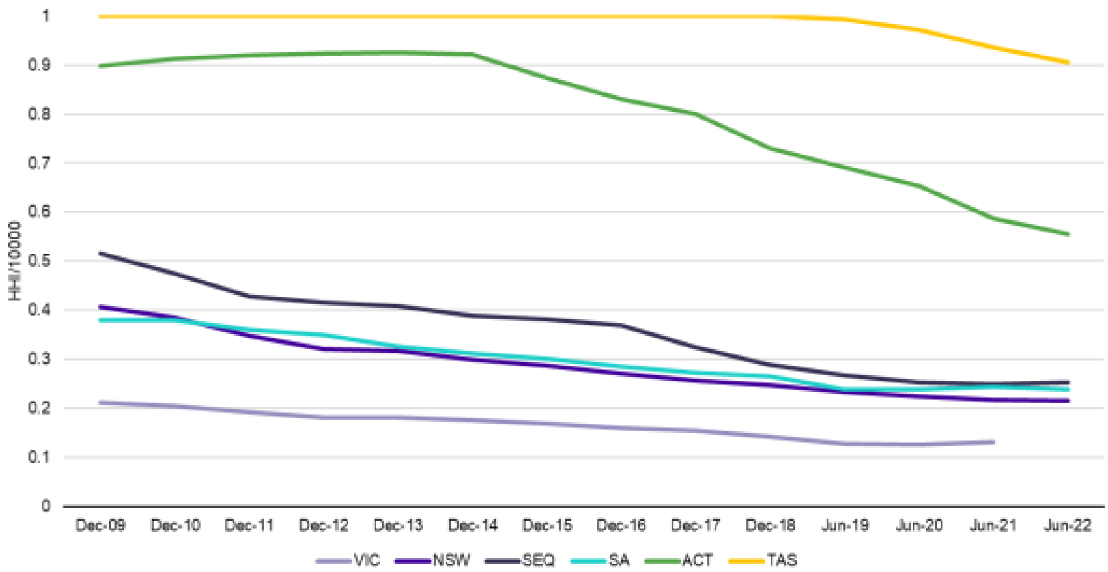


Chart 3: Herfindahl-Hirschman Index by region[20]



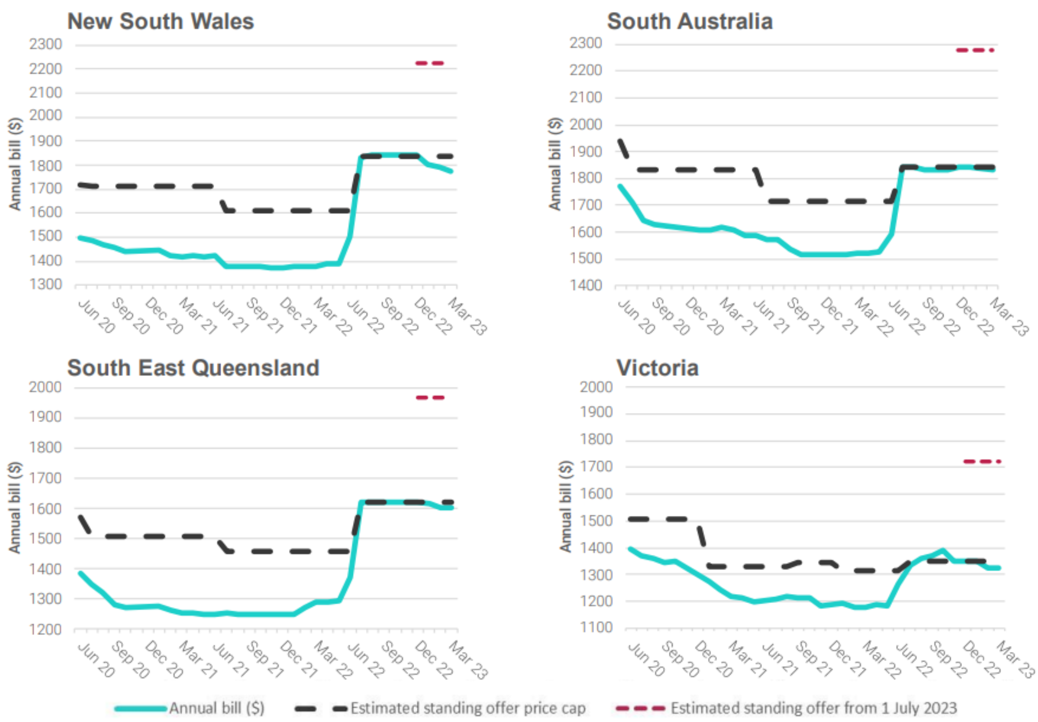
[38] This increased market activity should coincide with price competition. As the AER notes in its Issues Paper, in DMO 2 and DMO 3 there was evidence that the median and minimum market

[19] Ibid, pg. 68.
[20] Ibid.

offers were significantly discounted indicating that retailers were effectively competing and providing incentives for consumers to engage.[21]

[39] Additionally, as seen in Chart 4 the ACCC found that estimated median bills for customers on a market offer have been well below the standing offer or DMO prices, which is a sign of robust discounting activity. There was some convergence of market and standing offers at DMO 4, but this was primarily due to the stress in the retail sector given the lag in recovering the unexpected and unprecedented higher wholesale costs. As wholesale volatility has slowly reduced, discounting activity is starting to rebound.

Chart 4: Estimated median annual bills for residential customers on single rate market offer[22]



[40] Charts 1 to 4 show that since the introduction of the DMO there has been increased market activity and active competition in prices. If this discounting is sufficiently robust, it should also result in the competing away of excess margins. This is consistent with recent market outcomes.

[41] Chart 5 shows that average retail EBITDA margins across the NEM since 2016-17 have dropped 75 per cent in real terms from $145 per residential customer to $35 in 2021–22.

[42] Similarly Chart 6 indicates that retail margins for small business (SME) customers have declined at a similar level over the same period and even more drastically from 2020-21 to 2021–22.

[21] AER, 'Default market offer prices 2024-25 Issues paper', October 2023, pg.4.
[22] ACCC, 'Inquiry into the National Electricity market – June 2023 Report', 2 June 2023, pg. 18.

Chart 5: Average retail margins as EBITDA for residential customers across the NEM[23]

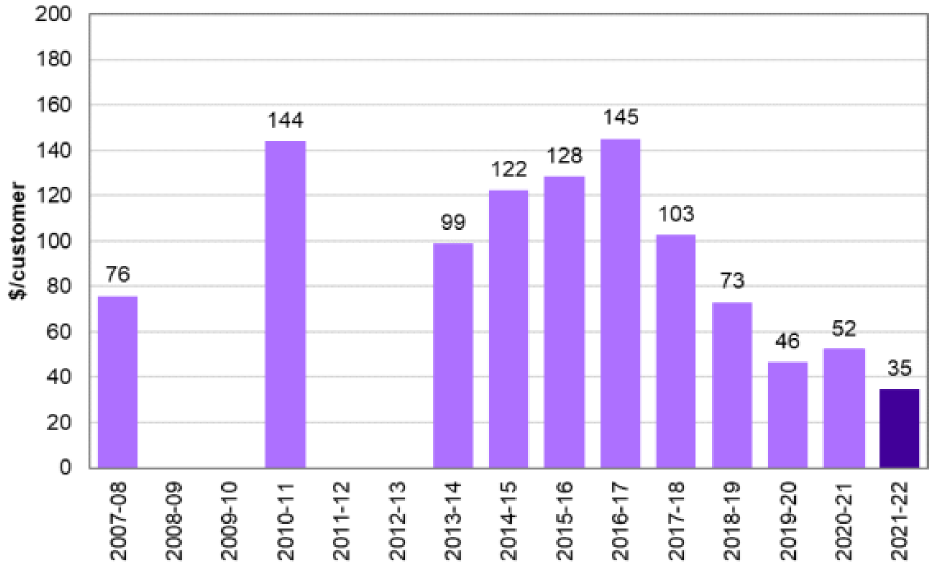
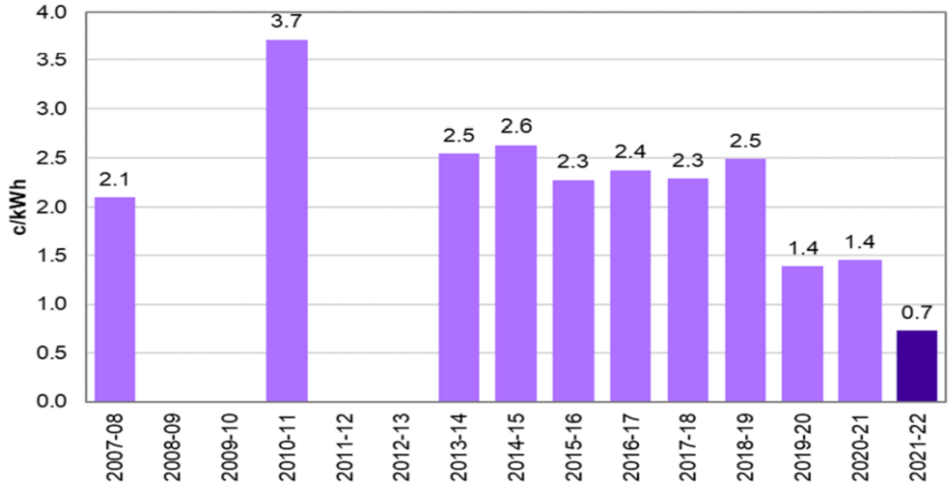


Chart 6: Average retail margins as EBITDA per electricity usage for SME customers across the NEM[24]



[43] The above discussion indicates that retailer activity is sufficiently high, resulting in robust price competition with modest retail profitability which is effectively being competed away. This reinforces that the DMO (including the retail allowance) is enabling customers to benefit from lower prices while ensuring retailers are not making excess profits. A move away from the current approach, including through any lowering of the retail allowance will limit retailers' ability to discount, disincentivise new entry and ultimately undermine competition, which is not in the best interest of energy consumers.

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[23] Ibid, pg. 73.
[24] Ibid, pg. 112.

An adequate retail allowance is also required for market innovation

[44] In its November 2022 Inquiry into the NEM Report, the ACCC noted that the development of new products and services is an important outcome of, and reflection of, competition in the market. It stated that the ability to choose from a range of different products benefits consumers as they can select a product that best suits their preferences and circumstances. The ACCC went on to state that high levels of innovation and product differentiation are signs of a competitive market.[25]

[45] We are seeing the prevalence of non-price products and services such as green products, products for EV owners, flexible demand-based products, optimisation services for premises with solar and battery, and bespoke support for small businesses gaining momentum. Many of these emerging products will assist in enabling the transition to net zero, provide consumers with greater autonomy in how they engage with the energy market.

[46] The retail allowance needs to take into consideration the need for headroom for retailers to be able to innovate and develop these products. More broadly there needs to be consideration in terms of the attractiveness of the sector to investment from other organisations outside of energy retailing. For example, from software providers to build new energy specific platforms and to organisations looking at non-commodity offerings retailed through the energy sector.

[47] Any move to limit the allowance runs the risk of stifling innovation.

Setting the retail allowance as a fixed dollar amount

[48] The notion of calculating the retail allowance as a fixed dollar amount was contemplated during DMO 5 and was based on concerns around the allowance being expressed as a percentage of the final DMO price, particularly in an environment of higher input costs. However, these higher input costs such as last year's unprecedented increase in the wholesale energy cost also expose retailers to added risk. As the allowance represents the revenue at-risk to the retailer, it is appropriate it is expressed as a percentage of the bill. Retaining a retail allowance which is linked to the quantum of the total cost, and set at an appropriate level, is important to meeting the DMO objectives.

[49] Overall, the risks and costs of being a retailer in the NEM have increased in recent times, as evidenced by the nine retailers that have ceased actively servicing the market since March 2022. Some of the key cost stack elements are increasing and becoming harder to anticipate, which also adds to retailer risks. Many of these are non-diversifiable (i.e. systematic or market risk) and relate to market volatility and uncertainty. The rationale for considering non-diversifiable risk in the retail allowance is articulated by SFG Consulting in their previous work for IPART, which noted 'the retail margin [allowance] must be sufficient to provide reasonable compensation for the potential variation in response to various economic conditions. It is positively related to the variability of revenue in association with economic circumstances.[26]

[50] In addition, the retail allowance component of the DMO acts as a safety net for retailers. It provides a margin for retailers which can be used to absorb some additional costs as they arise due to inconsistencies between the DMO and actual costs faced by retailers through the year. This is particularly important given the risk other DMO cost stack components may underestimate actual costs faced by some or all retailers – an inevitable risk given the retailer pool is diverse, and

[25] Ibid, pg. 70.
[26] SFG Consulting, 'Estimation of the regulated profit margin for electricity retailers in New South Wales (Methodology and assumptions)', 14 August 2009, pg. 7.

market dynamics and costs cannot be fully anticipated over the 12-month review cycle of the DMO.

[51] The allowance should encourage competition and consumer engagement. The intent is that retailers can offer discounts off the DMO and compete on price – ultimately leading to savings for consumers who switch to market offers and therefore an incentive for consumers to engage in the market. Retailers can only effectively compete when they have room to manage discounting, be creative in how they engage customers, and provide high quality services to attract customers.

[52] If the aggregated retail allowance is set at a fixed dollar amount in a scenario where the current level is used as the starting point, the allowance is effectively diminished when the total DMO rises. Without a sufficient allowance to create headroom and enable lower-priced offerings, there is a real risk of consumers largely converging onto the DMO across all retailers, with subsequent higher-than-DMO increases in retail prices and bills for those customers previously on discounted offers.

[53] We believe setting the retail allowance as a fixed dollar amount would create a disconnect between the costs of a retailer and risk-based returns. Failure to set the allowance appropriately would diminish the attractiveness of the industry for prospective new entrants, lessen competition in price discounting and have a chilling effect on investment in innovation.

Separating the allowance into a percentage-based margin and a fixed competition allowance

[54] If the AER decides to disaggregate the retail allowance, our view is that could only reasonably be achieved by continuing to express both the retail margin and the competition allowance as a percentage of the cost stack.

[55] If the AER were to apply a percentage-based margin to the retail operating costs (ROC) to derive the competition allowance, this would result in a significant reduction compared to the current retail allowance. This is because of the relative size of the ROC to the cost stack. For example, applying a 5 per cent competition allowance to the ROC for the Ausgrid region would result in an allowance of about $11 compared to the current implied competition allowance of about $73 (i.e. 5 per cent on the cost stack).[27] We believe this would have a seriously detrimental impact on competition and incentives for new market entrants.

[56] If the AER were to apply a retail margin to the cost stack and a fixed dollar competition allowance, as stated in the above section, this would create the risk that if the DMO increased, the competition allowance would decrease in relative terms.

[57] We believe we have shown that retailers are prepared to price discount at the current level and customers are incentivised and prepared to switch at these levels. A reduction in the competition allowance inferred by this approach would have a negative impact on the discounts offered by retailers and would likely result in a decline in customer switching activity.

Recommendation(s)

- The AER maintain the current approach in setting the retail allowance as a percentage of the DMO price which is supported by a robust level of competition as indicated by discounting, increased new entry, lower market concentration, and no evidence of excess retailer profits.

[27] Origin energy analysis.

2.3 Differences in residential and small business retail allowances

[58] Analysis of underlying retailer costs in the AER's DMO 4 decision found that the implicit retail allowances present (which were based on the indexation method) were on aggregate approximately 10 per cent and 15 per cent of DMO prices for residential and SME customers respectively. These allowances formed the basis of the retail allowance and glide path in subsequent decisions.

[59] The AER has highlighted that its approach of adopting a different margin for residential and SME customers differs to other regulators that apply a consistent margin. We believe this is explained by the differences between the regulatory derogations applied to other regulators and the AER, as opposed to any explicit policy intent.

[60] In both the IPART[28] and QCA[29] regulated retail price decisions, residential and SME customers were defined as small customers. As a result, there was no differentiation in the retail allowance between these two customer types.

[61] Notwithstanding, the QCA did note that serving customers on small business tariffs carries higher retail costs than serving residential customers, on average. The QCA considered possible reasons for this were that residential and business customers had different risk profiles and as a result, retailers may require a higher return on their SME customers.[30]

[62] Unlike IPART and the QCA, the AER is required to make different determinations for each customer type in each of the electricity distribution regions. This allows discretion for the AER to ensure the reference price for a consumer type is generally reflective of the annual cost of supply for that customer.[31] We believe this is a key reason that explains the difference between the AER and other regulatory decisions (i.e. other regulators were required to apply the same margin to residential and SME customers because they both fell under the definition of small customer).

Recommendation(s)

- The AER maintain the current approach of applying the different target margins of 10 per cent to residential customers and 15 per cent to SME customers. Differences in the AER's approach to other regulators is explained by the differences in the regulatory derogations applied as opposed to any explicit policy intent.

2.3 Metering costs

[63] The AER derives its advanced metering cost allowance as the annual cost of a smart meter (net of up-front and distributor metering charges), divided by the proportion of customers with a smart meter in each jurisdiction. The calculation is based on historic smart meter installations, resulting in a one-year time lag in metering costs reimbursement for retailers.

[64] Origin previously noted that, as retailers proactively install greater numbers of meters and with the AEMC's proposed mandatory rollout, significantly more meters are expected to be installed

[28] IPART, Regulated electricity retail tariffs and charges for small customers 2007 to 2010, Electricity - Draft Report and Draft Determination April 2007 p.22.
[29] QCA, Regulated retail electricity prices for 2021–22 – Final Determination, June 2012, p.19 and National Energy Retail Law (Queensland), section5(3).
[30] QCA, Final determination, Regulated retail electricity prices for 2016–17, May 2016, p. 29.
[31] Department of the Environment and Energy, Public Consultation Paper Competition and Consumer Legislation Amendment (Electricity Retail) Regulations 2019, 22 October 2019, pp. 4-5.

each year. Given the lag in reimbursement, the annual costs incurred by retailers will potentially be significantly higher than the allowance. While in subsequent years the allowance will capture the increasing number of installations, the one-year lag results in financial exposure for retailers.

[65] We note that the DMO legislative framework does not provide a true-up mechanisms, meaning there is no facility to adjust future allowances for the difference between allowed and actual costs incurred. While the financial shortfall could be addressed by using forecast rather than historic costs, we appreciate the risks associated with the use of forecast data. In particular, the potential consumer cost impost in the case of over-forecasting and the inability to adjust future allowances to account for forecasting error. On this basis, we do not consider the use of forecast advanced metering costs appropriate at this time.

[66] As part of the accelerating the deployment of smart meters Rule change request, networks will need to develop approved legacy meter retirement plans (LRMPs) for retailers and metering parties. The LRMPs will be required to include a schedule of meters to be retired and replaced each year from 1 July 2025 to 30 June 2030. The Rule change will also require retailers to provide the AER with annual performance reports detailing compliance with the LRMP annual targets.

[67] The annual replacement schedules produced as part of the approved LRMPs will provide a robust estimate of future installations (and associated costs) from 1 July 2025. In our previous submission we argued that a working capital allowance should apply for differences between the AER's estimated allowance and actual costs. Given the AEMC's progress on the metering reforms and the fact that future metering forecasts will be supported by a performance monitoring regime, we consider the LRMP estimates should be used to determine the advanced metering allowance from 1 July 2025, rather than continuing to rely on historic data.

[68] In our submission to DMO 5 Draft Determination we also highlighted the issues associated with the AER's decision to subtract up-front/one off advanced meter costs from the DMO advanced metering allowance. We noted that those retailers that rely on an annual allowance will not be able to fully recover their costs because their actual costs have been reduced by the amount of upfront fees charged by other retailers. Further, those retailers that have applied up-front fees will continue to recover metering charges through the metering allowance in the DMO.

[69] Subtracting up-front costs prevents the recovery of legitimate metering costs for those retailers such as Origin who do not apply up-front charges and incentivises other retailers to charge up-front fees.

[70] The AEMC's final report (and subsequent Rule change request) proposes a prohibition on retailers charging upfront costs for meter replacements under the acceleration deployment program from 1 July 2025. Origin supports the prohibition on up-front fees. We also consider the AER should align its position with the AEMC for DMO 6 and not subtract up-front charges.

Recommendation(s)

- The AER adopt LRMP estimates to determine the advanced metering allowance from 1 July 2025, rather than continuing to rely on historic data. We also recommend that the AER do not include upfront fees in its calculation of metering costs consistent with the AEMC position.

3. Network costs

[71] Under the DMO Code, the AER is required to publish its annual DMO prices by 26 May each year. However, in a network revenue determination year, the AER will not receive proposed network prices until around 21 May. This timing makes its extremely challenging for the AER to assess and approve these prices for inclusion in the calculation of the DMO.

[72] This DMO coincides with a network revenue determination in NSW.

[73] The last time the AER did not have available approved network prices was for DMO 2. In that decision the AER used what it deemed as the best available information to make a network allowance in the DMO. For networks within a network regulatory control period, the AER used the indicative network tariffs from the last available annual pricing proposals. For networks undergoing a network revenue reset, the AER used the final revenue determination changes in revenue.

[74] However, there was a significant difference between the information relied upon by the AER and the final approved network tariffs. As a result, retailers incurred a significant under-recovery of their network costs.

[75] Since the DMO 2 decision, the Federal Government amended the DMO Code to extend the publication date for the DMO from 1 May to 26 May to provide the AER with additional time to incorporate approved network prices in its DMO calculation, and still enough time for retailers to model and publish retail prices before 1 July.

[76] As a result of this change in timing and improvements in its processes, the AER has stated that it is likely it will have approved, or at least received the distribution network service providers' (DNSP) proposed network tariffs in time for the DMO final determination.

[77] Regardless, while the AER is likely to receive proposed network prices ahead of its DMO decision, the timing is still extremely tight for the AER to both assess and approve these prices for inclusion in the DMO. Furthermore, if the AER considers the pricing proposals are deficient, a network has 10 business days to resubmit corrected prices, well past the DMO date.

[78] It is vital the AER declares what network price estimates it will use if it has not approved network tariffs for use in the final DMO calculation. We propose that the Draft Determination makes clear that in the absence of approved network prices the AER will use prices submitted by the networks in their annual pricing proposals for 2024-25.

[79] These prices represent the best information available in that they should reflect the recently approved revenues and demand forecasts from the AER's revenue determination.

Recommendation

- We support the use of final approved network prices in the calculation of DMO 6. Where this is not possible, the AER should use the network tariffs contained in the network pricing proposals submitted for approval by 21 May 2024.

4. Environmental costs

[80] Origin supports the current market-based approach to determining environmental costs.