5 August 2024

Mr Joe Dimasi
Tasmanian Economic Regulator
GPO Box 770
HOBART TAS 7001

By email: *office@economicregulator.tas.gov.au*

Dear Mr Dimasi

Review of the Approach to Regulatory Retail Electricity Prices Draft Methodology Paper

Thank you for the opportunity to provide comment on the Review of the Approach to Regulatory Retail Electricity Prices Draft Methodology Paper (Draft Methodology Paper).

The expiry of the 2022 Standing Offer Price Determination (2022 Determination) on 1 July 2025 comes at a time where cost of living pressures are prominent across all elements of residential and small business spending. As it prepares for the 2025 Standing Offer Price Determination (2025 Determination), Aurora Energy is acutely aware of these pressures and considers its role in supporting customers to manage their electricity costs a critical one for the broader Tasmanian community.

Conversely, there are pressures on all National Electricity Market (NEM) retailers through broader energy supply chain costs with recent regulatory periods reflecting high volatility in wholesale markets and rising network costs. Aurora Energy manages these risks for customers, yet, it represents only twelve per cent of the retail price stack.

Whilst increases within the cost stack may be unwelcomed by both Aurora Energy and its customers, it is vitally important to its sustainability that it is enabled to fully recover all elements of the supply chain that are intended to flow through to end-use retail prices. Doing so ensures Aurora Energy remains in a position to provide the required range of products and services to support Tasmanian electricity customers.

In annexure A to this letter is a detailed response to the Draft Methodology Paper.

Please contact Giles Whitehouse, Corporate Affairs Manager in regard to any questions or comments related to this submission.

Yours sincerely

Oliver Cousland
Company Secretary/General Counsel

ANNEXURE A – DETAILED RESPONSE TO DRAFT METHODOLOGY PAPER

1. Competition Context

Aurora Energy is placed in a challenging position as the sole Regulated Offer Retailer in Tasmania. Its cost, retail margin, unit prices and tariff strategy for the near entirety of its customer base are examined publicly and shared with all stakeholders, including its competitors. By simply being the Regulated Offer Retailer, Aurora Energy is at a competitive disadvantage. No other retailer operating in Tasmania is subject to price regulation.

The Regulated Tariff Schedule in itself is a limitation on Aurora Energy's ability to manage its tariffs, in particular, the historical and ongoing lack of cost reflectivity. This will be addressed as Aurora Energy develops its Retail Regulated Tariff Strategy for the 2025 Determination period.

In this context, it is critical that the Regulator acknowledges the growth and threat of active competition when assessing both Aurora Energy costs and its tariff strategy. Aurora Energy has been in a competitive retail market for the entirety of its regulated customer base since 1 July 2014. Whilst competition was initially inactive, in the past five years it has demonstrably escalated and continues to do so.

Regarding specific competition related methodology in the 2025 Determination, Aurora Energy will not be seeking an explicit 'Customer Acquisition and Retention Cost' (CARC) allowance. This decision is in no way an acknowledgement of the lack of competitive market pressure, rather, CARC is considered a blunt and opaque measure. Instead, Aurora Energy will demonstrate in its Preliminary Submission, due 15 October, the impact of competition on both its Retail Margin and Cost to Serve.

To this end, where necessary, Aurora Energy will request elements of its proposals throughout the price investigation process to remain confidential.

2. Length of Period

Aurora Energy recommends the Regulator adopt a four-year term for the 2025 Determination.

Aurora Energy requests the Regulator consider a longer period for the 2025 Determination as opposed to the standard three-year term. There is a material level of costs involved in preparing for and undergoing a price investigation for a Standing Offer Determination, with these in excess of $200K in regulatory fees let alone internal Aurora Energy resources committed to deliver submissions and engagement. Three years presents a constrained cycle noting that both Aurora Energy and the Regulator commence preparation for the next Determination whilst still in Period 2 of the current Determination.

A longer four-year period also allows for:

- greater certainty of cost allowances & prices for both customers and retailers; and,
- more time to focus on retail service outcomes with less time spent on regulatory matters.

Whilst there are some risks associated with a four-year term, such as increased divergence of costs from revenues (over/under recovery), these are present in all multi-year price determinations. However, Aurora Energy contends the benefit from longer term certainty and lower costs will provide adequate benefits to offset these risks.

3. Customer Numbers

Aurora Energy does not support the Regulator's approach of using five-year growth or decline rates to forecast Customer numbers.

The Regulator has proposed an alternative method of a five-year trend of movements in customer numbers of growth and decline. Aurora Energy does not consider a five-year trend period an appropriate, contemporary timeframe over which to determine a rate for forecasting due to the changing nature of the Tasmanian energy environment. Heightened competition, as demonstrated in recent months, will drive increased churn away from Aurora Energy over the next determination period, as well as potentially drive an increase in customers moving away from standard retail contracts and onto market retail contracts. A five-year trend will include multiple years of consistent customer numbers, or even customer growth due to the decommissioning of the old Aurora Pay As You Go market offer, which won't be a reliable indication of future customer number movements.

Further, Aurora Energy's retail tariff rates are not cost-reflective, hence, imprecise forecasting of customer numbers (and associated loads) at the tariff level can have material ramifications for Aurora Energy's ability to recover its Notional Maximum Revenue (NMR), which adds additional risk to its retail margin allowance. Internal churn between tariffs, driven by customers or decisions by the Australian Energy Regulator (AER) in relation to the Tasmanian network distribution business, can also have flow on implications to retail businesses that won't be factored into a forecast based purely on historical trends.

In the Draft Methodology Paper, the Regulator has also stated that the forecast of customer numbers could be more transparent. Aurora Energy notes that at every price reset it provides the Regulator with its full workings in regard to customer numbers and load by tariff. In its most recent price reset, Aurora Energy forecast its customer numbers based on the most recent twelve months of growth or decline by tariff, with further adjustments made to factor in the AER's decision to approve TasNetwork's proposal to make flat rate tariffs obsolete.

Aurora Energy's view is that a medium to long-range historical trend will not provide an accurate forecast of customer numbers, and that customer numbers and the associated load forecast should be determined by Aurora Energy based on contemporary trends, weather data and known or expected changes to the Tasmanian environment (including AER decisions in regard to TasNetworks). Further, inaccurate forecasting by tariff can have a perverse outcome on Aurora Energy's ability to fully recover its regulated retail margin due to the current lack of cost reflectivity in retail tariffs. Until such time as retail tariffs are re-balanced to reflect underlying costs, it is Aurora Energy's view that a simplistic, generalised approach to forecasting customer numbers and load should not be adopted.

4. Retail Margin

Aurora Energy supports a move to an 'expected returns' approach for the assessment of its Retail Margin.

Aurora Energy also supports the Regulator defining the period in which it will apply the expected returns approach.

As highlighted by the Regulator, the current 2022 Determination applies a dollar per customer margin approach. Aurora Energy has concerns with this methodology and the way it was applied, specifically:

- the setting of the Retail Margin on a dollar per customer basis was undertaken with a reference to (then) recent low wholesale cost periods and an overall lower cost stack.
- the inability of the fixed dollar per customer approach to reflect the volatility that is typical in the NEM.

Aurora Energy supports use of benchmarking as the underlying method to define a retail margin.

4.1 Use of Cost Stacks

It should be noted that whilst the Regulator allowed a 5.25 per cent Retail Margin for Aurora Energy in the 2022 Determination, the two (then) most recent cost stacks were adopted when converting this percentage into a *dollar per customer* allowance. This locked in a Retail Margin that was based on recent low wholesale cost periods that were preceded and succeeded by higher wholesale cost periods, which resulted in Aurora Energy receiving a dollar per customer Retail Margin that was materially lower than it otherwise would have been under a percentage-based approach, in effect, as low as 4.8 per cent margin.

In the event that the Regulator adopts a dollar per customer approach, whether at a 100 per cent or a lower level, the period in which the cost stacks are applied to the margin percentage should reflect a consistent view of the market across Determination periods in order to better reflect the average margin outcomes on a dollar per customer basis. To this end, the two-year period adopted by the Regulator in the previous Determination and this should be continued.

4.2 Move to an Expected Returns Approach

Aurora Energy considers the use of a full fixed dollar per customer margin inadequate for reflecting the risks it faces. A fixed dollar margin requires estimates of future costs which are highly uncertain. Converting a percentage margin into a dollar per customer value requires an estimate of future costs. High uncertainty over future costs means a greater risk of 'getting it wrong.' Keeping all else constant, this can result in windfall losses (if actual costs > forecast costs) or windfall gains (if actual costs < forecast costs). In practice, a full percentage-based approach is better suited to ensure the Retail Margin reflects the value of a cost stack at that point in time.

Aurora Energy has explored alternative methods to the dollar per customer approach in other jurisdictions, in particular, the Independent Competition and Regulatory Commission (ICRC) in the Australian Capital Territory adopted an 'Expected Returns' approach for the 2024-2027 Regulatory Period (as approved by the Regulator in his capacity as the ACT Regulator). This approach results in a balanced handling of risk and certainty of costs by setting a Retail Margin based on 50 per cent of the dollar per customer approach and 50 per cent of a percentage-based approach. This a hybrid approach appropriately compensates retailers for systematic risk as wholesale energy costs rise or fall.

The ICRC considered that this approach provides a more reasonable balance between providing a return to retailers and more stable prices for consumers than the current approach of using only a percentage margin.

Table 1 demonstrates that whilst the Expected Returns method with its blended margin approach is not the highest under each scenario, it provides a prudent middle ground compared to a fixed approach in years where costs increase, but also softens margin degradation compared to a percentage-based approach in years where costs decrease.

Table 1: Comparison of three Retail Margin methodologies under the current 5.25 per cent benchmark.

	Scenario (2024-25 $)					
Retail Margin Methodology	10% increase in Cost Stack			10% decrease in Cost Stack		
	$/customer	% of costs	Total Margin	$/customer	% of costs	Total Margin
Dollar Per Customer	$118	4.77%	$31,992,524	$118	5.83%	$31,992,524
Percentage-based	$127	5.25%	$34,265,141	$104	5.25%	$28,035,116
Expected Returns (blended)	$123	5.01%	$33,128,833	$111	5.54%	$30,013,820

4.3 Risks Faced by Aurora Energy

Regarding the range of risks faced by Aurora Energy, Regulator correctly identifies that quantifying the differences between the risks faced by retailers across jurisdictions is difficult. However, Aurora Energy contends that its risks are, overall, highly commensurate with those faced by other retailers. There is a perception that with a regulated wholesale instrument in place alongside the capacity for the contracting of large elements of the regulated load that Aurora Energy's risk is lower compared to other retailers. Yet, it is up to retailers to select their wholesale purchasing approach and the Regulator does not have a role in mandating, formally or informally, what this approach should be. In fact, the Regulator and the Tasmanian Government both seek Aurora Energy to apply efficiencies to its operation. In the context of the wholesale market this is primarily undertaken through the adoption of appropriate energy risk policies that may, or may not, drive actions outside an atypical understanding of wholesale market management.

Given the increasing nature of competition in the Tasmanian retail market, the pressure to bring efficiencies to Aurora Energy costs and the volatile nature of recent and future outputs of the NEM, the argument that Aurora Energy faces different risks compared to other retailers is indeed challenging to quantify.

4.4 Summary position

- Aurora Energy has identified that whilst there are perceived 'certainty' benefits from a dollar per customer Retail Margin, that this approach is equally open to returning inequitable outcomes as the previous methodology (percentage based).
- In the 2022 PD, Aurora Energy was provided with a benchmark methodology of 5.25 per cent, however, this was devalued when the cost stack it was assessed against was ultimately proven to be demonstrably lower than the cost stack in subsequent retail price periods.
- Aurora Energy has reviewed methodologies in other jurisdictions, in particular the ACT, and notes that an 'Expected Returns' approach (as approved recently by the Regulator) provides for a more robust, stable and predictable assessment of the return that can be expected to recover to be compensated for systematic risk.
- Use of the expected returns approach is also consistent with regulatory precedent (ICRC draft determination for the 2024-27 regulatory period).
- Under this approach, OTTER should retain its its current benchmarking approach as the initial first step in articulating the retail margin values.

5. Cost to Serve

Aurora Energy supports the Regulator's proposal to broadly retain the current approach to assessing and calculating the CTS from the 2022 Determination for the 2025 Determination.

Aurora Energy does not support the continuing use of the efficiency factor mechanism or removing the customer number adjustment mechanism.

Aurora Energy considers that at a minimum cloud-based software costs need to be considered as part of either CTS or Retail Margin although the CTS appears the most appropriate location.

Aurora Energy is supportive of the previous methods for setting the cost-to-serve using a bottom-up estimate of cost, with the use of benchmarking to Tier 2 retailers to verify these costs. Aurora Energy encourages the Regulator in setting a CTS method to ensure it sets a finding that considers and accounts for a wide range of sources.

5.1 Efficiency Factor

Aurora Energy is seeking to limit the extent that cost reductions are imposed on its operations, including the current efficiency factor which is not consistent with regulatory precedent or good regulatory practice in a competitive market.

Advice provided to Aurora Energy is that application of an efficiency factor is inconsistent with incentive regulation and good regulatory practice noting it becomes increasingly challenging to achieve efficiency improvements as a business gets closer to an efficiency frontier. Specifically, the OTTER rationale appears to include management induced efficiencies as well as exogenous efficiencies, which is inconsistent with regulatory practice, instead, it is typical to include only exogenous productivity improvements.

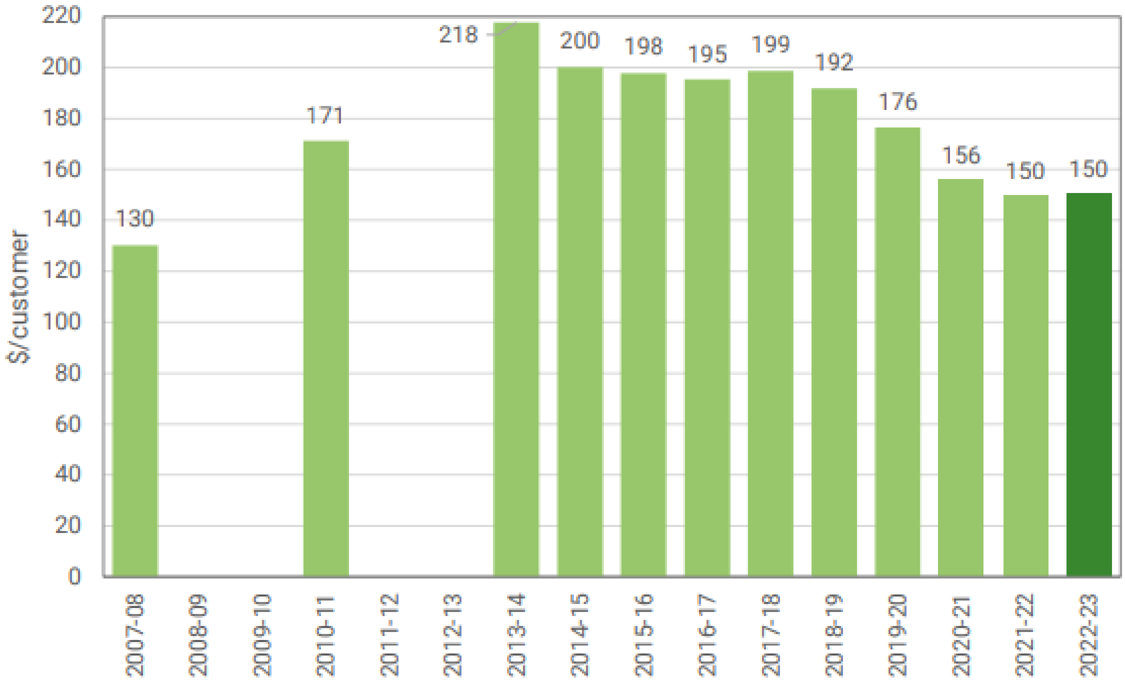
Aurora Energy acknowledges that recent financial years have included higher costs driven by a billing system migration, and therefore intends to submit a CTS build that is reflective not of recent years, but of a budgeted, efficient future state. Accordingly, it is Aurora Energy's view that further efficiency overlays are not required.

Further, the latest ACCC *Inquiry into the National Electricity Market Report*, the same annual report that was the reference used as the basis for determining the efficiency factor in the 2022 Determination, demonstrates that whilst an efficiency factor of 3.4 per cent per annum has been imposed on Aurora Energy in recent years, the average CTS in the National Electricity Market has remained flat from FY22 to FY23 (as indicated in Table 2). This demonstrates that:

- in real terms, Aurora Energy's CTS allowance has already been reduced at a rate higher than what is being observed in the market in recent years; and
- the high efficiency gains witnessed from FY18 to FY21 are no longer occurring, supporting the argument that businesses are getting closer to the efficiency frontier.

Table 2: Combined Tier 1 & Tier 2 Retailer Costs to Serve per the ACCC Inquiry into the National Electricity Market – December 2023

Retail and other costs per residential customer across the National Electricity Market, 2007–08 to 2022–23, real, excluding GST



Source: ACCC analysis of retailers' data.

It is further important to note that efficiency factors play a stronger role in systems that are supported by a monopoly provider. By comparison, Aurora Energy is operating in a fully contestable market where competition is markedly increasing. To this end, there is a natural driver on Aurora Energy to become more efficient in order to maintain a sustainable CTS and margin.

5.2 Removing the Adjustment Mechanism

In its Draft Methodology Paper, the Regulator proposed removing the adjustment mechanism that takes account of changes in customer numbers on the basis that Aurora Energy intends rebalancing its tariffs during the regulatory period. The Regulator noted that as a result of this rebalancing, it expects that Aurora Energy will be able to recover more of its fixed costs than was previously the case.

Aurora Energy seeks to clarify that the customer number adjustment mechanism was introduced by the Regulator in the 2022 Price Determination to account for the high proportion of fixed costs in Aurora Energy's cost base. This should not be confused with tariff re-balancing, which, whilst incorporates CTS, is more concerned with the imbalance between the materially higher fixed pass-through costs from Aurora Energy's suppliers (inc. Network costs) and the fixed retail tariff rates Aurora Energy can set to recover these costs from customers. The customer number adjustment mechanism is conceptually designed to allow Aurora Energy to include an allowance in the Notional Maximum Revenue (NMR) that reflects its allowed costs to serve. Tariff re-balancing is concerned with correcting the retail tariff rates so Aurora Energy can accurately recover all allowable costs in the NMR, including the 88 per cent of pass-through costs it isn't responsible for.

In its 2022 Standing Offer Electricity Price Investigation Draft Report, the Regulator stated:

Aurora Energy states that its costs are largely fixed in nature and do not vary materially with variable components such as the number of customers and customer load. In its Approach Paper, the Regulator acknowledged that if Aurora Energy's customer numbers change, Aurora Energy will have more or fewer customers from which to recover its fixed costs attributable to providing services under standard retail contracts. Therefore, the Regulator indicated it intended to allow the cost to serve allowance to vary in accordance with customer numbers by including a separate mechanism whereby the CTS is adjusted for the change (either upwards or downwards) in customers between periods.

As the Cost to Serve (CTS) per customer is calculated bottom-up using relatively flat customer numbers across future periods, the customer number adjustment mechanism is present to adjust the CTS as required to better reflect actual outcomes. For example, if Aurora Energy were to forecast less customers in its CTS build, the CTS allowance per customer would start higher. It's Aurora Energy's view that the customer number adjustment mechanism results in a more accurate CTS outcome than attempting to forecast four future years of customer numbers in a competitive and ever-changing environment.

Consistent with the 2022 determination period, Aurora Energy continues to argue that its costs are largely fixed in nature and do not vary materially with variable components such as the number of customers and customer load. If Aurora Energy's customer numbers change, Aurora Energy will have more or fewer customers from which to recover its fixed costs attributable to providing services under standard retail contracts. Aurora Energy's view is that nothing material has changed between determinations and the Regulator's decision in 2022 is still relevant, allowing the CTS per customer to vary in accordance with customer numbers by including a separate mechanism whereby the CTS is adjusted for the change in customers (either upwards or downwards) between periods.

Aurora Energy's interpretation is that the current formula for calculating the customer number adjustment does not fully achieve what it is intending to do and will present the Regulator with proposed amendments to the calculation. As the customer number adjustment mechanism was not required in the 2022 determination period because the 2 per cent threshold was not crossed, there has been no impact on previous price resets.

5.3 Treatment of Cloud Based Software Costs (Software as a Service)

Aurora Energy accounts for Software as a Service (Saas) costs in line with Australian Accounting Standards. Since the 2022 Price Determination, a number of traditional on-premise, capital systems have been replaced with SaaS arrangements that are required to be treated as operating costs. This has resulted in a reduction in depreciation costs and an increase to operating costs in recent years, which is consistent with industry trends.

Aurora Energy understands that the Regulator sets a retail margin based on Earnings Before Interest, Tax & Depreciation (EBITDA), and as a result, inherently includes an allowance for capital system investment and finance costs within the retail margin allowance. This is noted as distinct from other regulatory practices that enable recovery of SaaS through the CTS, as is done by the AER in network regulation.[1]

[1] AER, *Final Decision – Ausgrid distribution determination 2024-29, Attachment 6 Operating expenditure, p.16-17*

Costs associated with customising and configuring SaaS have never been included as part of Aurora Energy's bottom-up build of CTS, under the assumption that these costs replace the traditional capital costs that are allowed for in the EBITDA-benchmarked retail margin.

Should the Regulator wish to change the current approach of how system investment cost recoveries are distributed between retail margin and CTS, Aurora Energy will be supportive providing an appropriate amount for system investments is included in one of the regulatory allowances.

It is noted, however, that the inclusion of SaaS as operating expenditure and recovered through the CTS allowance would be in line with both accounting standards and available regulatory precedent in Australia such as with the AER. In this instance, its further important to note that retail margin benchmarking used in the 2022 Determination of 5.25 per cent in other jurisdictions doesn't include SaaS costs. As such, there should be no corresponding reduction in Aurora Energy retail margin if SaaS are to be classified as part of the CTS allowance.

5.4 Cost Allocation Manual

Aurora Energy notes it has already provided its cost allocation manual to the Regulator's office as per the outline described on page 33 of the Draft Methodology Paper.

5.5 Summary position

- Aurora Energy supports the Regulator's proposal to broadly retain the approach to assessing and calculating the CTS from the 2022 Determination for the 2025 Determination.
- Aurora Energy does not support the continued use of an efficiency factor. Specifically that by modelling a CTS based on an efficient, future state, further efficiency overlays are not required, particularly in a competitive market.
- The current customer number adjustment mechanism can produce a more accurate CTS outcome than attempting to forecast four future years of customer numbers in a competitive and ever-changing environment.
- SaaS will be most accurately recovered as operating expenditure through the CTS.

6. Wholesale Costs

Aurora Energy supports the retention of the current method of calculating the Wholesale Electricity Price (WEP).

In the Draft Methodology Paper the Regulator has assessed three options to calculate the WEP:

- Option 1: May calculation - the current method;
- Option 2: April calculation - using the last Tuesday in April as the cut-off point to calculate the WEP for the following year; and
- Option 3: No future price method - the current method except that both the LFS contract price and Absolute Minimum Capacity Offer volume for all weeks after the WEP calculation date are set to zero

The current WEP methodology best reflects the prudent hedging approach of a retailer, presents the least wholesale risks to Aurora Energy and, is consistent with the requirements of section 40 AB(3)(C) of the *Electricity Supply Industry Act 1995* (ESI Act) in ensuring that the WEP is related to the cost to Aurora Energy of hedging the small customer load profile.

Aurora Energy is concerned that the other two options assessed by the Regulator are less reflective of a prudent hedging approach that retailers would adopt to manage the wholesale risk relative to Option 1. Specifically, Aurora Energy contends that Options 2 and 3 would:

- increase wholesale risk to Aurora Energy in managing wholesale exposures for small customer load by bringing forward the contracting of future customer load;
- does not improve on existing methodology to reflect the cost of energy more accurately, or how a prudent retailer manages risk; and
- with regard to Option 3, by removing future volume in the methodology in the manner proposed by the Regulator, results in a WEP methodology that does not sufficiently set a WEP reflective of the volume weighted hedging costs reflective of the Tasmanian Small customer demand/load profile.

A more detailed assessment of each of the three options is provided below.

6.1 Option 1 – Current Approach

The current approach adopted by the Regulator to calculate the WEP for the 2022 Determination as set out in Clause 4.1 of the Regulator's standing offer price approval guideline is as follows:

1. *The Regulator will use the following method to calculate the wholesale electricity price (WEP) for each year:*
    a. *multiply the weekly regulated load following swap (LFS) price for each respective quarter of the relevant year by the weekly Absolute Minimum Capacity Offer Volume for that quarter for eight quarters preceding the start of each quarter of the relevant year;*

    b. *for those weeks where Hydro Tasmania is not required to offer regulated contracts, set the respective Absolute Minimum Capacity Offer Volumes to zero;*

    c. *for all future weeks for which there is no regulated LFS price at the time that the Regulator calculates the WEP, use the respective weekly point-in-time regulated LFS price for that quarter of the relevant year in the week that the Regulator calculates the WEP;*

    d. *divide the sum of the values calculated in accordance with Clause 4.1(1)(a) by the sum of the weekly Absolute Minimum Capacity Offer Volumes for the eight quarters preceding the start of each quarter of the relevant year.*

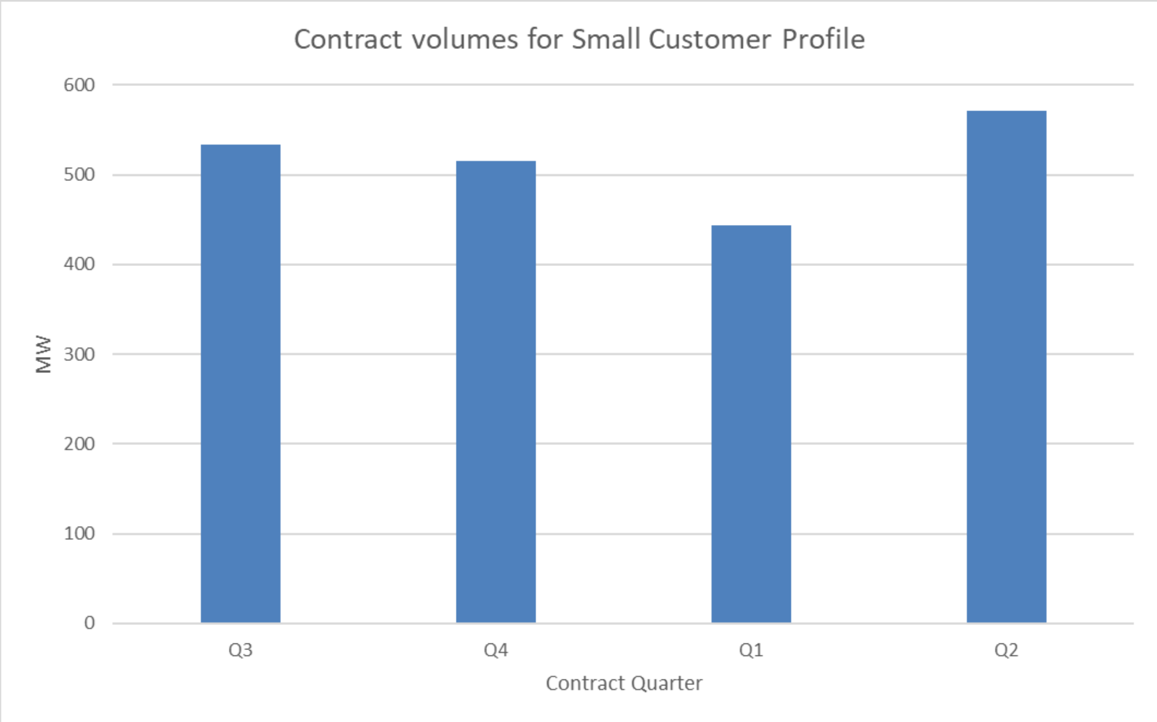
2. *The Regulator will provide the WEP, calculated in accordance with the method outlined in Clause 4.1(1) for the relevant period, to Aurora Energy, not less than seven days prior to 31 May in each year.*

Aurora Energy strongly supports maintaining all aspects of the current methodology as this best reflects the prudent hedging approach adopted by retailers compared to Options 2 and 3 by ensuring that:

- the volume weighted costs to hedge the Tasmanian small customer load profile are fully reflected in the WEP calculation; and
- reduces load and price variation risks to Aurora Energy by setting the WEP as close as possible to the start of the period/s that Aurora Energy is hedging for.

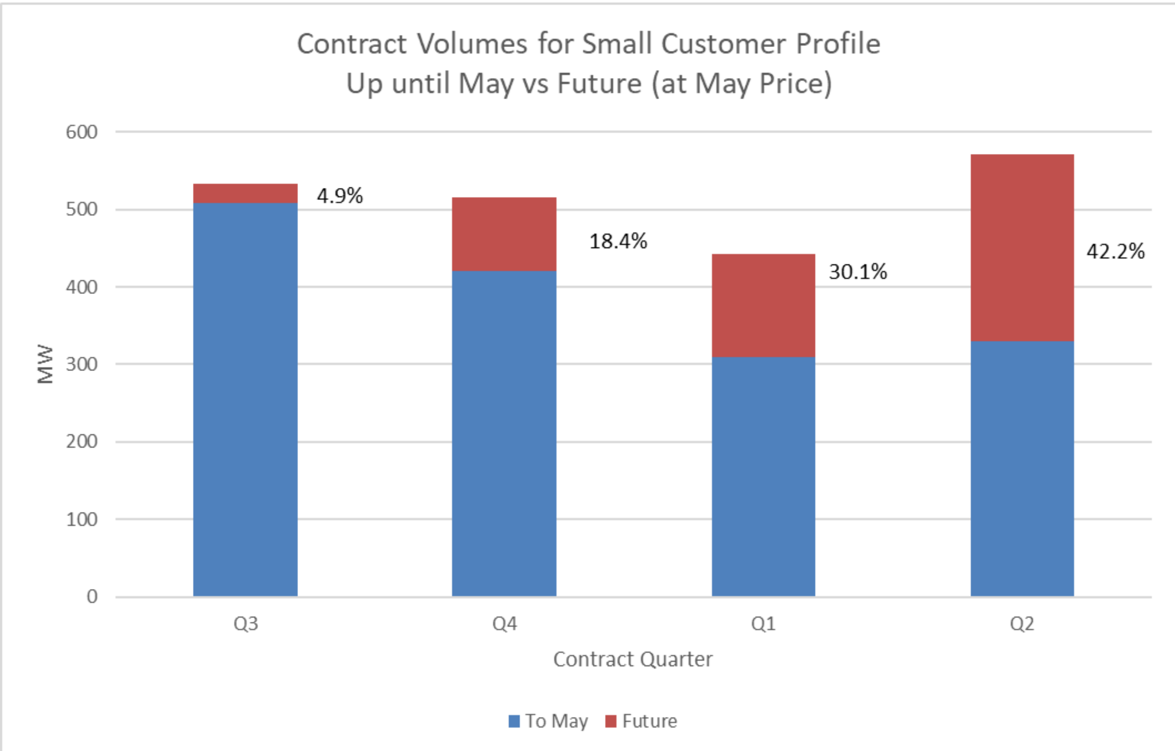
As set out in Graph 1 below, in practice the current methodology weights contract volumes to reflect the load profile of Tasmanian small customers. In effect, this sees the WEP reflect higher contract volumes for the winter periods of Q2 and Q3.

Graph 1: WEP methodology contract volumes to reflect hedging of small customer load profile.



Graph 2 below further illustrates that when the WEP is set in May each year, a component of future prices is set based on the price as at the time when the WEP is finalised. This varies by quarter with 42 per cent of the Q2 contract priced at the May price.

Graph 2: WEP methodology Pre-May vs Future Price weighting



Whilst this approach does not appear optimal, it does seek to reflect the fact that prudent hedging will see retailers hedge progressively up until the start of each quarter. In this context, the current methodology still reflects a more prudent hedging approach with lower wholesale risk to retailers than that associated with the approach applied in other jurisdictions.

The lower wholesale risk for retailers under this option is associated with the fact that by leaving the pricing in for this future load later in the methodology (May annually), and therefore as close as possible to the start of the period that those contracts take effect, this lowers wholesale risk associated with changes in expected customer load that retailers seek to hedge. When compared to the approach adopted in other jurisdictions, the ESC, AER, and ICRC all uses methodology's that include the full contract volumes retailers need to hedge the relevant customer usage profiles.

In practice, this means that the future volumes reflected in Option 1 in Tasmania are effectively brought forward in other jurisdictions respective methodologies and averaged in periods prior to when their WEP prices are set. This means other jurisdiction methodologies price volume in much earlier than what the Regulator's current methodology does. Consequently, other jurisdictional methodologies are arguably less prudent than that currently adopted by the Regulator in Tasmania by having a methodology that prices volume in as close as possible to the start of the quarter that the retailer is hedging for.

6.2 Option 2 – April calculation: using the last Tuesday in April as the cut-off point to calculate the WEP for the following year.

Consistent with the way prudent retailers manages wholesale risk, Aurora Energy's position is that the WEP calculation should be as late as possible in the Standing Offer Price reset process.

While other regulators do set their cut-off dates earlier than the WEP calculation, this is driven by the need to finalise their cost for wholesale energy earlier. For example, while the OTTER must provide Aurora Energy with the calculated WEP by 24 May of a given year, the 2024/25 price was not approved until 17 June 2024. By contrast the AER Default Market Offer (DMO) and the Essential Services Commission (ESC) Victoria Default Offer (VDO) must be set at approximately the same time that the WEP is provided to Aurora Energy. Therefore, the AER and ESC must set any cut-off date for data earlier than the Regulator to be able to meet their legislated deadline.

In the 2022/23 DMO final determination the AER notes the importance of setting as late a cut-off date as possible to use data that is current. For the 2022/23 DMO determination the DMO regulations were changed so that the AER would make its final determination at the end of May instead of the start. Consequently, they noted that one of the impacts was that:

> *"Our wholesale and environment forecasts are based on a later cut-off for wholesale market data (13 May). This means our estimates will reflect more current market trends and developments that will impact prices in the forecast period."*[2]

Additionally, stating that:

> *"We further note that the later cut-off for wholesale market data means that most current risk assumptions as foreseen by the market are taken into account in the WEC estimates through updated contract data."*[3]

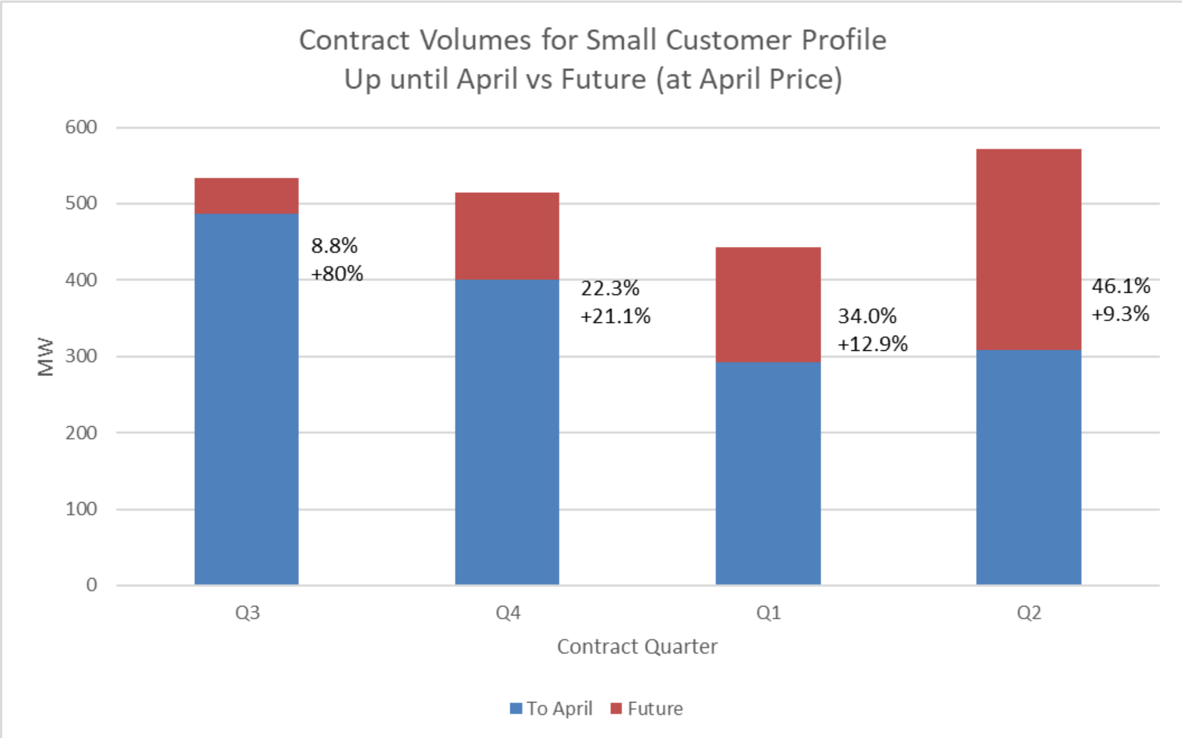
[2] Australian Energy Regulator, Default market offer prices 2022–23: Final determination, 26 May 2022, p. 15.
[3] Australian Energy Regulator, Default market offer prices 2022–23: Final determination, 26 May 2022, p. 26.

Using the latest cut-off date for data was supported by Energy Australia in their submission to the 2022/23 DMO draft determination.[4]

Aurora Energy agrees with the AER and Energy Australia that the most up to date data should be used when calculating wholesale costs. Using up to date data limits price risk, which is pointed out by Regulator, with the WEP methodology successfully capturing events that occurred in 2017/18 and 2022/23. Without including data through May, the calculated WEP would have been materially lower than actual costs incurred by Aurora Energy progressively hedging load through this time. This risk also impacts consumers in years when contract prices are trending down, where using an April date would result in a WEP higher than it otherwise would have been.

In the Draft Methodology Paper, the Regulator's analysis has focused solely on the price outcomes with no assessment of the risks and impacts on the standing offer retailer. As illustrated in Graph 3 below, bringing forward the setting of the WEP by 4 weeks to the last Tuesday in April would result in a removal of actual data observations and extending unobserved pricing data points that will only add to the likelihood that calculated WEP is not representative of actual wholesale costs, increasing the risks faced by Aurora Energy.

Graph 3: WEP methodology Pre-April vs Future Price weighting



Relative to Option 1, this would increase the risk to Aurora Energy of hedging higher volumes earlier, increasing exposure to load changes between time of hedging and when that period begins.

The Regulator notes in the Draft Methodology Paper that the exception of 2017-18 and 2022-23, the WEP calculated under the Option 1 and Option 2 calculation methods are closely aligned. Aurora Energy notes that in 2017/18 the April approach would have resulted in a higher WEP if Option 2 was used, whist in 2022/23 a lower WEP would have resulted if option 2 was used.

[4] EnergyAustralia, Submission to DMO 4 draft determination, 17 March 2022, pp. 11-12.

Given that Option 2 produces WEP outcomes consistent with that of Option 1 but results in an increase in wholesale risk to Aurora Energy relative to Option 1, Aurora Energy does not support Option 2 to bring forward the WEP calculation date to the last Tuesday in April.

6.3 Option 3 - No future price method - the current method except that both the LFS contract price and Absolute Minimum Capacity Offer volume for all weeks after the WEP calculation date are set to zero.

Aurora Energy has concerns with the approach the Regulator has adopted in removing future price periods from the WEP calculation in assessing Option 3.

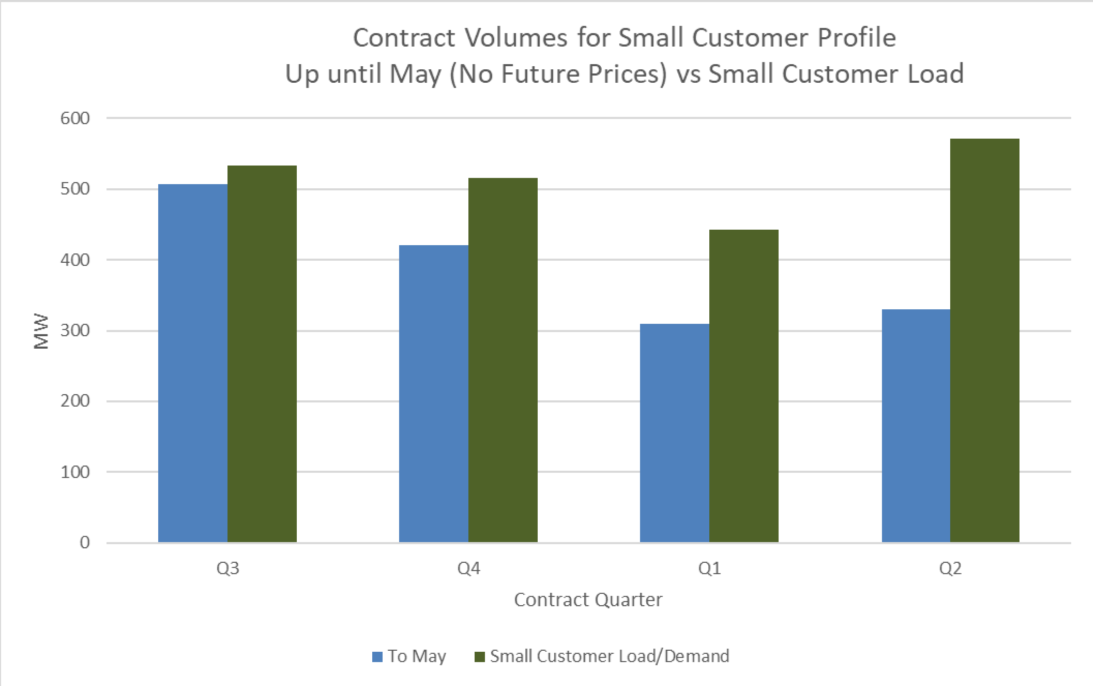
By setting both the LFS contract price and the absolute minimum capacity offer volume for all weeks after the WEP calculation date to zero, the methodology no longer reflects the weighted volume of contract load that a retailer will need to hedge its retail load. As illustrated in graph 2 in the assessment of Option 1, this approach simply removes future volume required to hedge the Tasmanian small customer load but does not substitute this volume back in the methodology that is necessary to ensure it reflects the hedging costs of Tasmanian small customer demand. As designed, the 'no future price' method only accounts for 72 per cent of the total load hedged by the current method. As illustrated in Table 3 below, over the 11 years that the WEP has been calculated on average only 54 per cent of the hedged volume for Q4 occurs before the WEP calculation date.

Table 3 – Proportion of Volume Hedged by the WEP Calculation Date (May)

WEP calculation year	Q1	Q2	Q3	Q4	Total
2014-15	84%	54%	40%	32%	**46%**
2015-16	92%	79%	57%	47%	**68%**
2016-17	94%	82%	69%	57%	**75%**
2017-18	94%	82%	69%	56%	**75%**
2018-19	94%	81%	68%	55%	**75%**
2019-20	94%	82%	69%	56%	**75%**
2020-21	94%	82%	69%	57%	**76%**
2021-22	93%	81%	70%	57%	**74%**
2022-23	95%	82%	71%	57%	**76%**
2023-24	95%	82%	71%	59%	**76%**
2024-25	95%	82%	70%	57%	**76%**
Average	**93%**	**79%**	**66%**	**54%**	**72%**

By removing this load from the calculation, a higher proportion of the price is weighted through the first three quarters, with overall price highly impacted by Quarter 3 pricing due to the highest proportion of priced volume. Significantly, 25 per cent of total volume and 43 per cent of the higher priced winter demand period Quarter 2 contract costs necessary to hedge small customer demand are excluded from the weighted WEP methodology. Consequently, it is not surprising that the Regulators assessment of the price impacts results in a lower WEP as a significant portion of higher costs contract periods are removed. This price analysis, however, is not representative of the hedging costs of Tasmanian small customer load/demand. Graph 4 below compares load necessary to hedge Tasmanian small customer load/demand to that included in the Regulators WEP methodology for Option 3.

Graph 4: Tasmanian Small Customer Load/Demand vs WEP methodology for Option 3



Furthermore, in removing future contract volume reflective of that, that a retailer would need to acquire to hedge the Tasmanian small customer profile as presented in option 3, this will result in a WEP methodology that is not in line with the Regulators requirement under 40AB(3)(C) of the ESI Act that requires the Wholesale Electricity Cost to be:

> 40 AB (3) (C) *"related to the same number of units of electricity as the number of units of electricity purchased by the retailer for the purposes of providing those services.".*

In practice, any widening of the period between which load is contracted and when the relevant quarter that those contracts take effect, exposes Aurora Energy to changes in retail load relative to that contracted. For Aurora Energy, this load risk relates to customer churn and as well as weather driven demand outlook. This would result in increased risk of long contract positions should customer churn be realised. This risk is greater in Tasmania than in other justifications for the following reasons:

- In other jurisdictions, the WEC set in other jurisdictions DMO's only applies to approximately 15-20% of retailers load whilst in Tasmania the WEC allowance reflects the price for near 100% of customers.
- No futures exchange exists in Tasmania to support contract trading. Whilst an over-the-counter market exists, Hydro Tasmania as a generator is not a natural buyer of contracts. In this case, should Aurora Energy have a net long contract position as a result of customer churn, there are limited avenues, relative to other jurisdictions, to unwind contract length positions by selling contract length.

Based on Option 3 being incongruent with the Regulators requirement under 40 AB(3)(C) of the ESI Act to determining the wholesale Energy cost as well as the increased risks that Option 3 presents relative to Option 1, Aurora Energy is not supportive of Option 3 or any alternate that seeks to bring forward future hedging into periods any earlier than May (annually) as per the current methodology.

6.4 - Summary

- Aurora Energy's preferred methodological option for calculating the WEP is Option 1, the current method.
- Volume weighted costs to hedge the Tasmanian small customer load profile are fully reflected in the WEP calculation.
- It is critical to reduce load and price variation risks to Aurora Energy by setting the WEP as close as possible to the start of the period/s that Aurora Energy is hedging for.

7. Renewable Energy Costs

Aurora Energy proposes that the Regulator move to a full market-based approach for the calculation of Renewable Energy Costs (RECs).

In the 2022 Determination, the Regulator sought to apply an approach based on full reference to market values for RECs. At that point in time, the full market approach presented a material risk to Aurora Energy and its Cattle Hill contract as there was limited time to mitigate potential impacts before the 2022 Determination was to take effect.

As a result, Aurora Energy requested the Regulator adopt a hybrid approach that mitigated risk to Aurora Energy by effectively reflecting both Cattle Hill costs and a market average. Ultimately, the Regulator adopted this hybrid approach.

Since the 2022 Determination, there has been significant changes in the large-scale generation certificates (LGC) market with increased demand from corporate, commercial and industrial demand to meet renewable claims. The resultant impact has been an increase in demand from customers seeking to voluntary surrender Tasmanian generated LGC's to make these green claims certifiable. This change in market demand has resulted in the risks to Aurora Energy of moving to 100 per cent market approach, as sought by the Regulator in the 2022 Determination, being mitigated.

For the 2025 Determination, Aurora Energy contends that a shift to a full market-based approach is in the interests of both customer and the broader market based on:

- The risks associated with seeking a hybrid approach have reduced.
- Overarching costs associated with a market-based approach are set to significantly reduce over the next three years based on current forward market prices.
- The expanded capacity Investment Scheme (CIS) will increase LGC generation with increasing supply expected to place further downward pressure on LGC prices over the term of the 2025 Determination.
- It will ensure that RET costs in Tasmania are consistent, and not higher, than those in other jurisdictions.
- Competition impacts that may arise given a new market entrant or existing entrant seeking to expand may not have access to the same contract prices (as Aurora Energy) and could face costs that are higher than the 2025 Determination allowance, thereby discouraging competition from existing or new entrants retailers in Tasmania.

These factors are further expanded on below.

7.1 Implications of Contract vs Market Based approach

Most regulators set the allowance for the costs of complying with renewable schemes based on market benchmarks. The Regulator notes that other regulators including the ICRC, QCA and ESC estimate their respective retailers' costs of complying with the Australian Government's mandatory renewable energy schemes using a market-based approach.

In addition, the AER also uses a market-based approach (circa $40/LGC nominal for 2024/25) who noted in its recent determination: "*we propose to retain our market-based approach to environmental cost forecasting with updates for new and amended schemes… we remain of the view that a market-based approach that develops a trade-weighted average price based on all trades for the relevant period is appropriate*."[5]

There are three key reasons regulators have preferred setting these energy allowances based on market benchmark prices, these are:

- best reflect the opportunity costs or the value of the resources in alternative uses at that point in time, promoting allocative efficiency in the provision of services;
- facilitate efficient entry and competition in retail markets, promoting over time dynamic efficiency in the provision of services; and,
- provide incentives to improve efficiency and the productive efficiency in the provision of services.

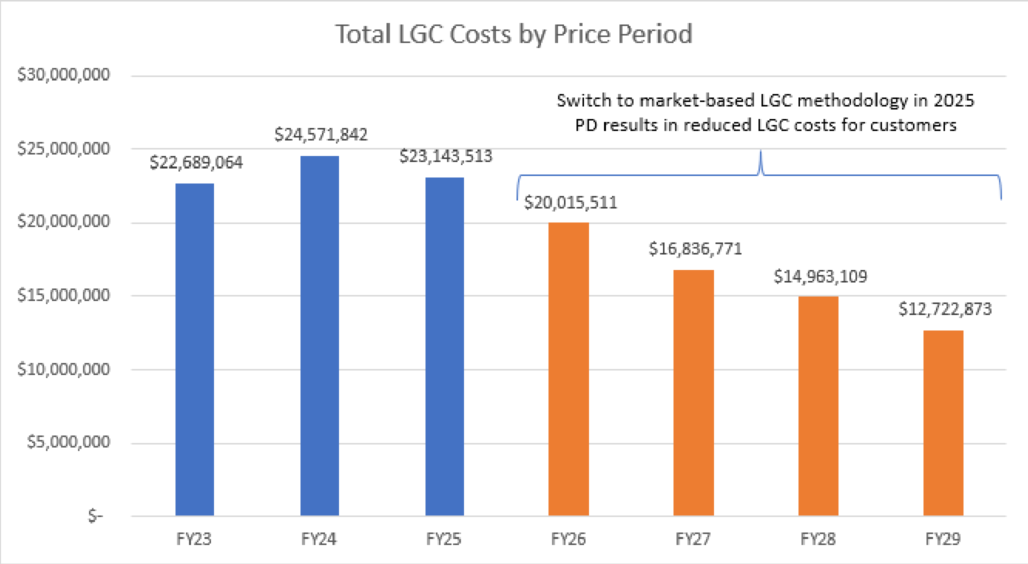
One of the key reasons that regulators have preferred setting these energy allowances on the basis of benchmark prices is that where products are available in competitive and liquid markets (they can be bought and sold easily at an observable price), this benchmark market price is the best estimate of the efficient cost of the product, consistent with the opportunity cost principle. That is, in a competitive market, market prices reflect the value of resources in alternative uses at that point in time. This promotes allocative efficiency in the provision of services.

In addition, it should be recognised that comparing outcomes of contract vs market-based approaches need also to consider market dynamics and risks over the forward period to which the methodology is to take effect. Whilst the Graph 5 below reflects the current market view based on current market prices, the impacts of the expanded CIS have yet to be fully reflected in forward market prices. The CIS will increase LGC generation as projects come online with increasing supply expected to place further downward pressure on LGC prices over the term of the 2025 Determination. This will result in greater opportunity for lower prices under a 100 per cent market-based approach relative to the current hybrid approach that will only expose customers to a circa 40 per cent of market based prices.

Importantly, by moving to the 100 per cent market approach, Aurora Energy expects LGC costs for customers to reduce and also be in line with outcomes in other jurisdictions in the VDO and DMO.

[5] AER, Default market offer prices: Final Determination, May 2024, p.42

Graph 5: Total Large-scale Generation Certificate Costs by Price Period



Estimated LGC costs of 100% market based approach from FY26 to FY29 reflects forward market prices and load assumptions as at March 2024

<u>*7.2 Impact on competition from lower then achievable contract costs*</u>

Another key reason that regulators have preferred setting these energy allowances based on benchmark prices is to ensure efficient entry and competition in retail markets. Aurora Energy notes that it is consistent with the Regulator's objectives under the ESI Act in regulating Aurora Energy's standing offer prices to promote efficiency and competition.

A retailer that is seeking to enter the Tasmanian market, or an existing retailer that is seeking to expand its market share, will be required to surrender LGCs to the Clean Energy Regulator (CER). It may purchase these LGCs at current market prices or it may enter Power Purchase Agreements.

Setting prices based on market prices will ensure there are incentives for entry and expansion by other retailers, which over time promotes dynamic efficiency. Regulators have previously highlighted the importance in promoting dynamic efficiency, and the benefits it provides in terms of innovation and efficiency, as the best long term means of protecting customers. Further, setting a market price that undermines competition creates additional inefficiency in the market.

In this context, consideration of competition law is important and neither Aurora Energy or the Regulator should support a methodology that may have the effect of reducing competition over the term of the Determination particularly at a time where there has been expansion of retail providers, and importantly choice for customers, in Tasmania.

8. Basslink Costs

Aurora Energy contends that transmission services are essential to the Tasmanian energy system's ability to supply energy to customers and interconnecting services, such as Basslink, are an integral aspect of energy security services and the balancing of on-island energy needs.

Transmission network economic price regulation is highly prescribed and is delivered by the Australian Energy Regulator under the National Electricity Laws and Rules with a range of tests and structures employed to ensure these are efficient and prudent costs.

This regulation is established on the basis that costs associated with regulated assets such as Basslink flow though Co-ordinating Network Service Providers (CNSPs), such as TasNetworks, and appropriately assigned to authorised retailers operating in Tasmania.

Consequently, costs related to services such as Basslink should be appropriately recovered from all electricity customers in Tasmanian regulated retail prices.

Aurora Energy notes that the Regulator is seeking comments on the treatment of costs relating to Basslink in the event that the AER decides that pricing of Basslink's services should be regulated. In his paper, the Regulator is challenging whether Basslink provides a cost that relates to the provision of retail services and is seeking feedback on whether these costs should be passed through to regulated customers.

Regarding this proposal, Aurora Energy's understanding of the transmission regulatory framework and pending outcomes of assessment of Basslink as a regulated link, that Basslink will recover its revenue through TasNetworks for Tasmania and AEMO for Victoria. Given TasNetworks is currently the sole provider of transmission services and is responsible for the aggregate annual revenue requirement (AARR) within Tasmania, it will function as the 'Co-ordinating Network Service Provider' for Tasmania after Basslink is regulated.

It is important to note that both Basslink and TasNetworks sit outside the jurisdiction and control of the Regulator. The National Electricity Rules require that TasNetworks, as the Co-ordinating Network Service Providers (CNSP) will recover the revenue for Basslink through its network charges (with this subsequently returned to Basslink). The role of CNSP has been approved by the AER as part of TasNetworks pricing methodology and guidelines.

If the Regulator adopts a decision to not allow Basslink costs recovery it would only be a binding decision on Aurora Energy, not any of the other supply chain participants. This has a range of implications for not only Aurora Energy but multiple market participants, both current and potential entrants.

For Aurora Energy specifically, it would force Aurora Energy into a position of non-cost recovery that would then threaten the viability and sustainability of the Regulated Offer Retailer for Tasmania.

Given the significant pipeline of new generation and transmission projects outlined for the Tasmanian jurisdiction, Aurora Energy suggests that if the Regulator doesn't allow recovery of Basslink costs, this would also trigger a larger structural discussion with parties such as AEMO and the Tasmanian Government.

9. Metering

Aurora Energy is seeking to maintain the current arrangement for all meter cost recovery, including the recovery of annual advanced meter fees and basic meter fees, and some ad hoc advanced meter charges.

The current approach includes forecasting advanced meter fees based on an installation forecast, and subsequently truing up through the 'unders and overs' mechanism. This approach ensures the most accurate pass-through of metering costs during a transitionary period where the forecast roll out of advanced meters can be impacted by external factors. Aurora Energy acknowledges that once the advanced meter roll out is complete, forecasting complexity will reduce and this will provide an opportunity to remove metering costs from the unders and overs without materially increasing risk of recovery to Aurora Energy. However, with the advanced meter roll out still underway, and difficult meters remaining, Aurora Energy considers it appropriate to maintain the current approach over the next determination period.

The current approach also forecasts meter fees in relation to TasNetworks' existing and replaced basic meter fleet. Aurora Energy is seeking to maintain the pass-through recovery of these costs and supports the Regulator's proposal to refine the method for calculating the proportion of TasNetworks' meter fees that relates to regulated customers.

In its Draft Methodology Paper, the Regulator suggests slowing the roll out of advanced meters to align with the AEMC's 2030 deadline, and not the Tasmanian Government's commitment of December 2026. The Regulator states that $0.51M could be saved across the 18 months from July 2025 to December 2026 under this approach. Aurora Energy notes that the commitment for completion of the rollout by 2026 is set to form part of its Statement of Expectations, hence it will be obliged to uphold the commitment of its Shareholders. This will also enable it to take advantage of the operational efficiencies from continuing the current accelerated roll out program, noting that $0.51M when annualised equates to less than 0.06 per cent of the current Notional Maximum Revenue (NMR).

Aurora Energy will look to update list of fees that are currently 'smoothed' in the annual price reset to include costs in relation to wasted visits fees provided by all metering providers in its Preliminary Submission. Further, it will be reviewing exploring the charges passed through for meter reading fees to customers that select to 'opt out' of having communications enabled but who are not in a rural/regional area that cannot accommodate two-way metering communications. The intent here is to ensure additional advanced meter costs are only 'smoothed' across the entire customer base where necessary.

10. AEMO Fees - Unaccounted for Energy

Aurora Energy recommends the Regulator allow for recovery of costs associated with unaccounted for energy (UFE) as part of the Ay element of the Notional Maximum Revenue (NMR) calculation.

Aurora Energy is seeking to recover the cost of 'unaccounted for energy' (UFE) that is now present in AEMO wholesale market invoices.

UFE is the difference between all adjusted metered energy entering a local area, compared to all adjusted metered energy consumed within the local area. These differences could be caused by energy theft, inaccurate or faulty meters, estimation errors associated with unmetered devices, profiling of reads to the trading interval (5 minute) level or errors in the distribution loss factor (DLF).

Since the introduction of Global Settlements all retailers commenced being billed by the Australian Energy Market Operator (AEMO) for UFE within their distribution area. AEMO allocates UFE to market customers in each local area, pro-rated based on their "accounted-for" energy.

UFE forms part of weekly AEMO settlements and charges to Aurora Energy. Weekly energy purchase charges invoiced to Aurora Energy by AEMO include the amount of UFE in megawatt hours for each Transmission Node Identifier (TNI). This is calculated as the difference between energy consumed at the TNI and the total sum of energy consumed at the National Metering Identifiers (NMIs), adjusted for AEMO's published DLFs for the financial year.

In addition to Wholesale Energy, Aurora Energy also incurs Renewable Energy Certificate expenses and Ancillary and Market charges on UFE due to the way AEMO and the CER calculate their charges. Network use of system charges are billed at the NMI level and therefore do not result in additional charges relating to UFE.

All three categories of costs relating to UFE (energy purchase costs, REC expenses and ancillary and market charges) are not currently included in the Notional Maximum Revenue (NMR) calculation Aurora Energy currently receives from its Standing Offer customers, thereby effectively reducing Aurora Energy's retail margin.

Aurora Energy's view is UFE is most appropriately recovered through the AEMO fees aspect of the Notional Maximum Revenue (NMR) calculation and allowed to be trued up via the unders and overs adjustment mechanism due to the 30-week settlement delays in receiving final data from AEMO. Alternatively, the Regulator may allow for a direct cost pass-through of actual UFE costs with a one-year lag (i.e., actual UFE costs in FY2025 are recovered in prices for FY2026).

In terms of alternative approaches, it is noted that while the AER does not include UFE in the DMO price, crucially they do not dismiss the validity of UFE as a cost that retailers incur. Rather they are unable to assess the materiality of such a cost to a singular retailer because there is no publicly available data. This is not the case for OTTER, where prices are determined based on Aurora Energy's cost base.

11. Late Payment Fee (LPF)

Aurora Energy flags that as part of its Preliminary Submission, it will be seeking to increase the current LPF of $5 to a level that is more commensurate with LPFs charged by other similar businesses . Aurora Energy will draw upon multiple examples of similar utility companies (energy, water and telecommunications) in order to provide comparative reference points. As part of this discussion, we are reviewing whether related functions, such as interest charged on overdue accounts, also need review and resetting.

12. Regulated Retail Tariff Strategy

As part of the upcoming price investigation, Aurora Energy will propose a Regulated Retail Tariff Strategy (Tariff Strategy that will shape and guide the application of its regulated tariffs for residential and small business customers) across the life of the 2025 Determination. This will include:

- consideration of the purpose of regulated tariffs,
- a review of recent drivers for change to regulated tariffs, such as revised network pricing and assignment rules;
- the potential to introduce new tariffs; and,
- cost reflectivity in regulated tariffs and rebalancing of tariffs

To ensure the Tariff Strategy is well understood, tested and accepted, Aurora Energy will be holding a stakeholder forum in late August to canvass the above key matters. This will inform the Draft Tariff Strategy set to be submitted to the Regulator on 15 October 2024.

Aurora Energy notes that as part of engagement with stakeholders on the form of the rebalancing, Aurora Energy will propose a methodology that is essentially locked in for the life of the Determination to ensure certainty for all relevant stakeholders over the way in which retail tariffs can be adjusted on a year-on-year basis.