office of the tasmanian economic REGULATOR

REVIEW OF THE APPROACH TO REGULATING RETAIL ELECTRICITY PRICES

FINAL METHODOLOGY PAPER

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TABLE OF CONTENTS

OVERVIEW

This paper summarises the Regulator's approach to determining the maximum standing offer (regulated) prices that Aurora Energy can charge small customers in Tasmania on standard retail contracts for the supply of electricity for the regulatory period commencing on 1 July 2025.

The Regulator's approach for the 2025 Determination is summarised in Table 1. The Table also compares the approach to the approach applied under the current 2022 Determination.

This paper and the methodologies set out in it do not apply to Aurora Energy's customers on market retail contracts, nor does it apply to the prices charged by other retailers offering market retail contracts in Tasmania.

Table 1: Comparison of current approach and the approach for the 2025 Price Investigation and Determination

Component	Current approach (2022 Determination)	Approach for the 2025 Price Investigation and Determination	Chapter reference
Overall approach	Cost build-up approach.	No changes are proposed.	Chapter 2
Wholesale electricity costs (WEC)	The WEC is based on the wholesale electricity price (WEP), forecast customer load adjusted for distribution and marginal loss factors.	No changes are proposed.	Chapter 3
WEP	The WEP is calculated in accordance with the *Electricity Supply Industry Act 1995* and the Standing Offer Price Approval Guideline. The WEP is calculated in late May each year and includes a forecast of future prices in some weeks.	The Regulator has decided to maintain the current timing of the WEP calculation. While the Regulator considers that a 'no future price' method (which is based on historical prices with no forecasts of future prices) has merit, the Regulator intends to consult further on this method with stakeholders, including other electricity retailers,	Chapter 3

Component	Current approach (2022 Determination)	Approach for the 2025 Price Investigation and Determination	Chapter reference
		during the pricing investigation.[1]	
Network costs	Network costs are calculated by multiplying the Australian Energy Regulator's (AER) approved network tariffs by forecast billing days and customer load for each retail tariff, for the applicable period, and then summing the resultant values. Billing days used in deriving network costs are reconciled with the forecast of the customer numbers used in the Notional Tariff Base.	While the Regulator has decided that the overall approach to calculating network costs will remain unchanged, the Regulator has also decided that further information is required before a decision can be made in relation to the treatment of Basslink costs should Basslink become a regulated service.	Chapter 4
Cost to serve (CTS)	A per customer CTS amount was derived using a combination of bottom up and benchmarking approaches. The calculation also included: ▪ an efficiency factor; ▪ a mechanism to reflect changes to Aurora Energy's customer numbers[2]; and ▪ indexing labour cost components by the Tasmanian Wage Price Index and all other components by the Hobart CPI.	The Regulator has decided to adopt a similar approach, except that the Regulator has decided to: ▪ remove the mechanism that takes account of changes in customer numbers; ▪ further consider the treatment of cloud-based software costs during the pricing investigation; and ▪ require Aurora Energy to submit its cost allocation	Chapter 5

1 The 'no future price' method is similar to the current method of calculating the WEP except that it is based only on historical prices and contains no forecasts.

2 Under this mechanism, Aurora Energy's per customer CTS increases if Aurora Energy's customer numbers decline as there would be fewer customers to recover fixed costs from and decreases if customer numbers increase i.e. there would be more customers to recover fixed costs from.

Component	Current approach (2022 Determination)	Approach for the 2025 Price Investigation and Determination	Chapter reference
		manual at the same time as it lodges its submission in relation to the pricing investigation.	
Renewable energy target (RET) costs	Aurora Energy's long term contractual commitments under the Cattle Hill Power Purchase Agreement were included in Aurora Energy's cost allowance for Large-scale Generation Certificates (LGCs)[3]. The forward price for the remaining LGCs in the relevant year were estimated as the average weekly forward LGC price over 12 months of the previous year. The Clean Energy Regulator's Small-scale Technology Percentages were used to calculate Small-scale Renewable Energy Scheme costs.	No changes are proposed.	Chapter 6
Metering costs	In estimating costs for metering services, the Regulator used a weighted average cost of meters by tariff applied to the notional tariff base (NTB).	While the overall proposed approach remains unchanged, the Regulator has decided to refine the method for calculating the proportion of regulated customers on various tariffs.	Chapter 7
Retail margin	During the 2022 price investigation the Regulator adopted a benchmarking approach to setting Aurora Energy's retail margin and calculated it on a fixed amount per customer basis.	The Regulator has decided to continue to use a benchmarking approach, but will further consider the method for calculating the retail margin during the pricing investigation.	Chapter 8

[3] A Power Purchase Agreement is a contract most commonly between a renewable energy generator and an electricity retailer that allows the retailer to purchase LGCs at predetermined prices over an extended period of time (typically around 10 years). A PPA assists the retailer to manage risks relating to supply issues and price volatility in the LGC market.

Component	Current approach (2022 Determination)	Approach for the 2025 Price Investigation and Determination	Chapter reference
Australian Energy Market Operator (AEMO) costs	AEMO costs were estimated by applying AEMO's draft published fees and charges and a forecast of ancillary charges for the relevant period to the NTB.	No changes are proposed.	Chapter 9
Adjustments for under and over recoveries	The difference between forecast and actual costs for each period were passed through to small customers in the next period. Under and / or over recoveries are limited to network costs, metering costs, RET costs and AEMO charges.	While the Regulator has decided to continue with the overall approach for adjustments, the Regulator will further consider the treatment of unaccounted for energy during the pricing investigation.	Chapter 9

1 INTRODUCTION

The *Electricity Supply Industry Act 1995* (the ESI Act) requires the Regulator to determine the maximum prices that Aurora Energy may charge small customers under standard retail contracts. Under the ESI Act, Aurora Energy proposes, and the Regulator considers for approval, standing offer (regulated) electricity prices. Further details on the legislative framework are contained in Attachment 2.

The current price determination, the *Aurora Energy Pty Ltd 2022 Standing Offer Price Determination* (2022 Determination), expires on 30 June 2025 and the Regulator is required to make a new price determination that will cover the regulatory period commencing on 1 July 2025. Before making the new price determination, the Regulator is required to conduct a pricing investigation.

As part of the investigation process, on 5 July 2024, the Regulator released its Review of the approach to regulating retail electricity prices - Draft methodology paper (Draft Methodology Paper) for public consultation. The Draft Methodology Paper reviewed the methodologies of previous determinations, the arrangements in other jurisdictions and set out the Regulator's proposed approach for the next investigation and determination.

The Regulator received seven submissions on the Draft Methodology Paper and also held meetings with four stakeholders. A list of submissions and meetings are contained in Attachment 3 and the submissions and summaries of the meetings are available on the Regulator's website at 2025 Standing Offer Investigation and Determination.

After considering the issues raised by stakeholders, the Regulator's approach to determining standing offer prices in its 2025 Standing Offer Price Determination (2025 Determination) is set out in this paper.

This paper does not consider Aurora Energy's costs nor set standing offer electricity prices from 1 July 2025. Rather, this paper deals with the approaches the Regulator will adopt in assessing the efficiency of Aurora Energy's costs and determining the resultant maximum prices for the 2025 Determination.

1.1 Next steps and timeline

During the pricing investigation, the Regulator will issue and consult on a draft investigation report, a draft determination and a draft standing offer price approval guideline. The Regulator will also consult on Aurora Energy's draft standing offer tariff strategy.

Table 2 sets out the timeline for the upcoming pricing investigation.

Table 2: Timeframes for the 2025 pricing investigation and determination

Description of task	Anticipated due date
Regulator releases Notice of Intention to conduct a pricing investigation	October 2024
Aurora Energy lodges its preliminary submission and its draft tariff strategy	15 October 2024
Regulator releases its draft report, draft price determination, draft standing offer price approval guideline and Aurora Energy's draft tariff strategy for public consultation	21 February 2025
Consultation on the Regulator's draft report, draft price determination, draft standing offer price approval guideline and Aurora Energy's draft tariff strategy closes	21 March 2025
Regulator releases its final report, final price determination and final standing offer price approval guideline and approves Aurora Energy's tariff strategy	2 May 2025
Aurora Energy submits its pricing proposal for 2025-26 to the Regulator for approval	30 May 2025
Regulator approves 2025-26 standing offer prices (consistent with the final price determination)	Prior to 1 July 2025

2 APPROACH TO SETTING MAXIMUM STANDING OFFER PRICES

Regulator's decision:
The Regulator has decided to continue with the current cost build-up approach to determine maximum standing offer prices.

2.1 Background

Regulated prices are set at a level that enables Aurora Energy to recover the costs of supplying electricity to customers on standard retail contracts. These costs include:

- wholesale electricity costs;
- network costs;
- Aurora Energy's retail costs (cost to serve);
- renewable energy target (RET) costs;
- metering costs; and
- other costs, such as Australian Energy Market Operator (AEMO) costs.

In addition to these costs, a retail margin is applied to reflect the risks Aurora Energy incurs in providing retail services to small customers under standard retail contracts. Other inputs used in the calculation of these components are loss factors, forecast customer numbers and forecast total load (together the latter two inputs are referred to as the Notional Tariff Base or NTB).

This methodology is referred to as a cost build-up approach. Under this approach, each component is summed to arrive at a total value of forecast costs for the year which is referred to as the Notional Maximum Revenue (NMR). The NMR is calculated solely for the purpose of determining maximum standing offer prices. Further, the NMR, as a notional figure relating only to standing offer customers, is not reconcilable to Aurora Energy's actual financial performance information.

The cost build-up approach is used by other regulators when regulating electricity prices and is a well-established and accepted approach. Furthermore, the individual cost components are generally consistent across jurisdictions which is useful for comparisons.

It is by examining each cost component that the Regulator seeks to ensure that standing offer customers do not pay more than necessary for the services they receive.

2.2 Draft Methodology Paper

In its Draft Methodology Paper, the Regulator proposed to continue to use a cost build-up approach to set maximum standing offer prices.

The Regulator also sought views from stakeholders on alternative methods for forecasting customer numbers, such as forecasting customer numbers based on the average rate of growth or decline in actual customer numbers over the previous five years.

2.3 Submissions

Aurora Energy did not support using five-year growth or decline rates to forecast customer numbers. It considered that such an approach would not provide an accurate forecast of customer numbers due to the changing nature and increased competition in the Tasmanian electricity retail sector.

The Tasmanian Small Business Council (TSBC) considered that using actual customer numbers would be more transparent than the current approach but would be concerned if this approach were to result in price increases for customers.

2.4 Regulator's approach

Consistent with previous investigations and arrangements in other jurisdictions, the Regulator has decided to continue to use the cost build-up approach.

The Regulator recognises the changing nature of the electricity market in Tasmania and has decided to set customer numbers using the current approach. That is, using the mid-point of actual customer numbers as at 31 March prior to the start of the year and a forecast of customer numbers as at 31 March during the year.

3 WHOLESALE ELECTRICITY COSTS

Regulator's decision:

The Regulator has decided to maintain the current timing of the wholesale electricity price (WEP) calculation.

While the Regulator considers that a 'no future price' method (which is based on historical prices with no forecasts) has merit, the Regulator intends to consult further on this method with stakeholders, including other electricity retailers, during the pricing investigation.

3.1 Background

Under the current approach, the calculation of the wholesale electricity costs (WEC) component of the NMR is based on the WEP, forecast customer load and distribution and marginal loss factors.

As is required under the ESI Act, the WEP is based on the load following swap (LFS) price, which is a financial contract type that Hydro Tasmania is required to offer.

The LFS sets the price that Tasmanian electricity retailers pay to purchase a certain amount of electricity in a given future quarter of the year at a certain time interval of the day. Importantly, the LFS differs from the electricity spot price and is a product available to retailers to mitigate the risks of paying spot prices for the electricity they need to meet the demand from their customers.

Under the ESI Act, the Wholesale Contract Regulatory Instrument and the methodology set out in the Standing Offer Price Approval Guideline, the Regulator uses Victorian forward contract prices, adjusted for Tasmanian demand and supply conditions to derive LFS prices and, in turn, the WEP.

3.2 What other regulators do

To estimate future wholesale electricity costs in their respective cost build-ups, each of the Essential Services Commission (ESC), the Australian Energy Regulator (AER), the Independent Competition and Regulatory Commission (ICRC), and the Queensland Competition Authority (QCA) use an electricity futures market-based approach and engage consultants to assist with this task. For example, the ICRC estimates energy purchase costs by calculating the average of NSW electricity futures prices, plus an uplift factor that compensates for the spot price volatility risk in the NEM. To date, the ESC and ICRC have engaged Frontier Economics, while the AER and QCA have engaged ACIL Allen to assist with forecasting these costs.

In calculating wholesale electricity prices for 2023-24, each regulator in other jurisdictions used the ASX listed contract price as follows:

- ESC used trade weighted ASX Energy contract prices from the previous 12 months, with prices as at the last Friday in April used as the final price.
- AER and QCA used trade weighted average daily ASX Energy contract prices from the date the contract was listed until 10 May 2023.
- ICRC used the 23-month average of ASX Energy contract prices from 1 June 2021 to 30 April 2023.

In summary, regulators in other jurisdictions estimate wholesale electricity prices for the following year at an earlier point in time than the Regulator currently does in Tasmania.

3.3 Draft Methodology Paper

In its Draft Methodology Paper, the Regulator presented analysis on the timing of the WEP calculation. Three approaches were assessed:

1. May calculation - the current method;
2. April calculation - using the last Tuesday in April as the cut-off point to calculate the WEP for the following year; and
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 Regulator sought feedback from stakeholders on these approaches and invited stakeholders to suggest other alternative approaches.

3.4 Submissions

Aurora Energy supported the retention of the current method of calculating the WEP. It considered that this approach best reflects the prudent hedging approach of a retailer and presents the least wholesale risks to Aurora Energy.

Aurora Energy considered that bringing forward the setting of the WEP to an April calculation date would result in the removal of actual data observations that would add to the likelihood of the WEP not being representative of actual wholesale costs, thereby increasing the risks faced by Aurora Energy. Consistent with the way prudent retailers manage wholesale risks, Aurora Energy considered that the WEP should be calculated as late as possible in the standing offer price reset process.

Hydro Tasmania also supported the current method. It considered that the status quo best reflects the original intent of the WEP pricing approach. It also considered that maintaining the status quo provides certainty to market participants. While the forward-looking assumptions used in the current approach are not reflective of market outcomes, it considered that the 24-month averaging period produces a smoother price path between years. It considered that this smoother price path has the advantage of reducing any potential 'bill shock' for consumers that may emerge as a result of market volatility.

In considering the 'no future price' method, Hydro Tasmania queried whether the two-year averaging period remained appropriate and reflective of the broader market. For example, it noted that a one-year averaging period is applied in calculating the wholesale energy price in the Victorian Default Offer. Therefore, it suggested that it may be worth exploring a one-year averaging approach, especially in light of some of the draw backs of using an assumed price for some forward quarters.

Solstice Energy supported the adoption of the 'no future price' method in order to reduce the reliance on a forecast when calculating the WEP and considered that May is a more relevant time to carry out this calculation. Solstice Energy commented that as marginal loss factors are only available in late May/early June for the following year, it may be prudent to maintain the current timing of the WEP calculation. Further, it commented that the Tasmanian contract prices have been known to have a lagged effect to the Victorian contract market in recent years. Therefore, it considered that setting the WEP in May in effect uses Victorian prices from late April.

Solstice Energy also considered that any changes to the WEP should only be applied in Period 2 of the next regulatory period (the 2026-27 financial year). Further, Solstice Energy considered that, due to the averaging nature of how the WEP is currently set, any changes made to the WEP methodology will have an adverse impact on retailers' management of hedging risks for the 2025-26 financial year, which would effectively have been hedged by then on the assumption that the approach applied under the 2022 Determination for setting the WEP would continue to be used.

TSBC also favoured the use of the 'no future price' method in setting the WEP as it tends to result in a lower WEP on average over time. The TSBC further noted that if there is a change in the method for calculating the WEP, the Regulator should monitor and report on its impacts.

In a meeting with consumer groups, one attendee preferred the 'no future price' method but recognised that, under this method, a lower WEP in the past does not necessarily guarantee a lower WEP in the future.

COTA also requested that additional modelling be undertaken in relation to the 'no future price' method with an April cut-off and further consideration be given to methods used in other jurisdictions.

3.5 Regulator's approach

Having considered the submissions, the Regulator accepts that the WEP calculation should be undertaken as late as possible in the standing offer price reset process which is consistent with how prudent retailers manage wholesale risks. Therefore, the Regulator has decided to maintain the current timing of when the WEP is calculated.

The Regulator acknowledges that the WEP is based on the premise that prudent retailers use forward contracts to reduce their exposure to volatile spot prices. However, the Regulator also acknowledges that there is no perfect method for estimating the WEP and using an assumed LFS price for some weeks, which is currently the case, is not ideal.

Under the ‘no future price’ method, the LFS contract price for all weeks after the WEP calculation date are set to zero. In practice, this means that the WEP calculation is based on the historical weighted-average LFS price only and that no forecasts are required.

Further, the ‘no future price’ method would also set the Absolute Minimum Capacity Offer volume for all weeks after the WEP calculation date to zero. While the Regulator acknowledges that this would mean that the volume for some weeks would be removed from the WEP calculation, the Regulator notes that, in practice, Aurora Energy (and other retailers) would still need to purchase electricity for its customers regardless of how the WEP is calculated.

On balance, while the Regulator considers that the ‘no future price’ method has merit, the Regulator intends to consult further on this method with stakeholders, including other electricity retailers, during the pricing investigation.

In the event that there is a change in the way that the WEP is calculated, the Regulator considers that there may be a need for a transition period. For example, if a different approach is adopted, it may be prudent for the approach to commence on 1 July 2026 as Solstice Energy has suggested.

4 NETWORK COSTS

Regulator's decision:
The Regulator has decided to continue with its current approach to forecasting network costs.
The Regulator has also decided that further information is required before a decision can be made in relation to the treatment of Basslink costs should Basslink become a regulated service.

4.1 Background

Network costs comprise transmission use of system and distribution use of system charges.

Network costs are regulated by the AER. The AER reviews and approves TasNetworks' transmission revenue and distribution regulatory revenue every five years, with the current determination covering the period from 1 July 2024 to 30 June 2029. The AER also reviews and approves TasNetworks' schedule of tariffs each year for compliance with the National Energy Rules (NER) and the five-year regulatory determination. The approved tariffs apply for 12 months from 1 July of each year and are usually set in April or May of the previous year.

Network tariffs comprise a fixed daily charge, consumption charges and, for some tariffs, a demand-based charge. Network tariffs are grouped by network tariff class, which are based on the physical characteristic of the electricity connection (e.g. high voltage) or customer type (e.g. residential or business).

In its Draft Methodology Paper, the Regulator noted that the APA Group Limited (APA), Basslink's current owner, has applied to the AER for approval to convert Basslink from a Market Network Service Provider to a regulated Transmission Network Service Provider (TNSP). Subject to the AER's approval, pricing for Basslink's services would be regulated by the AER for a five-year regulatory control period commencing on 1 July 2025.[4]

In the event that the AER approves APA's proposal, the costs associated with transmission services provided by Basslink could be passed on to small consumers in Tasmania via their retailer. However, under section 40AB(4) of the ESI Act the Regulator has the power to decide to not pass on costs that are not required to deliver network services to customers on standard retail contracts.

4.2 What other regulators do

The approach taken by the ICRC, ESC and QCA in relation to network costs is to pass through the network costs to retailers as calculated by the AER each year. ESC and ICRC allow for

[4] Australian Energy Regulator, Basslink Conversion Application and Electricity Transmission Determination, November 2023; APA Group, Basslink Transmission Revenue Proposal Attachment 4: Revenue and Pricing Methodology, 15 September 2023, page 114.

adjustments in subsequent periods for these costs where the pass-through costs are based on an estimate at the time of setting prices.

ICRC

The ICRC calculates a per MWh network cost by applying the AER approved network tariffs and prices to customer numbers and electricity consumption for the previous 12 months to 31 March each year.

QCA

The QCA sets retail tariffs to apply in regional Queensland and uses the applicable network prices approved by the AER in determining regulated retail prices:

- For small customers on standard retail tariffs, network costs are based on the costs of supply in Southeast Queensland (Energex distribution area).
- For large customers and small customers on limited access obsolete tariffs, network costs are based on the costs of supply on Ergon Distribution's lowest cost region that is connected to the NEM.

ESC

The approach used in the ESC's Victorian Default Offer varies depending on the distribution zone. The regulated electricity prices in each zone include network prices approved by the AER for the distribution network service provider in that zone. The ESC structures the network costs in one of two ways:

- Flat Network Tariffs: a daily supply charge ($ per day) and a flat usage charge ($ per kWh); or
- Two-period time of use network tariffs: a daily supply charge and peak usage and off-peak usage charge.

4.3 Draft Methodology Paper

In its Draft Methodology Paper, the Regulator proposed to continue with the current approach to forecast network costs.

The Regulator also sought comments from stakeholders on the treatment of costs relating to Basslink and the proportion of those regulated network costs that should be passed through to regulated customers.

4.4 Submissions

Aurora Energy considered that Basslink costs should be able to be recovered through regulated prices and noted that both Basslink and TasNetworks sit outside the jurisdiction and control of the Regulator. It also noted that the NER require that TasNetworks, as the Co-ordinating Network Service Provider (CNSP), would recover the revenue for Basslink through its network charges. It further noted that the CNSP has been approved by the AER as part of TasNetworks' pricing methodology and guidelines.

Aurora Energy also considered that if the Regulator does not allow the recovery of Basslink costs, it would only be a binding decision on Aurora Energy and not on any of the other supply chain participants i.e. other retailers that are not subject to price regulation. It considered that this has a range of implications for market participants, both current and potential entrants.

TasNetworks noted that if Basslink becomes a regulated interconnector, TasNetworks will need to apply the transmission pricing rules and recover all the aggregated annual revenue requirement for the use of the transmission assets used to provide prescribed transmission services within Tasmania, including Tasmania's portion of Basslink's regulated revenue.

Hydro Tasmania noted that the recovery of Basslink costs by the standing offer retailer from regulated customers is both consistent with arrangements in other jurisdictions (which have more than one network provider) and with the AER's revenue recovery process.

APA commented that if Basslink becomes a regulated TNSP, it will charge Basslink's regulated revenue to the relevant CNSPs and AEMO. Under the NER, it considered that TasNetworks would recover its share of these costs from distribution and transmission-connected customers in accordance with its AER-determined pricing methodology.

APA considered that the current process outlined in the Regulator's Draft Methodology Paper for the recovery of network tariffs is sufficiently flexible should Basslink become a regulated TNSP.

APA also noted that AEMO will pay settlement residue auction proceeds and charge negative inter-regional settlement residues to TasNetworks for the Victoria to Tasmania directional interconnector, created as a result of Basslink becoming regulated. Under the NER, APA considered that TasNetworks would net off this revenue against its regulated revenue when charging customers. As a result, APA considered that the bill impact on customers from Basslink's conversion will be materially lower that the per annum charges of $8 per Tasmanian residential customer and $15 per Tasmanian small business customer calculated by Basslink and quoted in the Regulator's Draft Methodology Paper. This is because these account only for Basslink's costs and do not include any offsetting revenue from settlement residue auctions.

Solstice Energy recognised that the process for the proposed Basslink regulation is still ongoing. It recommended that once the AER's final decision on Basslink regulation is known, it should be factored into the Regulator's pricing investigation. In particular, it noted that it would be beneficial for the Regulator to consult on any modelled impact of the AER's decision.

TSBC commented that the Regulator should ensure that regulated customers should pay no more than their fair share of Basslink costs. It also queried why small business customers and residential customers would potentially face different bill increases if Basslink becomes regulated when both sets of customers would use the same infrastructure for energy supply.

COTA commented that it is critical that the nature of how Basslink is currently funded is made transparent to ensure that Tasmanian electricity consumers are not, in effect, paying twice for the services Basslink provides.

4.5 Regulator's approach

Consistent with past investigations and arrangements in other jurisdictions, the Regulator has decided to continue with the current approach to forecasting network costs. That is, the network cost component of Aurora Energy's NMR is determined by multiplying the applicable TasNetworks' network tariff by forecast billing days and customer load for each retail tariff and then summing the resultant values. The billing days are then reconciled with the forecast of the customer numbers used in the NTB.

In relation to the treatment of Basslink costs, the Regulator considers that, because the AER's assessment process is still ongoing, more information is needed before the Regulator can make a decision on the treatment of these costs should Basslink become a regulated TNSP.

5 COST TO SERVE

Regulator's decision:

The Regulator has decided to take a similar approach in calculating Aurora Energy's cost to serve (CTS) as that used in the 2022 Determination. In particular, the Regulator had decided to:

- use a cost build-up methodology together with benchmarking information to assess Aurora Energy's CTS;
- apply an efficiency factor; and
- adjust the CTS for inflation for each year other than the first year of the regulatory period.

The Regulator has also decided to:

- remove the adjustment mechanism that accounts for changes in customer numbers;
- further consider the treatment of cloud-based software costs during the price investigation; and
- require Aurora Energy to submit its cost allocation manual at the same time as it lodges its submission in relation to the pricing investigation.

5.1 Background

Aurora Energy's CTS accounts for the operating costs it incurs in providing retail services to small customers under standard retail contracts. Aurora Energy's CTS currently includes costs relating to:

- billing and revenue collection;
- marketing;
- providing advice and answering customer queries via its customer call centre;
- the aurora+ app;
- corporate overheads;
- allowance for bad debts; and
- regulatory compliance.

The current CTS allowance is expressed as a dollar per customer amount.

5.2 What other regulators do

The purpose of benchmarking is to test Aurora Energy's proposed CTS figure against CTS allowances for retailers in other Australian jurisdictions. Prior to the commencement of a pricing investigation, it also provides an opportunity to review the methodologies used by other regulators in the NEM.

Previously, the Regulator has benchmarked Aurora Energy's proposed CTS against the Australian Competition and Consumer Commission's (ACCC) Inquiry into the National Electricity Market Reports and investigations by the ICRC, AER and ESC. When benchmarking, it is important to acknowledge that each regulator has slightly different methodologies and approaches to allocating costs, so care must be taken in making direct comparisons.

The approaches taken by other regulators are discussed below.

ICRC

The ICRC has released its final price direction for the 2024-27 regulatory period. It estimates customer weighted average retail operating costs using data from the three largest retailers operating in the ACT. However, due to the small sample size, accuracy of data concerns and commercial in confidence considerations, ICRC cross-checks the retail operating costs of ActewAGL (the regulated retailer) against those reported by the AER in its Default Market Offer (DMO), as well as the ESC's decision on the Victorian Default Offer (VDO). ActewAGL's retail operating costs are adjusted by CPI each year.

ESC

Under the ESC's cost stack framework, retail costs are comprised of retail operating costs and customer acquisition and retention costs. Retail operating costs are calculated as the weighted average of Victorian retailers' actual operating costs, using data from the previous two financial years, adjusted for inflation. Regarding customer acquisition and retention costs, the ESC uses the ACCC's 2013-14 retail and electricity pricing inquiry as a benchmark, also adjusted for inflation, with the ACCC's inquiry considered to be more robust than the retailer customer acquisition and retention data.

QCA

The costs of supplying electricity in regional Queensland are much greater than in south-east Queensland (SEQ). For this reason, the Queensland Government implemented the Uniform Tariff Policy (UTP), which is a subsidy to ensure that customers in regional Queensland do not pay more for electricity than customers in SEQ. QCA sets prices based on the cost of supplying small customers (residential and small business) in SEQ which is an unregulated competitive market. This arrangement benefits regional customers, who would otherwise incur much greater prices for electricity.

QCA takes a different approach to setting notified prices compared with other regulators. Its methodology is broadly split in two - a network component and a retail component. To ensure consistency with the UTP, standard retail tariff costs for small customers are based on the competitive Energex distribution area of SEQ. The retail component is comprised of energy costs (wholesale electricity costs, Renewable Energy Target and energy losses), metering services and retail costs (operating costs and a retail margin). Both energy and retail costs are assessed by consultants ACIL Allen.

The QCA does not separate retail operating costs (i.e. CTS) and the retail margin. The Regulator is therefore unable to make use of the QCA's methodology when setting Aurora Energy's CTS.

AER

The AER's DMO applies to the NEM regions in South-east Queensland, South Australia and New South Wales. From the AER's 2024-25 final decision, retail costs include CTS, cost to acquire and retain customers, smart meter costs and bad and doubtful debt costs. These retail costs are summed in a 'cost stack' methodology. In order to estimate CTS, cost to acquire and retain customers and bad and doubtful debt components, the AER referred to the ACCC's Inquiry into the National Electricity Market - December 2023 report.

5.3 Draft Methodology Paper

In its Draft Methodology Paper, the Regulator proposed taking a similar approach in calculating Aurora Energy's CTS as that used for the 2022 Determination. In particular, the Regulator proposed:

- continuing to use a cost build-up methodology together with benchmarking information to assess Aurora Energy's CTS;
- applying an efficiency factor across all CTS components; and
- adjusting the CTS for inflation for each year other than the first year of the regulatory period.

However, the Regulator also proposed some changes to the current approach including:

- removing the adjustment mechanism that takes account of changes in customer numbers (under this mechanism, Aurora Energy's per customer CTS increases if Aurora Energy's customer numbers decline as there would be fewer customers to recover fixed costs from and decreases if customer numbers increase ie there are more customers to recover fixed costs from);
- further considering the treatment of cloud-based software costs including decisions made by other regulators with respect to these costs; and
- requiring Aurora Energy to implement a cost allocation manual prior to the pricing investigation.

The Regulator invited feedback on the proposed approach.

5.4 Consultation feedback

Cost build-up approach and benchmarking information

Aurora Energy broadly supported the approach that was used in the 2022 Determination. That is, to continue to use a cost build-up methodology together with benchmarking information to assess Aurora Energy's CTS.

The TSBC also broadly supported the Regulator's approach.

Efficiency factor

Aurora Energy did not support the use of an efficiency factor for the 2025 Determination. It noted the challenges of continual improvements in efficiency, the recent plateau in the average CTS across the National Electricity Market (NEM), as well as the increases in competition in the retail electricity market.

TSBC supported the use of an efficiency factor, stating that it would be an effective way to lower the CTS component.

Adjustment mechanism for customer numbers

Aurora Energy did not support the removal of the customer number adjustment mechanism. It noted that there are conceptual differences between its intended tariff re-balancing and the inclusion of a customer adjustment mechanism. It argued that its costs remain largely fixed in nature and there is little reason to remove the mechanism.

TSBC supported the removal of the adjustment mechanism, having regard to the expected outcomes from Aurora Energy's tariff rebalancing and because other regulators do not include such a mechanism.

During a meeting with consumer groups, one attendee considered that the adjustment mechanism should be removed.

Treatment of cloud-based system costs

Aurora Energy considered that cloud-based software costs should continue to be treated as operational expenditure because costs associated with the software are most accurately recovered this way; this is the approach prescribed under accounting standards; and this approach is in line with what other regulators do.

TSBC considered that cloud-based software costs should be treated as capital expenditure and noted that this would spread the costs over the life span of the system.

During a meeting with consumer groups, attendees considered Aurora Energy should be required to justify that cloud-based software is the most efficient way of procuring IT infrastructure and to demonstrate that cloud-based software is the most appropriate format in terms of ensuring the security of sensitive customer information.

Cost allocation manual

Aurora Energy has submitted a draft version of its cost allocation manual for the Regulator's consideration.

TSBC noted that it would prefer separation of Aurora Energy's regulatory accounts from its competitive retail business accounts, instead of a cost allocation manual. It stated that a cost allocation manual does not provide sufficient transparency between Aurora Energy's regulated and unregulated business.

Tasmanian retail electricity data

TSBC supported the use of data from Tasmanian retailers and considered that such data would provide an additional point of comparison to ensure Aurora Energy's costs are efficient.

5.5 Regulator's approach

For the 2025 standing offer pricing investigation, the Regulator has decided to continue to use a cost build-up methodology and benchmarking information to calculate Aurora Energy's CTS allowance.

Having considered the submissions, the Regulator has also made decisions on a number of specific issues in relation to the CTS calculation. These are discussed further below.

Efficiency factor

Given the significant reductions in retailer costs per customer in mainland Australia in recent years, the Regulator can see no reason why an efficiency factor should not be applied to Aurora Energy's CTS allowance as a way of incentivising Aurora Energy to continue to identify cost reductions. An efficiency factor should account for potential future cost savings due to increases in productivity.

The size of the efficiency factor will be determined during the price investigation.

Adjustment mechanism for customer numbers

The Regulator has decided to remove the mechanism from the CTS methodology. It is expected that Aurora Energy will recover a greater proportion of its fixed costs through its intended tariff rebalancing.

The Regulator has also made this decision based on the fact that, to date, retail competition has had little impact on Aurora Energy's market share which has meant, in turn, that the two per cent threshold for the mechanism to be activated has not been crossed during the past three years. Further, other regulators do not use such a mechanism.

Treatment of cloud-based system costs

The treatment of cloud-based system costs will be further investigated during the 2025 investigation. The Regulator notes the Essential Services Commission of South Australia in the *SA Water Regulatory 2024 Final Decision* has treated these costs as capital expenditure in its current regulatory period as a way of placing downwards pressure on prices, but intends to treat these expenses as operational expenditure in future periods.

Cost allocation manual

The Regulator considers that it is unclear whether the benefits of requiring Aurora Energy to prepare separate regulatory accounts would outweigh the costs of doing so.

However, the Regulator considers that there is merit in requiring Aurora Energy to prepare a detailed cost allocation manual, the purpose of which is to ensure greater transparency and consistency when allocating costs between regulated and unregulated sections of its business. This will be increasingly important, with Aurora Energy recently introducing market retail contracts to small customers.

In this regard, the Regulator has decided to require Aurora Energy to submit, at the same time as it lodges its pricing investigation submission, a revised manual that explains in detail the processes Aurora Energy applies in ensuring that costs relating to Aurora Energy's unregulated activities are not met by regulated customers. The Regulator will examine Aurora Energy's approach to allocating costs between the regulated and unregulated sections of its business as part of the upcoming investigation.

Tasmanian retail electricity data

The Regulator will continue to benchmark Aurora Energy's CTS allowance with non-Tasmanian retailers in the NEM, due to Aurora Energy's large market share and commercial in confidence considerations. If the market share of other retailers continues to grow, the Regulator may consider comparisons with other Tasmanian retailers in future investigations.

6 RENEWABLE ENERGY TARGET COSTS

Regulator's decision:

The Regulator has decided to continue to use the current approach to forecasting renewable energy target (RET) costs. Under this approach, Aurora Energy's long-term contractual commitments under the Cattle Hill Power Purchase Agreement (PPA) will be included in Aurora Energy's cost allowance for Large-scale Generation Certificates (LGCs).

6.1 Background

The NMR includes an estimate of the annual costs of Aurora Energy complying with the Australian Government's RET Scheme.

The Scheme creates a guaranteed market for renewable energy, using a mechanism of tradeable certificates with each certificate representing one-megawatt hour of renewable electricity generated.

Electricity consumers pay for this government requirement through obligations imposed on purchasers of wholesale electricity (including retailers) which then pass through the cost of complying with the obligations to customers.

The RET is made up of two schemes:

- the Large-scale Renewable Energy Target (LRET); and
- the Small-scale Renewable Energy Scheme (SRES).

Electricity retailers must purchase and surrender a specific number of LGCs each year. The number of LGCs to be surrendered each calendar year is calculated using the Renewable Power Percentage (RPP) which is determined by the Clean Energy Regulator (CER).

Small-scale Technology Certificates (STCs) must be purchased by electricity retailers. The number of STCs that retailers must purchase and surrender over the course of each calendar year is calculated using the Small-scale Technology Percentage which is also determined by the CER.

6.2 What other regulators do

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.

ICRC

The ICRC applies a market-based approach for determining efficient LRET and SRES costs. The ICRC's model determines LGC and STC prices based on publicly available spot price data averaged over a 12-month period to the end of April. The ICRC then applies the CER's RPP and STP percentages to the forecast prices and holding costs to the forecast customer load. The ICRC uses the CER's RPP for the first half of the calendar year and then estimates the RPP for the second half.

The Commission's pricing model operates on a financial year basis. LRET and SRES costs for a financial year are therefore derived by apportioning calendar year costs based on the half-yearly load weights provided by the regulated retailer, ActewAGL.

In addition to the timing of the LRET and SRES costs, the ICRC also includes a green scheme certificate holding cost in its pricing model, which is calculated by estimating the cost of debt. This is because retailers typically buy certificates in advance to manage price volatility and to avoid being unable to purchase enough certificates to meet their obligations.

QCA

QCA uses a consultant, currently ACIL Allen, to estimate LRET costs using a market-based approach. Under this approach, LGC prices are based on forward prices for certificates provided by broker TraditionAsia. ACIL Allen uses the CER's RPP for the first half of the price period and estimates the RPP for the second half of the price period.

ACIL Allen estimates SRES costs using the STP for the first half of the price period and the latest available non-binding STP for the second half of the price period. STC prices were based on the clearing house price of $40 per certificate as historically the spot prices have been at or close to this price.

The QCA only allows for an adjustment to the small-scale renewable energy scheme due to the binding small scale technology percentage for the second half of the financial year not being published at the time the prices are set. The QCA uses forward large-scale generation certificate energy prices in setting prices and makes no further adjustment on these.

ESC

The ESC has a separate environmental cost component that includes the cost of complying with the LRET and the SRES. The ESC uses a market-based approach to estimate LRET costs. The applicable market price for LGCs is determined by taking 12-month volume-weighted average of LGC forward trades for each year as reported by Demand Manager, an energy broker. The ESC uses the CER's RPP for the first half of the calendar year and then estimates the RPP for the second half.

To estimate the SRES, the ESC uses the binding STP and the most recent non-binding STP. The ESC uses the clearing house price of $40 per certificate.

6.3 Draft Methodology Paper

The Regulator proposed continuing to use the 2022 Determination approach to forecasting RET costs. Under this approach, Aurora Energy's long-term contractual commitments under the Cattle Hill PPA were included in Aurora Energy's cost allowance for LGCs. The forward price for the remaining LGCs in the relevant year were estimated as the average weekly forward LGC price over 12 months of the previous year.

6.4 Submissions

Aurora Energy commented that in the 2022 Determination, a full market approach presented a material risk to its Cattle Hill PPA as there was limited time to mitigate potential impacts before the Determination was to take effect. Since then, it commented that there have been significant changes in the LGC market with increased demand from corporate, commercial and industrial sectors to meet renewable claims. As a result, it considered that the risks of moving to a full market-based approach would be mitigated.

Aurora Energy stated that a shift to a full market-based approach is in the interests of both customers and the broader market due to a reduction of costs based on current forward market prices; the alignment of RET costs with other jurisdictions; and the promotion of competition by setting RET costs that are attainable through the market.

TSBC expressed concern over the inclusion of LGCs purchased by Aurora Energy under its PPA with Cattle Hill in the 2022 Determination. It considered that, in a competitive market, Aurora Energy would not be able to pass on the RET costs under its PPA and would have to absorb these costs.

TSBC has also sought a response from the Regulator in relation to the impact on standing offer prices from inclusion of the Cattle Hill PPA.

6.5 The Regulator's approach

The Regulator notes that both Aurora Energy and TSBC support a market-based approach to forecasting RET costs.

However, the Regulator recognises that retailers that are wholly exposed to RET prices under spot prices or short-term contracts may pay more for LGCs than under a longer-term contract. The Regulator also acknowledges that PPAs enable retailers to manage these financial risks and understands that many retailers enter into PPAs for this reason. It would also not be good practice to change regulatory approach mid-way through a PPA.

The Regulator has therefore decided to continue to include Aurora Energy's long-term contractual commitments under its Cattle Hill PPA when calculating Aurora Energy's LGC costs.

In relation to TSBC's query regarding the impact on standing offer prices from including the Cattle Hill PPA, the Regulator considers that the overall impact on standing offer prices can only be assessed at the completion of the PPA i.e. no meaningful comparison can be made other than in retrospect when the agreed prices are compared to market prices across the term of the agreement.

7 METERING COSTS

Regulator's decision:

The Regulator has decided to continue to use the current method for calculating metering costs including the current rollout rate of advanced meters.

The Regulator has decided to refine the method for calculating the proportion of regulated customers on various tariffs.

7.1 Background

Metering costs comprise the costs associated with the installation, maintenance and reading of meters, and costs associated with the introduction of metering competition and fee-based metering services.

Under the NER, retailers are responsible for engaging a Metering Coordinator for their small customers. Metering Coordinators and the services they provide are not price regulated. The NER also requires that any new or replacement meter must be an advanced meter.

There are numerous meter types used which can be broadly split into two groups:

- Basic accumulation meters. These are analogue meters which measure the total electricity consumed over a period and require manual reading; and
- Advanced meters, which record usage in real time and are read in 15- or 30-minute intervals. These meters are also able to record usage against multiple tariffs and can be read remotely.

Following the Tasmanian Liberal Party's commitment in 2021[5] to replace all accumulation meters in Tasmania with advanced meters by 2026, the remaining installations are expected to occur by December 2026. From discussions with Aurora Energy, these remaining installations are expected to be more difficult, due to some of these properties being in remote locations and the prevalence of asbestos in some switchboards.

7.2 What other regulators do

The treatment of metering costs differs between jurisdictions as set out in the following sections.

[5] The Tasmanian Liberal Party made a commitment before the May 2021 election to accelerate the rollout of advanced meters in Tasmania by 2026.

AER

In May 2024, the AER released its final determination for retail electricity default market offers in New South Wales, South Australia and South East Queensland. The AER includes advanced meter costs as a component of retail costs for its DMO determination.

Retailers in NSW, South Australia and South East Queensland are responsible for managing advanced meter installation and maintenance costs. The AER seeks advanced meter cost data directly from retailers.

ICRC

On 23 May 2024, the ICRC released its final report and price direction following the completion of its 2024-27 retail electricity price investigation for the ACT.

The 2024-27 price direction continues the same treatment of metering costs as the 2020 price direction. The approach spreads the cost of advanced meters across the total base of small electricity customers rather than charging individual customers for installation and meter reading (the same approach as currently adopted by the Regulator). This approach was based on fairness and equity considerations.

To estimate advanced meter costs, the ACT's electricity retailer and advanced meter installer, ActewAGL, provides an annual forecast of the weighted average cost per advanced meter and a forecast of the number of advanced meters. The ICRC expects that advanced meter costs will increase as the accelerated rollout continues.

Prior to its 2020 price direction, the ICRC did not include the costs of advanced meters in its electricity pricing model.

QCA

As outlined in its final determination released on 7 June 2024, the QCA includes small customer metering service costs in the retail cost component of customer tariffs. Metering costs are based on metering and advanced metering services and the installation rate for advanced meters in regional Queensland.

ESC

The ESC does not include a separate cost component for metering when determining its annual VDO. This is because electricity distribution businesses in Victoria are required to install advanced meters for all small customers. As a result of past policies, advanced meters have been compulsory in all Victorian homes and businesses since 2006. To recover the cost of metering (which includes meter reading and other on-going costs), the AER approves Victorian distribution network businesses charging retailers for advanced meters on a per customer basis. Metering costs are therefore factored into the network cost component for retailers.

7.3 Draft Methodology Paper

The Regulator proposed using the same approach for calculating metering costs as used for the 2022 Determination, but sought feedback on the potential slowdown of the rollout rate of the remaining advanced meters and also on refining the method to calculate the proportion of regulated customers on various tariffs.

7.4 Submissions

Aurora Energy considered that the current arrangement for the recovery of metering costs and the rollout of advanced meters should be maintained. It commented that it is obligated to uphold the commitment to complete the rollout by end of 2026 to its Ministerial Shareholders. It also considered that the continued rollout of advanced meters would enable it to take advantage of the operational efficiencies of the advanced meter and there would be a reduction in the risk of forecasting unders and overs once the rollout has been completed.

TSBC commented that while slowing down the rollout of advanced meters would put some downward pressure on standing offer prices, the cost saving would be small and it would also delay some small businesses gaining access to potentially beneficial time-of-use tariffs.

During a meeting with consumer groups, one attendee considered that the rollout of advanced meters should be slowed down because the rollout is entering a period when the existing meters are more difficult to replace. On the other hand, another attendee considered that the meter rollout should not be slowed down because this would embed inequity.

COTA commented that since the rollout of advanced meters, metering costs have grown substantially. COTA also considered that there is a need for significant pressure to be placed upon metering providers to better control their costs. It also considered that advanced meter technology should deliver efficiencies in the electricity system, not just add to consumer costs.

7.5 The Regulator's approach

Having considered the submissions, the Regulator accepts that the estimated cost saving from a slowdown of the advanced meter rollout would be small and that, while the potential benefit to customers from receiving an advanced meter is difficult to measure, it should not be overlooked. Therefore, the Regulator has decided to continue to use the current method to calculate metering costs including the current rollout rate of advanced meters.

In relation to concerns over the substantial increase in metering costs, the Regulator notes that the costs to supply and install advanced meters are subject to contractual arrangements between Aurora Energy and its metering providers. Aurora Energy uses a competitive public tender process when selecting providers, but the Regulator has no control over the outcome of these negotiations. In addition, advanced meters on a per unit basis are more expensive than accumulation meters.

The Regulator will ensure that metering costs are appropriately apportioned between regulated customers and market customers during the pricing investigation.

The Regulator also notes that under the 2022 Determination, metering costs were allowed to be recovered for capital expenditure required to meet the set-up costs associated with the start of metering competition. As this arrangement has ended, Aurora Energy will not be able to recover any of these metering costs during the next regulatory period.

8 RETAIL MARGIN

Regulator's decision:
The Regulator has decided to continue to apply a benchmarking approach to setting a retail margin.
The Regulator has also decided to further consider the method for calculating the retail margin during the pricing investigation.

8.1 Background

The retail margin is intended to compensate Aurora Energy for the risks it faces providing retail services to customers on standard retail contracts. The retail margin is included in Aurora Energy's NMR and is therefore ultimately reflected in standing offer prices approved by the Regulator.

In the 2022 Determination, the Regulator used a benchmarking approach in setting the retail margin. This took into account the risks that Aurora Energy may face in Tasmania compared with retailers operating in other jurisdictions, including energy price risk and volume-related wholesale electricity price risk.

The retail margin was calculated on a dollar amount per customer basis in the 2022 Determination.

8.2 What other regulators do

The following is a summary of arrangements in other jurisdictions.

ICRC

The ICRC has previously used a benchmarking approach when determining a retail margin and expressed this as a percentage of costs. However, in its final determination for 2024-27, it has used a different approach.

The ICRC engaged Frontier Economics to examine a benchmarking approach and an expected returns approach to assess an appropriate retail margin. The key objective of the expected returns approach is to estimate the minimum retail margin required to compensate equity investors in a notional electricity retailer for the systematic or non-diversifiable risk (such as economic, political, or social risks) that they bear when committing equity capital to the firm.

Frontier Economics also explored the impact of using either a percentage margin or a fixed dollar margin. It considered that a retail margin as a percentage ignores that increasing energy costs reduce the risk faced by the retailer and so overcompensates the retailer, whereas a constant margin as a dollar amount ignores that some fixed costs have increased so that the retailer is undercompensated as energy costs increase. Frontier Economics concluded that a hybrid approach, giving equal weight to both the percentage margin and the dollar margin, appears to provide appropriate compensation.

The ICRC decided to implement the margin using a 50:50 weighting for the percentage and dollar amount. 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 only using a percentage margin.

ESC

In its final decision for 2024-25, the ESC determined to keep using a regulatory benchmarking approach to setting the retail margin and to keep the same margin (5.3 per cent of costs) that was applied in 2023-24. To ensure that the margin was still appropriate, the ESC considered the following factors:

- margins set by other Australian regulators;
- a comparison of Victorian market offer prices relative to VDO prices between 2019 and 2023;
- analysis prepared by Frontier Economics on the expected returns approach; and
- Victorian retailers' actual margins and actual margins of retailers operating in the NEM as presented in the ACCC's Inquiry into the NEM.

QCA

The QCA's model does not have a specific allowance for a retail margin. Rather, the QCA's approach focuses on estimating an efficient total level of retail costs, which implicitly includes some retail margin.

AER

In its final determination for the 2024-25 DMO, the AER estimated an 'efficient margin' by using a number of different approaches, including:

- inferring margins from advertised offers available between 1 July 2023 and 31 August 2023;
- inferring margins within the ACCC's findings of the actual retail prices charged to customers on 1 August 2023;
- assessing historical trends in individual retailers' actual margins and incurred costs reported to the ACCC as part of its retail electricity market inquiry; and
- benchmarking retail margin determinations in other jurisdictions.

The AER engaged ACIL Allen to assist with this work including assessing the relative merits of the methodologies and conducting the analysis based on advertised offers.

The AER also received a range of views on whether the margin should be calculated as a percentage of the DMO price or as a fixed dollar amount. Most retailers considered that the retail margin should be a percentage, to ensure that it moves relative to retailer risk. In contrast, the NSW Energy Minister held concerns that a percentage approach would exacerbate price increases; the South Australian Department for Energy and Mining commented that the AER should focus the DMO on the objective of protecting customers; and retailer Energy Locals supported a fixed dollar retail margin as it would give retailers greater certainty. Having considered the feedback, the AER has decided to continue to calculate the margin as a percentage of the DMO price.

8.3 Draft Methodology Paper

In the Draft Methodology Paper, the Regulator proposed to continue to apply a benchmarking approach to setting a retail margin that takes into account:

- the retail margins set by other regulators;
- Aurora Energy's risks compared to the risks facing retailers operating in other Australian states and territories; and
- the ACCC's Inquiry into the National Electricity Market.

The Regulator also sought comments from stakeholders on whether the margin should continue to be calculated on a dollar amount per customer basis or if a hybrid approach is more appropriate.

8.4 Consultation feedback

Benchmarking

Both Aurora Energy and TSBC supported a benchmarking approach to help set the retail margin.

Aurora Energy's risks

Aurora Energy considered that its risks are, overall, highly commensurate with those faced by other retailers. It considered that 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, Aurora Energy's risks are lower than other retailers. That said, Aurora Energy also commented that it is up to retailers to select their wholesale purchasing approach and the Regulator does not have a role in mandating what this approach should be.

Aurora Energy stated that, given the increasing competition in the Tasmanian retail electricity market, the pressure to bring efficiencies to costs and the volatile nature of recent outputs of the NEM, it is difficult to quantify risks compared to other retailers.

TSBC considered that:

- There is extensive regulation of the WEP in Tasmania and the method used is well known to Aurora Energy and very stable, such that it can adopt strategies to manage this and reduce risks. Retailers elsewhere in the NEM face much higher price risk.
- Aurora Energy also faces lower volume risk due to its dominant share of the small customer market. Although the number of retailers operating in the small customer segment has increased, their respective market shares remain low and all are Tier 2 retailers i.e. Aurora Energy faces no competition from any of the 'Big Three' retailers.

- Several other risks are worth mentioning such as an ability to recover overs/unders, regulatory approval of material and tax changes within regulatory periods and inclusion of the costs of Aurora's long-term PPA with the Cattle Hill wind farm in its renewable energy obligation costs.

Retail margin as a fixed dollar amount or as a combination of a fixed amount and a percentage of costs

Aurora Energy is concerned that the retail margin calculated in 2022 was undertaken with reference to (what were then) low wholesale cost periods and an overall lower cost stack. It noted that while the Regulator allowed a 5.25 per cent margin, this percentage was then applied to the most recent cost stacks at the time to convert the margin into a dollar amount per customer allowance. Aurora Energy therefore considered that this approach locked in a margin that was based on low wholesale costs. Instead, Aurora Energy considered that the period in which the cost stacks are applied to the margin percentage should reflect a consistent view of the market across periods.

Aurora Energy considered that the use of a fixed dollar amount margin is inadequate for reflecting the risks it faces. It considered that a fixed dollar margin required estimates of future costs which are highly uncertain. It considered that this can result in windfall losses (if actual costs are greater than forecast costs) or gains (if actual costs are less than forecast costs).

As an alternative approach, Aurora Energy considered that the ICRC's approach of adopting a 50:50 weighting for a fixed dollar amount and a percentage of costs would result in a more balanced handling of risk and certainty. It considered that such a hybrid approach would compensate retailers for systematic risk as wholesale energy costs rise or fall.

TSBC supported the current approach adopted by the Regulator to keep the retail margin allowance per customer constant, avoiding the margin being impacted by changes in costs. It also considered that the current approach improves the transparency of the costs associated with the retail margin.

During a meeting with consumer groups, one attendee commented that the methodology for the retail margin is not the issue, rather the size of the margin is the issue to address.

8.5 Regulator's approach

After considering the submissions and arrangements in other jurisdictions, the Regulator has decided to continue to apply a benchmarking approach to setting a retail margin that takes into account:

- the retail margins set by other regulators;
- Aurora Energy's risks compared to the risks facing retailers operating in other Australian states and territories; and
- the outcomes from the ACCC's Inquiry into the National Electricity Market.

In relation to Aurora Energy's risks compared to the risks facing retailers in other jurisdictions, the Regulator acknowledges TSBC's point that Aurora Energy faces no competition from any of the 'Big Three' retailers. Further, the Regulator notes that, to date, no other retailers in

Tasmania are competing on price. In effect, standing offer prices are a type of reference price that other retailers price off.

Having considered stakeholder views on the method for calculating the retail margin, the Regulator has decided to further consider this matter during the pricing investigation.

A method for calculating a retail margin will be set out in the Regulator's draft investigation report and draft determination.

9 OTHER COSTS

Regulator's decision:

The Regulator has decided to continue with its current approach to estimate NEM, Full Retail Contestability (FRC) electricity and ancillary service fees and to also use the current approach to calculate adjustments.

The Regulator has also decided to further consider the treatment of unaccounted for energy during the pricing investigation.

There are some other smaller cost components that are included in the NMR cost stack. Each of these cost components are discussed below.

9.1 AEMO costs

AEMO's operating costs are funded through annual fees levied on market participants. Retailers are liable to pay a portion of these fees.

Under the current approach, the Regulator estimates the AEMO fees Aurora Energy incurs to participate in the NEM and for FRC electricity[6] each year of the regulatory period using the customer numbers from the NTB, the DLF and the fees as determined by AEMO, and allows Aurora Energy to recover these costs from customers through standing offer prices.

Similarly, the Regulator estimates Aurora Energy's ancillary service fees[7] by multiplying the average monthly rate of ancillary fees ($/MWh) based on a 12-month period prior to April in the year immediately before the price period by the forecast small customer load in the NTB adjusted by the Distribution Loss Factor (DLF). As for AEMO fees, the Regulator allows Aurora Energy to recover these costs from customers through standing offer prices.

No submissions were received on these cost components.

The Regulator has therefore decided to continue with its current approach to estimating NEM, FRC electricity and ancillary services fees.

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6 FRC fees are intended to facilitate retail market competition by managing and supporting data for settlement purposes, customer transfers, business to business processes, and the implementation of market procedure changes.

7 AEMO is responsible for ensuring that the power system is operated in a safe, secure and reliable manner. In fulfilling this obligation, AEMO controls key technical characteristics of the power system such as frequency and voltage and system restarts through the ancillary services market. The NER provide for AEMO to recover a proportion of these costs from retailers.

9.2 Adjustments

The standing offer prices to apply to the next financial year are currently calculated using a NMR calculated in May / June of each year. Some NMR components such as wholesale electricity costs are already known for the next period at the time prices are calculated, while other components are not known and are based on estimates.

For NMR components based on estimated values, Aurora Energy may either under recover or over recover its costs based on the prices charged during a price period, depending on how actual costs vary from estimated costs.

The NMR may also include adjustments relating to the impact of tax events or material changes in Aurora Energy's costs as specified under Regulations 12 and 16 of the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2023*.

No submissions were received on this cost component.

The Regulator has therefore decided to continue with its current approach to calculating adjustments.

9.3 Unaccounted for energy

Unaccounted for energy (UFE) is the difference between metered energy entering a local area and the metered energy consumed within that local area. UFE occurs due to a number of factors including energy theft, inaccurate or faulty meters, estimation errors associated with unmetered devices, profiling of reads to the trading interval level or errors in the DLF.[8]

Since the introduction of global settlements in April 2022, all retailers commenced being billed by AEMO for UFE within their respective distribution areas. AEMO allocates UFE to retailers based on their accounted for energy.

In its Draft Methodology Paper, the Regulator sought further information and views from stakeholders on the treatment of UFE.

9.3.1 Submissions

Aurora Energy considered that the Regulator should allow for the recovery of costs associated with UFE. It suggested that UFE costs could be recovered through the allowance for AEMO fees or could be directly passed-through with a one-year lag (i.e. actual UFE costs in 2025-26 could be recovered in prices for 2026-27).

TSBC considered that Aurora Energy should not receive an allowance for UFE and that Aurora Energy should be incentivised to minimise the volume of UFE. It also considered that Aurora Energy is already compensated for this risk through the retail margin. However, should a UFE allowance be included in the calculation of standing offer prices, TSBC considered that the Regulator should ensure that Aurora Energy minimises the costs of UFE to its standing offer customers.

8 AEMO, UFE Fact Sheet (10 October 2022)

In a meeting with consumer groups, one attendee considered that the treatment of UFE depends on who has control over it. Another attendee considered that Aurora Energy should be responsible for the costs associated with UFE so that it is incentivised to manage this issue.

COTA commented that it would be inappropriate to increase consumer charges to account for UFE where consumers have no ability to control this cost.

9.3.2 Regulator's approach

The global settlements approach has only been in place since 2022 and, at this point in time, there is limited data available on the potential impact of UFE on standing offer customers. The Regulator will therefore consider the treatment of UFE further during the pricing investigation.

10 AURORA ENERGY'S TARIFF STRATEGY

Regulator's decision:

The Regulator has decided that Aurora Energy will be required to submit a draft Standing Offer Tariff Strategy that relates to the regulatory period that will be covered under the 2025 Determination.

10.1 Background

As part of previous price investigations, the Regulator has required Aurora Energy to submit a Tariff Strategy. The purpose of the Tariff Strategy is to set out the changes Aurora Energy intends making to its existing tariff structure during the next regulatory period.

Under the ESI Act, the Regulator has statutory objectives to promote competition and protect the interests of consumers of electricity. The Regulator does not prescribe which tariffs Aurora Energy may or may not offer to its customers. However, the Regulator will not approve a Tariff Strategy if it considered the tariffs being offered to customers or the changes proposed to be made to the tariffs are not in customers' best interests.

10.2 Draft Methodology Paper

The Regulator proposed continuing to require Aurora Energy to submit a draft Tariff Strategy.

While the Regulator noted that Aurora Energy would also be consulting on its Tariff Strategy, the Regulator was keen to seek initial views from stakeholders and, in particular, views on tariff rebalancing and whether there is an ongoing need for simpler tariffs.

10.3 Submissions

Aurora Energy commented that it is in the process of preparing a Tariff Strategy for the upcoming regulatory period. It noted that it has already consulted with stakeholders on the formulation of its Strategy which will include a review of recent drivers for change to standing offer tariffs (such as network pricing); the potential to introduce new tariffs and rebalancing of tariffs.

TSBC considered that if tariff rebalancing adds to small business electricity costs, it may support measures such as the use of side constraints to limit or slow these impacts on small business. However, it would first need to see how Aurora Energy's pricing strategy develops.

TSBC also commented that Aurora Energy should consider improving information to small business customers and consider introducing a retail tariff based on the demand-based network tariff (TAS88).

Consumer groups commented that:

- Aurora Energy should introduce a demand-based tariff;
- a flat rate tariff should be made available for new customers;
- information to customers should be presented in a basic format;
- there should be some guarantees for customers to ensure that Aurora Energy or other retailers are not marketing products that make customers worse-off; and
- Aurora Energy should be able to show on customers' bills if they could be better off if they were on a different tariff.

10.4 Regulator's approach

The Regulator requires Aurora Energy to submit a draft Tariff Strategy and intends publishing it for consultation.

In particular, the Regulator is keen to ensure that suitable tariffs are available to customers for the next regulatory period.

11 PRICE APPROVAL PROCESS

Regulator's decision:

The Regulator has decided to continue with an annual price approval process supported by an annual standing offer price approval guideline.

The Regulator has also decided to publish the WEP and Aurora Energy's draft annual pricing proposals as soon as practicable after calculation and receipt respectively.

11.1 Background

Under sections 40 and 41 of the ESI Act, Aurora Energy must obtain the Regulator's approval before fixing its standing offer prices and is not permitted to amend those prices unless approved by the Regulator.

In the 2022 Determination, the Regulator adopted an annual approval process supported by a standing offer price approval guideline. The guideline sets out the information that Aurora Energy must provide in its annual standing offer pricing proposals. It also details the obligations of Aurora Energy and the Regulator regarding the approval of prices for each pricing period, consistent with the provisions outlined in the ESI Act.

11.2 Draft Methodology Paper

In its Draft Methodology Paper, the Regulator proposed continuing to use an annual price approval process supported by a standing offer price approval guideline.

The Regulator also proposed that the guideline require Aurora Energy to consult with stakeholders on any tariff rebalancing proposals and side constraints prior to the Regulator approving standing offer prices. The Regulator also proposed publication the WEP once calculated and Aurora Energy's draft pricing proposal as soon as practicable.

The Regulator sought stakeholder feedback on its proposals.

11.3 Submissions

TSBC supported the Regulator's intention to publish the WEP and Aurora Energy's draft pricing proposal prior to approval of standing offer prices. TSBC commented that the Regulator should consider providing an explanatory statement and stakeholder feedback on the WEP and allow for stakeholder comment on Aurora Energy's pricing proposal.

11.4 Regulator's approach

The Regulator has decided to continue with an annual price approval process as supported by a standing offer price approval guideline. The Regulator intends imposing a new obligation in the guideline requiring Aurora Energy to consult annually with stakeholders with respect to any intended tariff rebalancing and any side constraints and to set out the outcomes from consultation in its annual pricing proposals.

Further, the Regulator has decided to publish the WEP once it has been calculated. The Regulator will also publish Aurora Energy's draft pricing proposal as soon as practicable after receipt.

While the publication of the WEP and Aurora Energy's draft pricing proposal will improve transparency of the annual price approval process, the Regulator notes that with Aurora Energy's pricing proposal not submitted until the end of May each year, there is insufficient time to consult on the proposal prior to the Regulator's consideration and subsequent approval of the proposal by mid-June so as the new prices can apply by 1 July. Consistent with past practice, the Regulator intends publishing a final version of Aurora Energy's proposal in mid-June.

12 LENGTH OF REGULATORY PERIOD

Regulator's decision:
The Regulator has decided to set the length of the next regulatory period at three years.

12.1 Background

There is no specific statutory requirement for the Regulator to set the duration of the regulatory period until making the determination, which must specify both the commencement and expiry dates.

In the determinations made since 2007, the duration of each regulatory period has been set at three years, including the 2022 Determination. However, due to the impacts of the COVID-19 pandemic, the State Government extended the expiry date of the 2016 Determination to 30 June 2022, resulting in a regulatory period of six years.

12.2 Draft Methodology Paper

The Regulator sought feedback on whether the next regulatory period commencing on 1 July 2025 should be of three or four years duration.

12.3 Submissions

Aurora Energy considered that there is a material level of costs involved in preparing for and undergoing a price investigation. It considered that a four-year period would allow for greater certainty of prices for customers and more time to focus on retail service outcomes.

Consumer groups also expressed a preference for a four-year period, which they considered would reduce the amount of work to be done by the Regulator, Aurora Energy and other stakeholders. One attendee also noted that if a four-year period was adopted for the upcoming regulatory period, it would end in 2029, making it possible to have the timing of future retail electricity regulatory periods align with TasNetworks' network regulatory period.

TSBC supported a three-year period. It considered that a three-year period would align well with the changes that are experienced in the wholesale, renewable energy and retail markets, whilst still providing a reasonable degree of regulatory certainty. In comparison, TSBC considered that a four-year period would not be as responsive to market changes and would still not align exactly with the five-year network regulatory period.

Solstice Energy supported a three-year period. It considered that a shorter period would allow for a better consideration of the rapidly evolving energy market and infrastructure development.

12.4 Regulator's approach

The Regulator acknowledges that there are costs and benefits arising from relatively shorter or longer regulatory periods. Given the uncertainty around the future impacts of retail competition in Tasmania, high rates of technological change, changing tariff structures and a number of large-scale energy projects for the State, the Regulator has decided to set the next regulatory period at three years.

ATTACHMENT 1: GLOSSARY

Term	Meaning
ACCC	Australian Competition and Consumer Commission
Adjustment mechanism	A mechanism whereby Aurora Energy's CTS on a per customer basis increases if Aurora Energy's customer numbers decline (as there would be fewer customers to recover fixed costs from) and decreases if customer numbers increase ie there are more customers to recover fixed costs from.
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Aurora Energy	Aurora Energy Pty Ltd, ABN 85 082 464 622
CER	Clean Energy Regulator
CPI	Consumer Price Index
DLF	Distribution Loss Factor
DMO	Default Market Offer, as determined by the AER
Economic Regulator Act	*Economic Regulator Act 2009*
ESC	Essential Services Commission, Victoria
ESI Act	*Electricity Supply Industry Act 1995*
FRC	Full Retail Competition
Grandfathering	From a point in time, allowing customers on certain tariffs to remain on those tariffs while not offering those tariffs to new customers.
Guideline	Guideline - Standing Offer Price Approval Process in accordance with the 2022 Standing Offer Electricity Price Determination (29 April 2022)
Hydro Tasmania	Hydro Electric Corporation ABN 48 072 377 158

ICRC	Independent Competition and Regulatory Commission, Australian Capital Territory
LGC	Large-scale Generation Certificate
Load	Electricity consumed by electricity users
Load Following Swap	One of the types of financial contracts Hydro Tasmania is required to offer to retailers. The Regulator is required to use the LFS price in estimating Aurora Energy's WEP and, consequentially, its WEC.
LRET	Large-scale Renewable Energy Target
Mainland Tasmania	All parts of Tasmania other than any off-shore island of Tasmania (except for Bruny Island)
Market retail contract	A contract between a retailer and a small customer who decides not to remain on a standard retail contract. Terms and conditions in market retail contracts can vary from contract to contract.
MLF	Marginal Loss Factor
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory period	The regulatory period commencing on 1 July 2025
NMR	Notional Maximum Revenue. The Regulator allows Aurora Energy to recover its NMR through its standing offer prices. That is, by applying the prices under each tariff to the billing days and load relating to the forecast number of customers under that tariff, a notional amount of annual revenue is calculated for each tariff. The total of these notional annual revenues for all tariffs must not exceed the Notional Maximum Revenue.
NTB	Notional Tariff Base. The NTB comprises the customer numbers and loads for all small customers

	connected to the distribution network that are eligible to take supply under a regulated tariff.
Price approval process	The process under which a regulated offer retailer submits its proposed standing offer prices for the Regulator's approval
Price period	A 12-month period from 1 July to 30 June (e.g., Period 1, Period 2, Period 3) to which Aurora Energy's annual pricing proposal and the Regulator's associated price approval relate.
Pricing Regulations	*Electricity Supply Industry (Pricing and Related Matters) Regulations 2023*
QCA	Queensland Competition Authority
Regulated offer retailer	An authorised retailer who is declared to be a regulated offer retailer in accordance with an order made under section 38B(1) of the ESI Act
Regulated tariff	A tariff to which a standing offer price, as approved by the Regulator, applies
Regulator	The Tasmanian Economic Regulator, appointed under the Economic Regulator Act
Regulatory period	The total period to which a determination relates (typically several price periods)
RET	Renewable Energy Target
Small customer	All residential customers and small business customers using less than 150MWh of electricity per annum
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificate
STP	Small-scale Technology Percentage
Standard retail contract	A contract under which a regulated offer retailer provides standard retail services to small customers. The retailer is unable to change the terms and conditions set out in a standard retail contract. A small customer electing not to enter into a market retail contract with a retailer receives supply under a standard retail contract.

Standard retail services	Services provided by a regulated offer retailer under standard retail contracts in respect of small customers
Standing offer price approval guideline	The guideline issued by the Regulator following each price investigation that sets out Aurora Energy's and the Regulator's obligations in relation to the submission, and approval, of annual price proposals
Standing offer prices	The standing offer prices, fixed, or amended under section 40 of the ESI Act. Standing offer prices are approved by the Regulator under section 41 of the ESI Act.
Standing Offer Price Strategy	Document setting out Aurora Energy's intentions with respect to, among other things, the structure of its tariffs and rebalancing of its tariffs during the upcoming regulatory period.
TasNetworks	Tasmanian Networks Pty Ltd, ABN 24 167 357 299
VDO	Victorian Default Offer, as determined by the ESC.
WEC	Wholesale Electricity Cost
WEP	The Wholesale Electricity Price is estimated by the Regulator based on wholesale contract prices generated by the Wholesale Pricing Model in accordance with the requirements of the Wholesale Contract Regulatory Instrument using a method set out in the Regulator's standing offer price approval guideline.
Wholesale Contract Regulatory Instrument	The instrument containing the approvals made by the Regulator from time to time under section 43G(1) of the ESI Act and Regulation 20 of the Pricing Regulations, having taken into account the principles set out in section 43H of the ESI Act.
Wholesale pricing model	The model based on the requirements and criteria set out in the Wholesale Contract Regulatory Instrument that is used to calculate the weekly prices for each of the wholesale contract types approved by the Regulator.

ATTACHMENT 2: LEGISLATIVE FRAMEWORK

The Regulator regulates electricity prices that Aurora Energy may charge small customers under standard retail contracts in accordance with the requirements set out in the ESI Act. Under this Act, Aurora Energy proposes, and the Regulator considers for approval, standing offer electricity prices.

Periodic pricing investigations are conducted by the Regulator in accordance with the process set out in the Pricing Regulations.

Under Section 40AA of the ESI Act, the Regulator must determine the maximum prices that Aurora Energy may charge, or a method for determining those maximum prices. Further, under Regulation 12 of the Pricing Regulations, a price-regulated retail service price determination may be expressed in one or more of the following terms or manners:

(a) maximum prices or the maximum rate of increase or the minimum rate of decrease in maximum prices;

(b) average prices or average rates of increase or decrease in average prices;

(c) pricing policies or principles;

(d) by reference to a general price index, the cost of production, revenue, a rate of return on assets or any other factor;

(e) by reference to quantity, location or period of provision of the services to small customers under standard retail contracts;

(f) by reference to a maximum revenue; and

(g) any other terms the Regulator considers appropriate.

Section 40AB of the ESI Act requires the Regulator to estimate Aurora Energy's operational costs in providing standard retail services.[9] Section 40AB(2) specifies the components of Aurora Energy's operational costs that the Regulator must consider, including wholesale electricity costs, transmission and distribution costs, cost to serve and any other costs Aurora Energy incurs providing those services.

[9] These are the services provided by a regulated offer retailer under standard retail contracts in respect to small customers.

ATTACHMENT 3: LIST OF SUBMISSIONS AND MEETINGS

On 5 July 2024, the Regulator released its Draft Methodology Paper.

Submissions were received from:

- Aurora Energy
- Solstice Energy
- TasNetworks
- Hydro Tasmania
- Tasmanian Small Business Council (TSBC)
- Council on the Ageing (COTA)
- APA

OTTER also held meetings with:

- TSBC and Goanna Energy
- COTA
- Salvation Army
- Tasmanian Council of Social Service (TasCOSS)

The submissions and notes from the meetings are available on the Regulator's website at 2025 Standing Offer Investigation and Determination.