2022 STANDING OFFER ELECTRICITY PRICING INVESTIGATION

DETERMINATION OF MAXIMUM STANDING OFFER PRICES FOR SMALL CUSTOMERS ON MAINLAND TASMANIA

1 JULY 2022 TO 30 JUNE 2025

FINAL REPORT

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THE TASMANIAN ECONOMIC REGULATOR

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EXECUTIVE SUMMARY

The Regulator's Final Report and Price Determination set out its decisions that will determine how maximum electricity prices are set for residential customers and small business customers on mainland Tasmania during the 2022-23, 2023-24 and 2024-25 financial years.

The Regulator has taken a number of measures in the Final Report to ensure that any price increases are kept to a minimum and reflect efficient costs.

- The cost to serve allowance has been reduced from $172.54 per customer in Aurora Energy's original pricing proposal to $156.31 per customer, including aurora+ app costs (in 2020-21 dollars).
- From 1 July 2022, there will be no separate charge for the aurora+ app as these costs will be recovered from customers on regulated tariffs. The allowance for aurora+ app costs, including marketing and call centre costs, has been set at an average of $9.08 per customer ($2020-21).
- The Regulator has also applied efficiency savings to Aurora Energy's cost to serve allowance at 1.78 per cent for 2022-23 and 3.4 per cent for 2023-24 and for 2024-25. These efficiency savings reduce Aurora Energy's allowance by approximately $13 per customer over the regulatory period.
- For 2022-23, the retail margin has been reduced from 5.7 per cent of approved costs to a value based on 5.25 per cent of approved costs (plus aurora+ costs) in recent years. It is lower by $16.33 per customer than the amount originally proposed by Aurora Energy ($2020-21). It is also now a per customer allowance which does not fluctuate with changes in Aurora Energy's costs such as wholesale electricity and network costs.

These measures taken by the Regulator reduce Aurora Energy's allowed costs in 2022-23 below those originally proposed by Aurora Energy such that that electricity prices in 2022-23 will be almost two per cent lower than they would have been under Aurora Energy's original proposal. These allowances are discussed in further detail below.

Regulated electricity prices include wholesale electricity costs, network costs and Renewable Energy Target costs. These values are not determined by the Regulator and are not known at this point. For each year, electricity prices will be approved by the Regulator in the June of the previous year, when the prices of the major cost components are known.

Background

Regulated electricity prices are the maximum prices that Aurora Energy, as Tasmania's regulated offer retailer, can charge residential customers and small business customers using less than 150MWh of electricity per annum under standard retail contracts on mainland Tasmania (including Bruny Island). These regulated prices provide a safety net for small customers.

The current price determination for regulated electricity prices, the *Aurora Energy Pty Ltd 2016 Standing Offer Price Determination* (2016 Determination), expires on 30 June 2022. The Regulator is required to make a new price determination and has decided that it will cover a three year period from 1 July 2022 to 30 June 2025. Before making the new price determination, the Regulator is required to conduct a pricing investigation.

In February 2021, the Regulator released its Draft Report for public consultation. The Draft Report set out the Regulator's draft conclusions and findings. A Draft Determination, the *Draft 2022 Standing Offer Price Determination*, was also released for consultation. Seven submissions were received on the Draft Report. A copy of the Draft Report, Draft Determination and submissions can be found on the Regulator's website at [2022 Standing Offer Pricing Investigation].

After considering the issues raised in submissions, the Regulator's decisions that affect the maximum prices that Aurora Energy may charge small customers under standard retail contracts are set out in this Final Report. The *2022 Standing Offer Price Determination* has also been published. A copy of the Final Report and Price Determination can be found on the Regulator's website.

As with previous determinations and as set out in the Draft Report, the Regulator has decided to retain the 'building block' approach to set regulated prices. Under this approach, regulated prices are set to enable a retailer to recover efficient costs of supplying electricity to customers on standard retail contracts.

Aurora Energy's costs of providing retail services are:

- wholesale electricity costs (around 29 per cent);
- network costs (around 42 per cent);
- renewable energy target (RET) costs (around 9 per cent) ;
- metering costs (around 5 per cent);
- Australian Energy Market Operator (AEMO) costs (around 1 per cent);
- Aurora Energy's retail costs or cost to serve (around 8 per cent); and
- a retail margin (around 5 per cent).

Other inputs used in the calculations of these components are electricity loss factors, and forecast customer numbers and forecast total load.

The Regulator allows Aurora Energy to recover these costs in its standing offer prices. By examining all of Aurora Energy's costs, including allowances set by the Regulator, the Regulator seeks to ensure that customers pay no more than necessary for the services they receive.

Cost to serve

The cost to serve (CTS) allowance reflects the Regulator's assessment of the efficient level of Aurora Energy's operating costs to provide retail services to customers on standing offer prices. The Regulator has approved the inclusion of Aurora Energy's aurora+ costs in the CTS allowance, as proposed by Aurora Energy, so that the product is not separately charged to Aurora Energy customers.

Aurora Energy's retail costs include:

- billing and revenue collection;
- marketing;
- providing advice and answering customer queries;
- contributing to corporate overheads;
- the costs relating to aurora+ and
- regulatory compliance.

The Regulator has estimated Aurora Energy's CTS allowance per customer using a cost build-up approach and then tested the result against CTS allowances for retailers in other Australian jurisdictions. This involved conducting a detailed review of Aurora Energy's operating cost structure to calculate what the Regulator considers to be an efficient CTS value.

To inform the Regulator's draft assessment on Aurora Energy's CTS, it engaged Utilities Regulation Advisory (URA) and Oakley Greenwood (OGW) to review the robustness of Aurora Energy's forecasting approach and whether the estimates reflect efficient costs. A summary of the URA's/OGW's findings are available on the Regulator's website.

After considering the issues raised in submissions, the Regulator has decided to reduce the allowance for aurora+ costs from an average over the 2022-25 regulatory period of $14.15 per customer in the Draft Report to $9.08 per customer (expressed in 2020-21 dollars). This is substantially below the cost allowance proposed by Aurora Energy of $17.33 in its pricing proposal and of $14.15 in its submission to the Regulator's Draft Report. The reduction in the allowance is due primarily to lower marketing and call centre-related costs.

The Regulator has decided to include an efficiency factor in the CTS allowance of 1.78 per cent for 2022-23 and 3.4 per cent for 2023-24 and 2024-25. This will reduce the CTS allowance in each year from what it otherwise would be, resulting in the CTS allowance being around nine per cent lower in 2024-25 than without this efficiency factor.

The Regulator's decision is to set a CTS allowance in 2022-23 of $156.31 per customer (2020-21 dollars), including aurora+ costs. This allowance for Aurora Energy's CTS for 2022-23 is around $16.23 per customer lower than in Aurora Energy's pricing proposal and around $12.29 per customer lower than in its submission to the Regulator's Draft Report. It is around $7.96 per customer higher than the level in 2021-22, in 2020-21 dollars. The Regulator's CTS allowance for 2022-23 includes the efficiency factor.

These values are expressed in 2020-21 dollars. The actual CTS allowance for 2022-23 and the following two years will be adjusted to take into account the general increases in wages and other costs since 2020-21. For 2023-24 and 2024-25, if there is a more than two per cent change in customer numbers, the CTS will be adjusted to enable Aurora Energy to recover its fixed costs from a smaller or larger customer base.

Retail margin

The retail margin is intended to compensate Aurora Energy for the risks it faces providing standard retail services to its customers and also to recover depreciation costs.

The Regulator adopted a benchmarking approach to setting Aurora Energy's retail margin. In determining the retail margin, the Regulator considered the margins set in other jurisdictions and assessed whether Aurora Energy's risks were greater than the risks facing retailers operating in other Australian states and territories.

After considering the submissions from stakeholders, the Regulator has decided that a retail margin based on 5.25 per cent of approved costs (plus aurora+ costs) in recent years is appropriate. For 2022-23, the Regulator has set the allowance for the retail margin at $100.90 per customer (in current dollars). After allowing for indexation, this represents a decrease of $17.23 per customer from the retail margin in Aurora Energy's pricing proposal and a decrease of $10.75 per customer in its submission to the Regulator's Draft Report. In absolute dollar terms, the retail margin in 2022-23 will be almost identical to the retail margin in 2021-22.

The retail margin in 2023-24 and 2024-25 will be $100.90 indexed by changes in the Hobart CPI.

This is substantively unchanged from the decision set out in the Regulator's Draft Report, with the retail margin for 2022-23 now expressed in current dollars.

Wholesale electricity costs

Wholesale electricity costs are a significant component of the retail price of electricity. The Regulator has decided to calculate these costs for each year as follows:

$$WEC = (\text{Forecast load} \times WEP \times DLF \times MLF)$$

Where:

Forecast load	=	an estimate of the volume of electricity Aurora Energy will purchase in the spot market to supply small customers
WEP	=	wholesale electricity price as calculated by the Regulator using the method set out in the Standing Offer Price Approval Guideline
DLF	=	load weighted average distribution loss factor
MLF	=	load weighted average marginal loss factor at the regional reference node for Tasmania

Aurora Energy is responsible for estimating the annual load. The Regulator is required to calculate a WEP based on load following swap prices, which are in a financial hedge contract where the price per MWh is set and the volume in the contract is based on a specified load profile. In most years since 2014, the Regulator has calculated the WEP using a weighted average of load following swap prices and has decided to continue with this approach.

This is unchanged from the decision in the Regulator's Draft Report.

Network costs

Electricity retailers incur a number of costs over which they have no control and which they seek to recover in their prices to customers. Of these costs, network costs that Aurora Energy pays to TasNetworks are the most significant. TasNetworks' prices are regulated by the Australian Energy Regulator.

The Regulator has decided to continue to use the current approach to estimating network costs. That is, Aurora Energy's network costs are calculated 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 Regulator will require Aurora Energy to reconcile the billing days used in deriving network costs with the forecast of the customer numbers.

This is unchanged from the decision set out in the Regulator's Draft Report.

Renewable Energy Target costs

Electricity prices include an estimate of the annual costs of Aurora Energy complying with the Australian Government's Renewable Energy Target (RET) scheme.

The RET scheme has two elements:

- the Large-scale Renewable Energy Target; and
- the Small-scale Renewable Energy Scheme.

The large-scale scheme supports the development of large-scale projects such as wind farms. Electricity retailers must purchase and surrender a specific number of Large-scale Generation Certificates (LGCs) each year. The number of LGCs to be surrendered each calendar year is calculated using the Renewable Power Percentage, which is determined annually by the Clean Energy Regulator, and the quantity of electricity purchased by the retailer.

The small scale scheme supports investment in smaller technologies such as rooftop solar panels and solar hot water systems through the generation of Small-scale Technology Certificates (STCs). 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 annually by the Clean Energy Regulator.

These percentages are applied to the amount of wholesale electricity purchased by Aurora Energy for each calendar year. LGC and STC prices are determined in an open market.

To determine the cost allowance for LGC-related costs, the Regulator has decided to include the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill PPA for the relevant year, and an average forward price for the remaining LGCs.

In relation to STCs, the Regulator has decided to approve an allowance for STC costs based on Aurora Energy's estimate of the price in its costs for the relevant year, with some adjustments allowed in the following year for under or over recoveries.

Metering costs

Metering costs comprise the costs associated with the installation, maintenance and reading of meters, and the costs associated with the introduction of metering competition and fee-based metering services. These are pass through costs as Aurora Energy does not provide meter-related services.

The Regulator had decided to continue to use the current approach to calculating metering costs using a weighted average calculation of metering costs per tariff multiplied by the number of billing days. The Regulator has also decided to require Aurora Energy to reconcile billing days used in deriving metering costs with the forecast of the customer numbers.

This is unchanged from the decision set out in the Regulator's Draft Report.

AEMO costs

AEMO is a not-for-profit public company funded wholly by participant fees. AEMO operates the energy markets and systems and also delivers planning advice in the NEM. Retailers including Aurora Energy are liable to pay a portion of the fees levied by AEMO. The Regulator has decided to continue to provide Aurora Energy with an allowance for AEMO fees.

This is unchanged from the decision set out in the Regulator's Draft Report.

Under and over recoveries

Some cost components must be based on estimates, as the final values will not be known at the time standing offer prices are approved. The Regulator estimates these costs based on the most appropriate method, dependent on the cost component being estimated. These estimates may be higher or lower than the actual values once they become available.

Under and/or over recoveries will be limited to network costs, metering costs, AEMO charges and some RET costs, and apply only in cases where the relevant cost component per unit price is not known at the time prices are set for the next year.

In relation to STC costs, the Regulator has decided to allow the over and under recovery of STC costs due to price differences. That is, Aurora will receive the average actual prices it paid for STCs as it applies to all its load.

Other issues

In the interests of an open, public, transparent and fair process, it is desirable for as much information as possible to be made public. The Regulator has decided to review its confidentiality provisions prior to conducting the next pricing investigation in 2024-25.

The Regulator has also decided to examine the merits of requiring Aurora Energy to prepare separate regulatory accounts and activity-based costings prior to conducting the next pricing investigation in 2024-25.

Summary of key decisions

Table 1 below summarises the key decisions from the Regulator's Draft Report and this report.

Table 1: Summary of key decisions in the Regulator's Draft Report and Final Report

Component	Draft Report	Final Report
Cost to serve	The Regulator set the CTS allowance in 2022-23 of $156.42 per customer (2020-21 dollars), including aurora+ costs.	The Regulator to set a CTS allowance in 2022-23 of $156.31 per customer (2020-21 dollars), including aurora+ costs.
aurora+ costs	The Regulator allowed aurora+ costs of an average of $14.15 per customer (in $2020-21), over the regulatory period.	The Regulator allowed aurora+ costs of an average of $9.08 per customer (in $2020-21) over the regulatory period.
Platform and IT costs	The Regulator removed some operations and maintenance IT billing costs that related to the legacy billing platform (CC&B).	The Regulator included these costs as it is satisfied that billing costs of around this level would be incurred regardless of the billing system.
Efficiency factor	The Regulator applied an efficiency factor in the CTS allowance of 1.78 per cent for 2022-23 and 3.4 per cent for 2023-24 and 2024-25.	This decision is unchanged from the Draft Report.
Retail margin	The Regulator set the allowance for the retail margin in 2022-23 at $96.25 per customer (in $2020-21).	This decision is substantively unchanged from the Draft Report. The value in 2022-23 will be $100.90 per customer (current dollars).
Wholesale electricity costs	The WEP is to be calculated using a weighted average of eight quarters of load following swap prices under the Wholesale Contract Regulatory Instrument.	This decision is unchanged from the Draft Report.
Network costs	Network costs are to be calculated multiplying the applicable TasNetworks network tariff by forecast billing days and customer load for each retail tariff and then summing the resultant values.	This decision is unchanged from the Draft Report.
RET costs	The cost allowance for LGCs is to be calculated by using the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill PPA for the relevant year, and an	The decision in relation to LGC-related costs is unchanged from the Draft Report. The Regulator will approve an allowance for STC costs that enables Aurora Energy to recover its actual costs, using the average STC price

	average forward price for the remaining LGCs. Average forward prices for STCs will be used to calculate the cost allowance for STC costs.	that Aurora Energy pays for all its load, including from market contract customers.
Metering costs	Metering costs will be calculated using a weighted average calculation of metering costs per tariff multiplied by the number of billing days.	This decision is unchanged from the Draft Report.
Confidentiality provisions	-	The Regulator will review its confidentiality provisions prior to conducting the next pricing investigation in 2024-25.
Regulatory accounts and activity-based costing	-	The Regulator will examine the merits of requiring Aurora Energy to prepare separate regulatory accounts and activity-based costings prior to conducting the next pricing investigation in 2024-25.

1 INTRODUCTION

Section 40AA of the *Electricity Supply Industry Act 1995* (the ESI Act) requires the Tasmanian Economic Regulator to determine the maximum prices, or a method of determining the maximum prices, that Aurora Energy may charge small customers under standard retail contracts on mainland Tasmania (including Bruny Island).

The current price determination, the *Aurora Energy Pty Ltd 2016 Standing Offer Price Determination* (2016 Determination), expires on 30 June 2022. The Regulator is required to make a new price determination and has decided that it will cover a three year period from 1 July 2022 to 30 June 2025. Before making the new price determination, the Regulator is required to conduct a pricing investigation.

In September 2021, the Regulator released its *Retail Electricity Standing Offer Price Methodology Review Paper* (Approach Paper) which set out the methodology that the Regulator intended to apply during the pricing investigation.

In February 2021, the Regulator released its Draft Report for public consultation. The Draft Report set out the Regulator's draft conclusions and findings. A Draft Determination, the *Draft 2022 Standing Offer Price Determination*, was also released for consultation. Seven submissions were received on the Draft Report. A copy of the Draft Report, Draft Determination and submissions can be found on the Regulator's website at 2022 Standing Offer Pricing Investigation.

After considering the issues raised in submissions, the Regulator's decisions that affect the maximum prices that Aurora Energy may charge small customers under standard retail contracts are set out in this Final Report. Further, the *2022 Standing Offer Price Determination*, has also been published. A copy of the Final Report and Determination can be found on the Regulator's website.

1.1 Matters to be considered

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.[1] Under this Act, Aurora Energy proposes, and the Regulator considers for approval, standing offer electricity prices under a range of tariffs offered by Aurora Energy.

Price investigations are conducted by the Regulator in accordance with the process set out in the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2013* (Pricing Regulations).

Section 40AB of the ESI Act requires the Regulator to estimate Aurora Energy's costs in providing standard retail services. Section 40AB(2) specifies the components of Aurora Energy's operational costs that the Regulator must consider, comprising wholesale

1 Small customers are all residential customers and small business customers using less than 150MWh of electricity per annum.

electricity costs, transmission and distribution costs, cost to serve and any other costs Aurora Energy incurs providing those services.

Further, section 6(2) of the ESI Act specifies that, in exercising powers and functions under the Act, the Regulator is to promote efficiency and competition in the electricity supply industry and protect the interests of consumers of electricity.

1.2 Tasmanian context

The structure of the Tasmanian electricity market is significantly different from the market in other jurisdictions on mainland Australia. Compared to mainland Australia, Tasmania has some major industrial customers that account for a relatively large share of electricity consumption. Residential and small business customers therefore account for a much smaller share of total electricity consumption compared to the situation in other Australian jurisdictions.

Over 90 per cent of electricity generated in the State is produced by entities fully or partly owned by the State Government. The major generator, Hydro Tasmania provides around 85 per cent of all on-island electricity generation. TasNetworks, which operates the State's transmission network and the distribution network, is also State-owned. Aurora Energy, also a State-owned company, is the major retailer and currently has around 96 per cent of residential customers and 95 per cent of small business customers.[2]

As a result of Hydro Tasmania's dominance in electricity generation in the State, the ESI Act includes regulation of some of Hydro Tasmania's wholesale electricity financial risk contracts. Hydro Tasmania is required to offer certain financial risk contracts that are approved by the Regulator. These contracts are available to all retailers operating in Tasmania. The Australian Energy Regulator (AER) is the economic regulator for TasNetworks while the Regulator monitors TasNetworks' performance against a number of non-price criteria.

Since full retail competition was introduced into mainland Tasmania on 1 July 2014, retailers other than Aurora Energy have been able to offer products to residential customers and small business customers. The entry of new retailers into the Tasmanian market (particularly the residential sector) has been relatively recent with 1st Energy entering the residential customer market in early 2019. Since then, other retailers have entered the residential market.

Regulated prices provide a safety net price for small customers and are the maximum prices that Aurora Energy can charge small customers, except in cases where Aurora Energy sells electricity under market contracts. Aurora Energy currently does not offer any market contracts to residential customers but does sell electricity to some small business customers under market contracts.

Aurora Energy offers a range of tariffs to residential and small business customers that are regulated, including time-of-use tariffs such as Tariff 93 and Tariff 94 and tariffs designed for particular customers, such as its irrigation time-of-use tariff (Tariff 75).

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2 Based on data reported by retailers operating in Tasmania to the Australian Energy Regulator for the second quarter of 2021-22 (combined customer numbers for customers on standard retail contracts and customers on market offer contracts).

1.3 Consultation process

In August 2020, the Regulator decided to review the methodology to be used in determining Aurora Energy's standing offer prices. In April 2021, the Regulator released its draft Retail Electricity Standing Offer Price Methodology Review Approach Paper which set out the Regulator's intended approach for the 2022 price investigation. Nine submissions were received on the draft Approach Paper. Copies of the draft Approach Paper and submissions can be found on the Regulator's website and is available here: Draft Approach Paper.

In September 2021, the Regulator released its Approach Paper. The Approach Paper includes the Regulator's responses to the issues raised by stakeholders during consultation on the draft Approach Paper, which is available here: Approach Paper.

In February 2021, the Regulator released its Draft Report for public consultation. The Draft Report set out the Regulator's draft conclusions and findings. A Draft Determination, the *Draft 2022 Standing Offer Price Determination*, was also published. Seven submissions were received on the Draft Report.

On 3 March 2022, the Regulator provided a presentation on its Draft Report to the OTTER Customer Consultative Committee (OCCC) and received a range of comments from OCCC members. A further meeting involving OCCC members and OTTER staff was held later in March 2022 which provided opportunity for OCCC members to provide additional comments on the Draft Report.

1.4 Next steps

In May each year, Aurora Energy is required to submit its proposed standing offer prices for the following financial year. The Regulator will assess Aurora Energy's pricing proposal against the 2022 Price Determination, which sets out how Aurora Energy's maximum prices standing offer prices are to be calculated from 1 July 2022 until 30 June 2025. The Regulator will approve Aurora Energy's standing offer prices for the following year, which may be different from Aurora Energy's initial proposal, once it is satisfied they comply with the 2022 Price Determination.

2 APPROACH TO SETTING MAXIMUM STANDING OFFER PRICES

Regulated prices are set at a level that enables a retailer to recover the costs of supplying electricity to customers on standard retail contracts.

The costs of providing retail services are:

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

Other inputs used in the calculations of these components are loss factors, and forecast customer numbers and forecast total load (together the latter two inputs are referred to as the Notional Tariff Base).

The Regulator adopts a 'building block' approach under which these costs are summed to arrive at a total value of forecast costs for the year. Some of these costs are set by other processes, such as network costs that are approved by the AER, while other costs are approved by the Regulator, such as the cost to serve and the retail margin.

The Regulator allows Aurora Energy to recover these costs in 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 aggregate of this calculation for all tariffs must not exceed the Notional Maximum Revenue or NMR.

The NMR is calculated solely for the purpose of setting maximum prices, based on a set of assumptions including customer numbers and the volume of electricity sold (load) for that 12 month period. Aurora Energy's actual total costs, and revenue, will be different, one reason for which is that customers numbers and load cannot be predicted with 100 per cent accuracy. The Regulator does not set any cap on Aurora Energy's actual total revenue. For these reasons, the revenue level set for pricing purposes only is described as notional.

By examining all of Aurora Energy's costs, including allowances set by the Regulator, the Regulator seeks to ensure that customers pay no more than necessary for the services they receive.

As set out in the Regulator's Draft Report, the Regulator's approach is generally similar to the approach in the 2016 Determination. However, the retail margin will be set as a dollar amount per customer rather than as a percentage of total costs as under the 2016 Determination.

2.1.1 Calculating the NMR

The formula for the cost build-up method of determining maximum standing offer prices is:

$$NMR_y = WEC_y + NC_y + RET_y + M_y + CTS_y + AEMO_y + MARGIN_y + K_y + A_y + CF_y$$

where:

y	=	the relevant financial year, eg Year 1, 2 and 3.
NMR_y	=	the notional maximum revenue that Aurora Energy can receive and is calculated for each of periods 1, 2 and 3 during the annual standing offer price approval process.
WEC_y	=	the forecast of wholesale electricity costs and is based on the wholesale energy price (WEP), forecast load and distribution and marginal loss factors.
NC_y	=	forecast network costs. Network costs comprise two components: transmission and distribution charges.
RET_y	=	the forecast cost of Aurora Energy complying with the Australian Government's mandatory renewable energy schemes.
M_y	=	the forecast of allowed metering costs.
CTS_y	=	Aurora Energy's cost to serve.
$AEMO_y$	=	the total of Aurora Energy's forecast market participant fees and ancillary service charges, as set by AEMO.
$MARGIN_y$	=	the retail margin which reflects the risks Aurora Energy incurs in providing retail services to small customers under standard retail contracts.
K_y	=	an aggregate of approved under and/or over recoveries for network costs, metering costs, RET and AEMO costs under the 2022 Determination (and so only applying in years 2 and 3).

A_y = an adjustment made as a result of a tax event, a material change in circumstances or a material change in Aurora Energy's costs.

CF_y = an aggregate of under and/or over recoveries from the previous period covered by the 2016 Determination.

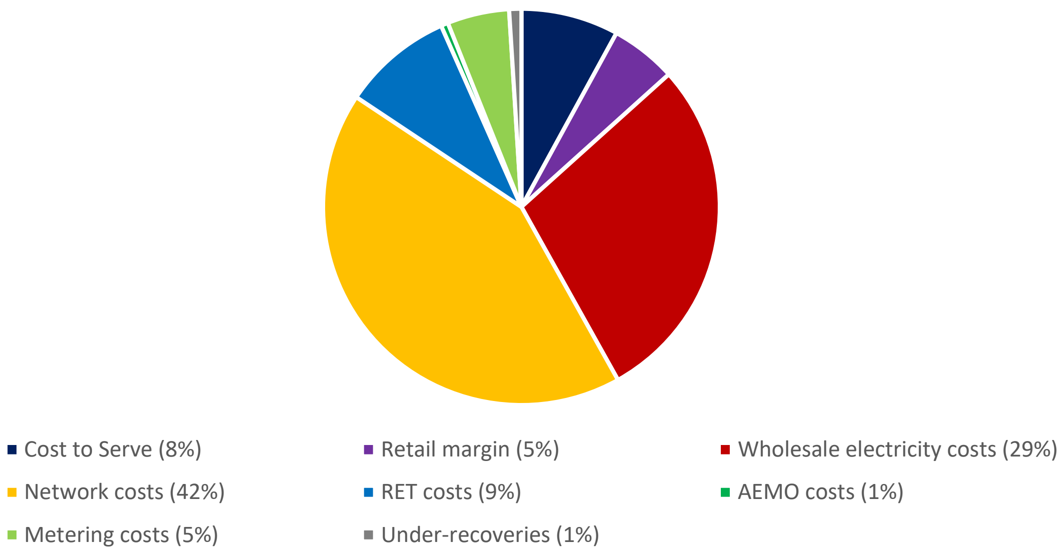
The Regulator has determined that the forecast of customer numbers will be the mid-point of actual customer numbers as at 31 March prior to the start of each year and a forecast of customer numbers as at 31 March during the year. Billing days, which refers to the number of days that a tariff is used by customers within a financial year, for network costs and metering costs will be reconciled to this forecast of customer numbers.

The Regulator has also determined that the load in the NTB will be a forecast of the total amount of electricity consumed by the forecast number of customers over the 12 month period from 1 April to the following 31 March.

2.1.2 Cost components in 2021-22

Figure 2.1 illustrates how each of the cost components contributed to Aurora Energy's NMR for 2021-22.

Figure 2.1 Cost components of Aurora Energy's NMR in 2021-22 (per cent)



For 2021-22, the NMR was $512 million. The largest cost components were network costs (42 per cent) and wholesale electricity costs (29 per cent).

3 WHOLESALE ELECTRICITY COSTS

Regulator's decision

The Regulator will continue to use the method outlined in the 2016 Determination to calculate wholesale electricity costs.

This is unchanged from the decision in the Regulator's Draft Report.

3.1 Background

Under the National Electricity Market arrangements, Aurora Energy buys its electricity from the Australian Energy Market Operator (AEMO) in the spot market for the Tasmanian region. Spot prices may be very volatile. Retailers would be exposed to unacceptable risks without entering into any hedging contracts with electricity generators.

Hydro Tasmania is the dominant generator in Tasmania and controls the majority of the generation capacity in the state. Hydro Tasmania is also the principal provider of financial hedge contracts for the Tasmanian region of the NEM. In response to perceptions about Hydro Tasmania's market power, the Tasmanian Government has, since 2014, required Hydro Tasmania to offer wholesale electricity financial risk contracts at regulated prices that are available to authorised retailers operating in Tasmania.

Hydro Tasmania is required to offer four financial risk contract types (load following swaps, baseload swaps, peak period swaps, and baseload caps) approved by the Regulator, with the objective of providing retailers in Tasmania with similar conditions and levels of risk and duration as available to retailers operating in other regions of the NEM.

The details of each approved financial contract type, including how prices are calculated, are specified in the *Wholesale Contract Regulatory Instrument* (Instrument). The Instrument documents a rules-based methodology for calculating the prices for each contract type. The Instrument produces weekly prices and specifies minimum volumes that Hydro Tasmania must offer for up to two years ahead. The Regulator approves these prices and monitors the weekly price offers.

As electricity flows through the transmission and distribution systems a portion is lost due to electrical resistance and the heating of conductors. Due to these losses the amount of electricity a retailer buys on the spot market must be greater than the volume or load it sells to its customers. To account for this difference the load is grossed up (multiplied) by loss factors.

The distribution loss factor (DLF) represents the average energy loss incurred when electricity is transmitted over the distribution network. Distribution Network Service Providers determine the DLFs to apply in each financial year, and, after approval from the AER, provide the DLFs to AEMO for publication. AEMO is required to publish DLFs, by 1 April each year, to apply to the following financial year.

The marginal loss factor (MLF) represents the average energy loss incurred when electricity is transmitted over the transmission network. AEMO determines and publishes MLFs for each NEM region in late May/early June each year to apply to the following financial year.

3.2 Draft Report

As set out in the Draft Report, the Regulator intended calculating the WEC as follows:

$$WEC_y = (\text{forecast load}_y \times WEP_y \times DLF_y \times MLF_y)$$

Where:

Forecast load_y	=	an estimate of the volume of electricity a retailer must purchase in the spot market to supply small customers for period *y*
WEP_y	=	wholesale electricity price for period *y* as calculated by the Regulator using the method set out in the Standing Offer Price Approval Guideline
DLF_y	=	load weighted average distribution loss factor for period y
MLF_y	=	load weighted average marginal loss factor at the regional reference node for Tasmania for period *y*

Under the ESI Act, the Regulator is required to calculate the WEC having regard to an approved load following swap contract. A load following swap contract is a financial hedge contract where the price per MWh is set and the volume in the contract is based on a specified load profile.

In most years since 2014, the Regulator has calculated the WEP using a weighted average of load following swap prices offered over the previous eight quarters (104 weeks). The WEP calculation method is set out in the Regulator's Guideline, titled *Guideline - Standing Offer Price Approval Process in Accordance with the 2022 Standing Offer Price Determination*. The WEP is determined in May each year prior to the commencement of the next financial year. This calculation was not required in years when a WEP Order was in place, which set the WEP the Regulator was to apply in calculating standing offer prices.

The Regulator considered that the current method reflects how retailers in other regions of the National Electricity Market might enter into financial risk contracts to hedge their spot market risk exposure.

The Regulator's decision was to continue to use the current method to calculate the WEP and therefore to not change the Guideline used for the 2016 Determination.

3.3 Submissions received

Aurora Energy supports the Regulator's intended approach and no other submissions raised any concerns.

3.4 Summary

The Regulator has decided to continue to use the method outlined in the 2016 Determination to calculate wholesale electricity costs.

This is predicated, however, on any future legislative changes not requiring the Regulator to adopt a different approach to setting the WEP as occurred during some years covered by the 2016 Price Determination when a WEP Order was in place.

4 NETWORK COSTS

Regulator's decision

The Regulator will continue to use the current approach to estimating 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 Regulator will also reconcile the billing days used in deriving network costs with the forecast of the customer, ie the billing days used when forecasting network costs are to relate directly to the forecast of customers numbers

These decisions are unchanged from the decisions in the Draft Report.

4.1 Background

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

Network costs are regulated by the AER. The AER conducts periodic pricing investigations into, and determinations of, network pricing. Each year, TasNetworks submits its annual price proposal for the AER's approval and the AER assesses whether the proposal aligns with the AER's determination. The AER approves tariffs to apply for 12 months from 1 July of each year and are usually set in April or May of the previous year. The current price determination for TasNetworks is for the period from 1 July 2019 to 30 June 2024.

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

4.2 Draft Report

The Regulator intended setting network cost component of Aurora Energy's NMR by multiplying the applicable TasNetworks' network tariff by forecast billing days and customer load for each retail tariff and then summing the resultant values.

If the charges are not known when the NMR must be calculated (eg if the AER has not approved TasNetworks' prices by that time), Aurora Energy's network costs will be based on an estimate of the charges, such as TasNetworks' draft price proposal for the upcoming year. In these circumstances, an adjustment will have to be made in the subsequent year if there is a difference between the estimated and the actual charges. This situation rarely occurs and adjustments are, therefore, generally not required.

4.3 Submissions received

Aurora Energy supports the intended approach and no other submissions raised any concerns.

4.4 Summary

The Regulator has decided to continue to apply the current approach to estimating network costs.

5 RENEWABLE ENERGY TARGET COSTS

Regulator's decision

To determine the cost allowance for LGC-related costs, the Regulator will include the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill PPA for the relevant year, and an average forward price for the remaining LGCs.

In relation to STCs, the Regulator will approve an allowance for STC costs based on Aurora Energy's estimate of the price in its costs for the relevant year, with some adjustments allowed in the following year for under or over recoveries.

5.1 Background

The NMR includes an estimate of Aurora Energy's annual costs of complying with the Australian Government's Renewable Energy Target (RET) scheme.

The scheme creates a guaranteed market for renewable energy, using a mechanism of tradable certificates with each certificate representing one-megawatt hour of renewable electricity generated. Electricity consumers pay for this Australian Government requirement through obligations imposed on retailers, which then seek to pass through the costs to customers.

The RET scheme has two elements:

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

The LRET supports the development of large-scale projects such as wind farms. Electricity retailers must purchase and surrender a specific number of Large-scale Generation Certificates (LGCs) each year. The number of LGCs to be surrendered each calendar year is calculated using the Renewable Power Percentage (RPP), which is determined annually by the Clean Energy Regulator (CER), and the quantity of electricity purchased by the retailer.

The SRES supports investment in smaller technologies such as rooftop solar panels and solar hot water systems through the generation of Small-scale Technology Certificates (STCs). 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 (STP) which is also determined annually by the CER.

The RPP and STP are applied to the volume of electricity purchased by the retailer in a calendar year. In March of each year, the CER publishes the final binding percentages for that calendar year for the RPP and the STP and also issues non-binding STPs for the following two calendar years.

This means that in April or May each year, a retailer cannot estimate with accuracy the quantity of LGCs it must purchase for the following financial year as the RPP is only known up to December in that year.

LGC and STC prices are determined in an open market. However, STCs can also be sold through the STC Clearing House for a fixed price, which is also the maximum price, currently at $40 per certificate (excluding GST).[3]

In summary, an electricity retailer's annual costs of complying with the RET are determined by the RPP, the STP, the price of LGCs and STCs and the quantity of electricity purchased by the retailer (the liable MWh).

5.2 Draft Report

The Regulator's intended formula for estimating LRET costs was as follows:

LRET cost = (RPP x $/LGC x liable MWh)

The Regulator intended setting the LGC price for each of the 2022-23, 2023-24 and 2024-25 financial years using a weighted price calculated on:

- the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill Power Purchase Agreement (PPA) for the relevant year; and
- the forward LGC price for the remaining volume of LGCs that Aurora Energy is required to purchase for the relevant year under the RET scheme.

In calculating the weighted LGC price for the relevant year, the proportion of LGCs purchased under the Cattle Hill PPA would be calculated as follows:

1. Forecast the percentage of its total LGC liability that will apply to the estimated load required to supply customers on standard retail contracts.
2. Apply the percentage calculated in 1 to the total number of LGCs purchased under the Cattle Hill PPA for that year to determine the number of LGCs to be included in the weighted LGC price.
3. Apply the average forward price for that year to the remaining LGCs required for the estimated load.

The forward price for the remaining LGCs in the relevant year is to be estimated as the average weekly forward LGC price over 10 months of the previous year (the average of forward LGC prices from the first Wednesday in July through to the last Wednesday in April). This would require Aurora Energy to source the weekly forward prices from an independent market based source, such as an energy broker.

3 The CER operates the STC Clearing House, which facilitates the exchange of small-scale technology certificates (STCs) between buyers and sellers. The STC Clearing House is accessible via the Renewable Energy Certificate Registry.

The intended formula for estimating the SRES costs was as follows:

Total SRES cost = (STP x $/STC x liable MWh)

In relation to STC prices, the Regulator intended applying a similar approach. That is, the forward price for STCs in the relevant year was to be estimated by Aurora Energy as the average of the weekly forward STC prices over ten months of the previous year (the average of forward LGC prices from the first Wednesday in July through to the last Wednesday in April).

As the LRET and SRET schemes operate on a calendar year basis, it was necessary to allocate the estimated annual liable MWh between the first half of the financial year (ie 1 July to 31 December) and the second half of the financial year (ie 1 January to 30 June). Under the 2016 Determination, to set the allowance the Regulator allocated the annual load in the proportions of 55:45 for the first and second half of the each financial year. As part of the calculation of over and under recoveries for RET costs, Aurora Energy's actual load proportions are used.[4]

In addition to the direct LGC and STC costs, the Regulator intended allowing Aurora Energy to recover brokerage and acquittal costs.

5.3 Submissions received

Two submissions were received on RET costs.

Aurora Energy

While Aurora Energy supports the Regulator's methodology for LGCs, it did not support the Regulator's proposal to apply the same approach to STCs on the grounds that there tend to be no contracts with forward prices offered beyond six months. Aurora Energy suggested using a hybrid STC methodology which included forward contract prices and the prevailing clearing house price for periods in the following year for which there are no forward prices.

COTA Tasmania

COTA Tasmania considers that RET costs will potentially fall disproportionately upon those least able to avoid them. It considers that these costs should be apportioned across all consumers in a manner which reflects their total household energy consumption, including consumption from solar PV systems and not just the amount of energy purchased from a retailer.

5.4 Discussion

STC prices

The Regulator does not support Aurora Energy's proposal to incorporate the clearing house price as this is a maximum price. In any STC purchasing strategy, Aurora Energy can only gain

[4] For example, if the early winter months (May and June) were particularly cold, the actual proportions could be closer to 50:50.

as its actual STC prices may be below, but cannot be above, the clearing house price. While Aurora Energy is encouraged to purchase STCs at the lowest cost, no benefit would be passed on to customers on standing offer prices. It also means the STC costs included in standing offer prices would likely be higher than in Aurora Energy's market contract customers.

The Regulator notes that no regulators set a STC allowance based on forward prices. Taking into account the issues identified around the forward price, the Regulator considers that the current approach of allowing Aurora Energy to recover the actual STC prices paid for all its load, including its market contract load, is appropriate. Approximately two-thirds of these costs are apportioned to standing offer customers.

This ensures that the same cost is allocated to market contracts and standard retail contracts. Aurora Energy has an incentive to keep these costs low as, in addition to facing increasing competition in the small customer segment, it faces much stronger competition in the larger customer segment.

On balance, the Regulator has decided to approve an allowance for STC costs using an estimate of the actual prices paid by Aurora Energy.

Under this approach, Aurora Energy would provide an estimate in May of the previous year and, through over and under recoveries, Aurora would receive the average actual prices paid for STCs as it applies to all its load. Over and under recoveries are discussed further in Chapter 10.

Apportioning RET costs based on household energy consumption

In response to COTA's proposal, the Regulator considers that apportioning RET costs based on total household energy consumption would not be possible as there are no data available on the volume of consumption by households or businesses from their solar PV systems or other renewable energy systems. Furthermore, the Regulator notes that Aurora Energy's liability under the RET scheme is a function of the electricity it purchases, not the total consumption of its customers.

5.5 Summary

To determine the cost allowance for LGC-related costs, the Regulator has decided to include the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill PPA for the relevant year, and an average forward price for the remaining LGCs.

In relation to STCs, the Regulator has decided to approve an allowance for STC costs using a price based on Aurora Energy's estimate of its actual purchases, with some adjustments allowed in the following year.

6 METERING COSTS

Regulator's decision

The Regulator will continue to use the current approach to calculating metering costs and also to require Aurora Energy to reconcile billing days used in deriving metering costs with the forecast of the customer numbers used in the NTB.

This decision is unchanged from the Draft Report.

6.1 Background

Metering costs comprise the costs associated with the installation, maintenance and reading of meters, and the costs associated with the introduction of metering competition and fee-based metering services. Metering costs are pass through costs as Aurora Energy does not perform any metering-related services.

Metering competition commenced on 1 December 2017. Under the national Power of Choice reforms, Aurora Energy has been required to engage at least one Metering Coordinator for its small customers since that date. The Metering Coordinator is responsible for providing metering services for customers for whom its meters are installed, and for managing service levels, rule compliance and performance reporting. Any new or replacement meter installed by the Metering Coordinator must be an advanced or interval meter.

There are currently two types of meters for Aurora Energy's customers and three parties/entities responsible for managing them who receive revenue from Aurora Energy for their services:

- Type 6 meters or accumulation meters, which are analogue meters that measure the total electricity consumed over a period and require manual reading. These meters are owned by TasNetworks, which is also responsible for reading these meters. Customers on Tariffs 31 and 41 (most residential customers are on this combination) are likely to have two Type 6 meters on their premises.
- Type 4 or interval meters, which are advanced meters that record usage in real time. These meters are also able to record usage against multiple tariffs and can be read remotely.
    - Aurora Energy appointed Yurika (previously Metering Dynamics) to manage the installation, maintenance and reading of Type 4 meters from 1 December 2017. Yurika continues to be responsible for all services relating to the Type 4 meters it installed between 1 December 2017 and 31 May 2021.
    - TasMetering was appointed as an additional Metering Coordinator from 1 June 2021 following the completion of a public tender procurement process. Since that time, all new meters are installed by TasMetering.

6.2 Draft Report

The Regulator's draft assessment was to allow Aurora Energy to use a weighted average calculation of metering costs per tariff multiplied by the number of billing days to forecast its metering costs.

The Regulator intended that Aurora Energy could recover the following metering costs:

- the aggregate of metering charges based on tariff, meter type and billing days for both accumulation and advanced meters.
- the ongoing annual capital cost associated with accumulation meters that have been replaced by advanced meters;
- depreciation associated with capital expenditure required to meet the set up costs associated with the start of metering competition (costs to be written off over 6 years commencing from 1 December 2017); and
- fee-based metering services recovered on an annual basis.

While the cost of an advanced meter is significantly higher than that of an accumulation meter, under Aurora Energy's tariffs, the prices to customers in these tariffs would be the same irrespective of the type of meter they have.

6.3 Submissions received

Three submissions were received on metering costs.

Aurora Energy

Aurora Energy supports the Regulator's intended approach.

COTA Tasmania

COTA Tasmania notes the rapid escalation of metering costs. In particular, it queries why capital expenditure on accumulation meters from a past period are included in costs for advanced meters. It also queries the distinction between aggregate metering charges and the costs associated with fee based metering services.

Further, COTA Tasmania considers that metering costs should be discounted by the benefits which are presumed to flow to Aurora Energy from the provision of advanced meters. It considers that there are many benefits to a retailer from having detailed hour by hour data across its total consumer base. These benefits, according to COTA, include the provision of energy products which lead to operational efficiencies for the retailer and an improved understanding of the aggregate demand for electricity which could be used to secure improved wholesale price arrangements.

TREA

TREA considers that advanced meters are an essential tool in the ability to move to a smarter grid, to provide customers with more information about their usage and to access new tariff types and use them effectively.

TREA recommends that the Regulator should seek an assurance from Aurora Energy that the advanced meter rollout will be completed as quickly as practicable and that Aurora Energy's cost to serve allowance includes sufficient resourcing for the education and support necessary to enable customers to access the benefits of advanced meters.

6.4 Discussion

As discussed in the Draft Report, metering costs are expected to increase over the regulatory period. This largely due to the anticipated increased rollout of advanced meters, including the installation costs and the higher cost, per unit, of advanced meters. Currently, around one third of Aurora Energy's residential customers have advanced meters. It is expected that by the end of the next regulatory period on 30 June 2025, the vast majority of Aurora Energy's residential customers will have advanced meters.

In accordance with the AER's distribution determination for the period 1 July 2019 to 30 June 2024, TasNetworks is permitted to recover the remaining capital costs associated with accumulation meters that have been replaced by advanced meters where they have a remaining useful life (ie depreciation).[5] As these costs are passed on by TasNetworks and therefore incurred by Aurora Energy, the Regulator considers that it is reasonable that an allowance be made for them.

Aggregate metering charges refer to the costs associated with the installation, maintenance and reading of meters while fee-based services are a separate cost that metering providers charge Aurora Energy. An example may be a remote site service surcharge for installing meters in remote locations. The Regulator considers that it is also reasonable that an allowance be made for these fee-based services.

In relation to whether metering costs should be discounted by the benefits that may accrue to Aurora Energy from the provision of advanced meters, the Regulator notes that an efficiency factor will be applied to Aurora Energy's cost to serve across the regulatory period. The efficiency factor is discussed further in Chapter 7.

As part of the annual price approval process, the Regulator will monitor the progress of the advanced meter rollout. The Regulator also considers that Aurora Energy's cost to serve allowance includes funds to provide the education and support activities required to enable customers to access the benefits of advanced meters.

6.5 Summary

The Regulator has decided, consistent with the Draft Report, to continue to use the current approach to calculating metering costs and also to require Aurora Energy to reconcile billing days with the forecast of the customer numbers in the NTB.

[5] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24

7 RETAIL COST TO SERVE

Regulator's decision

Aurora Energy's cost to serve (CTS) allowance for 2022-23 is $156.31 per customer (2020-21 dollars) which includes an efficiency factor of 1.78 per cent for that year. The actual CTS allowance for 2022-23 will be adjusted to take into account the general increases in wages and other costs since 2020-21.

For the second and third year of the regulatory period, consistent with the Draft Report, the Regulator has decided to adjust the CTS amount for each year by:

- including a mechanism to adjust the CTS to reflect changes in customer numbers;
- indexing Aurora Energy's labour cost components using changes in Tasmania's Wage Price Index (ABS CAT NO 6345.0) for;
- indexing for all non-labour cost components using changes in the Hobart Consumer Price Index (ABS CAT NO 6401.0); and
- applying an efficiency factor of 3.4 per cent for each year.

The Regulator has also decided to decrease Aurora Energy's CTS allowance relating to aurora+ from the level in the Draft Report by:

- decreasing Aurora Energy's allowance for call centre costs in relation to aurora+;
- decreasing Aurora Energy's allowance for marketing-related costs in relation to aurora+ to 25 per cent of the initial costs proposed by Aurora Energy; and
- removing Aurora Energy's proposed billing costs in relation to aurora+.

As a result of these changes, the allowance for aurora+ costs has been reduced from an average of $14.15 per customer over the 2022-23 to 2024-25 regulatory period in the Draft Report to an average of $9.08 per customer, in 2020-21 dollars. This includes the impact of the efficiency factors.

In the Draft Report, the Regulator deducted IT-related billing costs relating to the former billing platform, CC&B. The Regulator has decided to include these costs as is satisfied that billing costs of around this level would be incurred regardless of the billing system.

7.1 Background

The CTS allowance reflects the Regulator's assessment of the efficient level of operating costs for Aurora Energy to provide retail services to customers on standard retail contracts over the 2022-32 to 2024-25 regulatory period. These costs include:

- billing and revenue collection;
- marketing;

- providing advice and answering customer queries;
- contributing to corporate overheads;
- allowance for bad debt; and
- regulatory compliance.

7.2 Draft Report

The Regulator estimated Aurora Energy's CTS allowance by using a cost build-up approach and then tested the result against CTS allowances for retailers in other Australian jurisdictions. This involved conducting a detailed review of Aurora Energy's operating cost structure to calculate what the Regulator considers to be an efficient CTS figure.

To inform the Regulator's assessment, the Regulator engaged Utilities Regulation Advisory (URA) and Oakley Greenwood (OGW) to review the efficiency of Aurora Energy's proposed CTS.

The Regulator was satisfied that Aurora Energy's approach to developing its cost to serve forecasts was robust. Based on the Regulator's review of Aurora Energy's operational costs and URA's/OWG's findings, the Regulator's draft assessment was to reduce Aurora Energy's proposed CTS allowance by:

- applying an efficiency factor (1.78 per cent in 2022-23 and 3.4 per cent in 2023-24 and 2024-25) across all cost categories, including bad debts, contained in Aurora Energy's CTS. The efficiency factor is lower in the first year to reflect labour cost savings Aurora Energy had already applied in its pricing proposal (this equated to an efficiency gain 1.62 per cent);
- removing the COVID-19 adjustment for bad debts;
- decreasing marketing costs for the aurora+ app;
- removing the allowance for revenue protection and bad debts relating to aurora+;
- removing some costs that relate to Aurora Energy's previous billing system; and
- removing costs for unspecified projects.

Having reviewed Aurora Energy's operational costs, considered URA's/OGW's findings and examined arrangements in other jurisdictions, the Regulator's draft assessment was to allow a CTS allowance for Aurora Energy of $156.42 per customer in 2022-23 (in $2020-21) which includes the impact of the efficiency factor for that years. It also includes the Regulator's intended allowance for aurora+ costs of an average of $14.15 over the regulatory period. This compares with Aurora Energy's proposed CTS allowance of $172.54, which included costs relating to aurora+, which was estimated at an average of $17.33.

For the second and third year of the regulatory period, the Regulator's draft assessment was to adjust the CTS amount for each year by:

- adjusting the CTS to reflect changes in customer numbers;
- indexing Aurora Energy's labour cost components using changes in Tasmania's Wage Price Index;

- indexing all non-labour cost components using changes in the Hobart Consumer Price Index ; and
- applying an efficiency factor across all costs at 3.4 per cent for 2023-24 and for 2024-25.

7.3 Submissions received

The stakeholder submissions included the following points relating to Aurora Energy's CTS. As set out below, all stakeholders other than Aurora Energy consider that Aurora Energy's CTS should be lower than the level proposed by Aurora Energy and as set out in the Regulator's Draft Report.

Aurora Energy

Aurora Energy considers that its CTS in 2022-23 should be higher than in the Draft Report for the following reasons:

- The productivity/efficiency factors applied by the Regulator are significantly higher than in other recent regulatory decisions. Aurora Energy considers an ongoing efficiency factor should reflect more recent regulatory decisions which impose annual efficiency factors in the 0 - 0.5 per cent range.
- The removal of Aurora Energy's COVID-19 related bad debt allowance from 2022-23 and 2023-24 on the basis of Tasmania's broader economic performance is not reflective of the current state of customer debt levels in Tasmania. Aurora Energy considers that the age profile of customer debt continues to get older and that it is highly unlikely that the level of customer debt will return to pre-COVID-19 levels by 1 July 2022.
- Aurora Energy is in the midst of transitioning from its legacy billing platform (CC&B) to its new billing platform (HubCX). Aurora Energy states that 'the Regulator's decision to remove CC&B licence costs in isolation does not consider the offsetting increase in licencing costs associated with HubCX'.
- There are number of regulatory and compliance changes that Aurora Energy is required to manage (for example, Better Bills Guideline and Consumer Data Right) over the 2022 Determination period and an allowance for these activities in the CTS is needed.

Aurora Energy accepts the reduced allowance for aurora+ in the Draft Report. Based on the above points, Aurora Energy proposes a revised CTS of $168.60 per customer in 2022-23 ($2020-21) inclusive of the Regulator's intended allowance for Aurora+ costs of $14.15.

COTA Tasmania

COTA Tasmania considers that, in light of the very significant reductions in the CTS across Australia in recent years, the CTS allowance should be substantially lower than in the Regulator's Draft Report. The submission states:

- Aurora Energy's labour costs have risen by about 30 per cent between 2016-17 and 2020-21, while other retailers have seen their labour costs decline as much as 15 per cent over the same period. It considers that, if the CTS in 2022-23 is based on most recent allowance under the 2016 Determination (2021-22), an efficiency factor of between 8 to 10 per cent per year should be applied over the forthcoming Determination period to reflect the need for Aurora Energy to catch up with efficiency savings achieved by other retailers.

- If Aurora Energy had provided Aurora+ as its standard product offering earlier, Aurora Energy could have been more proactive in marketing the wide range of payment options available to consumers. By basing the draft Determination on the current level of bad and doubtful debts, COTA Tasmania considers that the Regulator is rewarding Aurora's strategic decision to not offer an app-based product as part of its standard offering.
- Aurora no longer has to provide its forms-based customer system which has a large manual handling component.

In relation to aurora+, COTA Tasmania fully supports the provision of Aurora+ as an integral element of the standard retail energy offering. However, COTA Tasmania questions the amount of additional revenues Aurora claims to need for aurora+ costs on the following grounds:

- aurora+ is just another information channel for customers to use.
- the reason why Aurora Energy is currently experiencing a relatively high cost associated with servicing aurora+ customers is because that cohort of customers who have taken up the product to date are those with the greatest interest in their electricity consumption. Therefore, COTA Tasmania does not consider the experience to date can be applied uniformly across the whole customer base.
- The Regulator needs to provide more justification in determining the cost allowance proposed for aurora+. It considers that the revenue requirement should be around $2 million per annum to support the development, maintenance, technology and access cost associated with aurora+. Therefore, it considers the cost per customer should be around $7 to $8 per annum.

Based on the analysis above, COTA Tasmania considers that:

- if the CTS in 2022-23 is based on the most recent allowance under the 2016 Determination (2021-22), an efficiency factor of between 8 to 10 per cent per year should be applied over the forthcoming Determination period;
- alternatively, the CTS should set at the outset between $132 to $137 per customer and the efficiency factors in the Regulator's Draft Report should then be applied.

TREA

TREA is generally supportive of the move to make the aurora+ app available to all customers without a separate charge. However, it has the following concerns:

- around half of the customers would face electricity bills that include the Aurora+ costs but would not be able to access the benefits of aurora+.
- the Aurora+ app does not currently support Tariff 22. TREA recommends that the Regulator should seek an assurance and a timeline from Aurora Energy for the aurora+ app to support Tariff 22 customers.

- Aurora Energy’s call centre costs may initially increase as customers learn how to access and use the aurora+ app and that anticipated savings may take longer to materialise.

Tasmanian Labor Party

The Tasmanian Labor Party considers that it is unfair and unjustified to include the aurora+ app in the CTS applied to all customers’ bills. This is because most customers who have been given the choice have already chosen not to use the app. It considers that this is likely for a variety of reasons, including a lack of time, interest, technological capability or because they cannot be flexible with the amount of power they use and when they use it.

The Tasmanian Labor Party considers that customers should not be forced to pay for an app they do not need or want. It is concerned that the proposed allowance would result in a revenue stream of approximately $3.8 million per year for Aurora which would be more than double Aurora’s current revenue from the app and will come directly from Tasmanian households and businesses at a time they can least afford it. Therefore, the Tasmanian Labor Party urges the Regulator to reconsider the treatment of the aurora+ app in its final determination.

TasCOSS/TSBC

TasCOSS/TSBC consider that Aurora Energy’s base CTS in 2022-23 should be lower for the following reasons:

- the Regulator’s intended efficiency factors of 1.78 per cent for 2022-23 and 3.4 per cent for the next two years have not been adequately justified. TasCOSS/TSBC consider that the 3.4 per cent efficiency factor should be applied in all years of the regulatory period.

- the intended allowance for Aurora Energy’s customer acquisition and retention costs (CARC) is excessive considering Aurora Energy has not experienced a sufficiently high level of retail competition. They recommend that no allowance for CARC should be provided in the Regulator’s Determination or, if an allowance is provided, the maximum allowance should be 15 per cent of the total CTS for customer retention.

- the Regulator should maintain national wage and price indices for use in calculating the CTS allowance, rather than moving to Tasmanian indices for annual CTS adjustments. TasCOSS/TSBC acknowledge that Tasmanian indices are likely to be more reflective of local factors, but argue that, as local indices have been increasing at a greater rate recently, applying these will add additional costs to small customers.

TasCOSS/TSBC also note that:

- Aurora Energy has relatively high numbers of customers in debt. Rather than providing an allowance in the CTS to cover debts, TasCOSS/TSBC consider that Aurora Energy should be incentivised to find ways to better manage and reduce its debt costs. Therefore, they support the Regulator’s proposed application of the efficiency factor to debt costs. Further, TasCOSS/TSBC also support the Regulator’s proposal to remove the COVID-19 debt premium given that such an allowance was temporary and the ESC and AER do not currently provide a COVID-19 debt allowance.

- As labour costs are a significant element of Aurora Energy's retail operating costs, TasCOSS/TSBC support the application of the efficiency factor to Aurora's labour costs.
- the URA/OGW report found that retail operating costs have fallen significantly for both large and small retailers.

TasCOSS/TSBC consider that the Regulator should put most weight on the recent ACCC benchmarks, which show a declining CTS and evidence of economies of scale. The ACCC report shows an average CTS in 2020-21 of $96 per customer for 'Big 3' retailers and $170 per customer for 'non-Big 3' retailers. On this basis, TasCOSS/TSBC consider that Aurora Energy's CTS for the next regulatory period be around $130-140 per customer.

TasCOSS/TSBC are supportive of aurora+ being included in the CTS and available to all customers, but note significant issues surrounding access. They consider that Aurora Energy or the State Government should facilitate energy and technology literacy courses.

TasCOSS/TSBC suggest that OTTER undertakes additional work to establish whether aurora+ costs are efficient, and that its functionality can be proven as beneficial to customers. TasCOSS/TSBC also recommend that Aurora Energy should be able to demonstrate how it can use Aurora+ to reduce its costs and enhance its revenue to offset aurora+ costs in the CTS.

If Aurora+ is included in the CTS, TasCOSS/TSBC consider that setting the allowance for aurora+ should be proportionate to the annual rollout of advanced meters, and/or the uptake of the app. TasCOSS/TSBC consider that this would provide an incentive for Aurora Energy to ensure it meets its meter rollout targets, as well as encourage Aurora Energy to support customers to connect to and use the app.

Mr Dirk Petrusma

Mr Petrusma considers that the Aurora+ app fee is unjust. While he considers that the amount is not great, Mr Petrusma considers that the principle of using an app and being able to pay his account ahead of or on time must be an advantage to Aurora Energy.

7.4 CTS allowances in other jurisdictions

As discussed above, the Regulator's approach was to estimate Aurora Energy's cost to serve allowance using a cost build-up approach and test the result against the CTS allowances in other Australian jurisdictions.

The CTS allowances set by other regulators are discussed below.

ICRC

The 2014 allowance for retail operating costs was based on a benchmark review by IPART in 2012-13.[6] At the time, IPART determined an efficient retail operating cost for a standard retailer (on a per customer basis). This involved undertaking a bottom up analysis, using information provided by retailers operating in NSW on their historic, current and forecast

[6] IPART 2013, *Review of regulated retail prices and charges for electricity – Final Report*.

retail operating costs, and adjusting the results to remove costs recovered elsewhere, such as costs associated with late bill payment as these are recovered through a late payment fee.

In its 2020 Determination, the ICRC calculated that the CTS per customer was $127.84 in 2020-21. The ICRC did not separately estimate a CARC. Instead, when estimating retail operating costs as a whole, the ICRC used a benchmarking approach that considered both cost to serve and reasonable customer acquisition and retention costs.

The ICRC has indexed retail costs to CPI movements since 2014.

ESC

In estimating its most recent retail costs on a per customer basis, the ESC relied on the decision made by the ICRC in its 2017 price determination. These costs have been adjusted for inflation and include an allowance to reflect additional costs associated with operating in Victoria. As described above, the ICRC's 2017 (and 2020) benchmark was originally derived from IPART's 2012-13 benchmarking review.

For 2022, the ESC determined that the VDO's CTS per customer was $181 per residential customer.

QCA

The QCA undertook a comprehensive review of retail costs as part of its 2016-17 price determination. The assessment used a combination of bottom-up and benchmarking methods, using information from public sources (including retail market offers) and confidential information from retailers. Separate retail costs are applied to the fixed and variable cost components of retail prices.

However, the QCA does not set separate retail operating costs (ie CTS) and retail margin. The Regulator is therefore unable to make use of the QCA's recent decisions when setting Aurora Energy's CTS.

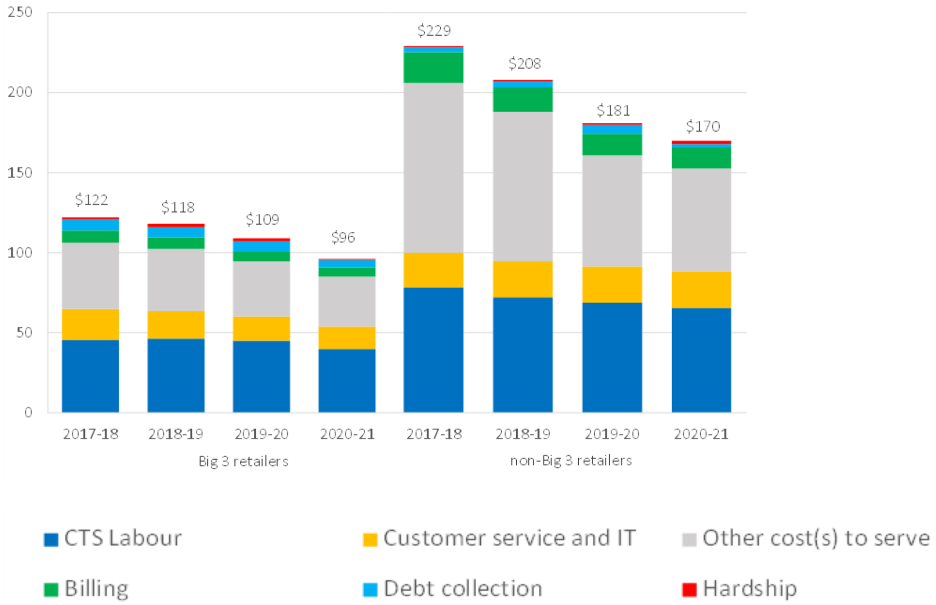
Estimates of Australian retailers' CTS

URA/OGW considered the most appropriate means of testing whether Aurora Energy's base year estimates reflect efficient costs is to compare its proposed costs to publicly available estimates of retailers' cost to serve.

The most recent information is contained in the Australian Competition and Consumer Commission's (ACCC) Inquiry into the National Electricity Market - November 2021 Report. This report breaks down the costs of providing electricity retail services within the NEM and compares the costs in different jurisdictions within the NEM, except Tasmania.

The reported expenditure outcomes in the ACCC's report are categorised between the big 3 retailers and non-big 3 retailers (see Figure 7.1).

Figure 7.1 Average retail and other costs per customer, 2017-18 to 2020-21 ($2020-21, excluding GST)



Source: Based on information from the ACCC's Inquiry into the National Electricity Market - November 2021 report, pages 34 and 37.

Two important findings emerge from these estimates. Firstly, the cost to serve has been falling very significantly in recent years in real terms for large and small retailers. By contrast, Aurora Energy's cost to serve allowance has not fallen in real terms since 2016-17. The ACCC report stated:

> There have been multiple years of consecutive decreases in retail costs per customer in each region, except for Tasmania.[7]

This is the basis for the efficiency factors the Regulator included in the Draft Report.

Secondly, economies of scale are evident in electricity retailers' operations. The average cost to serve of the big 3 retailers was estimated to be a little more than one half of the cost to serve of smaller retailers.

This is consistent with the Aurora Energy's submission, which stated:

> Aurora Energy's costs are largely fixed in nature and do no vary materially with variable components such as the number of customers and customer load.[8]

URA/OGW found that Aurora Energy's proposed CTS ($172.54 per customer) aligns closely with the average costs incurred by non-big 3 retailers ($170 per customer for 2020-21). However, as Aurora Energy's customer base is around three times the average of the non-big 3 retailers and given the opportunities for scale economies, the Regulator would expect an

[7] ACCC, Inquiry into the National Electricity Market - November 2021 report, page 30.

[8] Aurora Energy, Submission to the 2022 Pricing Investigation, page 32.

efficient level of Aurora Energy's cost to serve to be significantly below the average of the non-big 3 retailers.

7.5 Discussion

The Regulator has considered the issues raised in submissions as set out below.

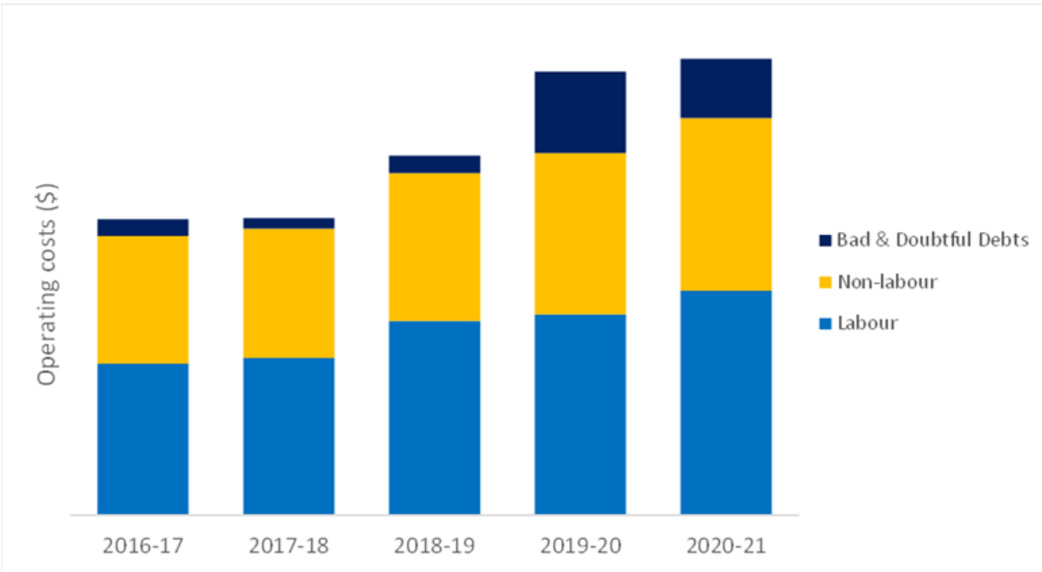
Productivity improvements

The Regulator notes that most of the regulatory decisions cited in Aurora Energy's submission relate to network and water and sewerage businesses rather than retail electricity businesses. It is clear from the ACCC's November 2021 report that there has been a sharp downward trend in the CTS for retailers across the NEM since 2017-18 in nominal and real terms.

In contrast, there has been a large increase in labour costs and also an increase in non-labour costs across Aurora Energy's total business from 2017-18 to 20120-21 (Figure 7.2). While the chart shows cost increases in nominal terms, inflation, including wage inflation, was subdued over this period such that there has been a large cost increase in real terms.

At issue is whether Aurora Energy would have sustained these very significant cost increases if it operated in a highly competitive electricity retail market.

Figure 7.2 Trends in Aurora Energy's retail operating costs ($nominal)



Source: Aurora Energy

The Regulator notes that the efficiency factors in the Draft Report are relatively high, resulting in a reduction in the CTS allowance of around 9 per cent over the period. However, they reflect the trend of declining costs nationally.

Therefore, the Regulator has decided to retain the efficiency factors in the Draft Report of 1.78 per cent in 2022-23 and 3.4 per cent for the next two years.[9]

Bad debt expenses

The Regulator accepts that debt levels in Tasmania are relatively high compared to other jurisdictions. However, the Regulator is not convinced an additional allowance for bad debts is warranted. The Regulator considers that Aurora Energy should be incentivised to find ways to better manage and reduce its bad debt costs. Further, the Regulator notes that the ESC does not currently provide a COVID-19 debt allowance.

Therefore, the decision to remove the additional allowance for bad debts is unchanged from the decision in the Regulator's Draft Report.

aurora+

The Regulator accepts Aurora Energy's proposal to include the aurora+ costs in Aurora Energy's CTS so that, from 1 July 2022, Aurora Energy would no longer separately charge its customers for the app.

However, after considering the issues raised in submissions and re-assessing these costs, the Regulator has decided to reduce the allowance for aurora+ costs further. The rationale for the reduction in the aurora+ allowance is set out below.

Additional call centre costs

In its pricing proposal provided to the Regulator in late October 2021, Aurora Energy based its estimate of additional call centre costs on:

- its forecast of sales of the aurora+ app over 2021-22 and over the next regulatory period, reaching 130 000 customers by 2024-25; and
- an expectation that Aurora Energy customers that have downloaded the app will have a significantly higher call rate to Aurora Energy's call centre, every year, compared to customers that do not have the app.

The Regulator considers that:

- it is reasonable to expect that, after downloading an app such as aurora+, a proportion of customers would contact Aurora Energy's call centre for assistance or to seek additional information, including regarding changes in billing arrangements using the app;
- it would not be expected, however, that such an app should result in permanently higher call rates from these customers. If many customers need to make extra calls to Aurora Energy year after year once they have downloaded the app, this suggests that the app has some shortcomings that need to be addressed. The Regulator notes that the allowance for aurora+ includes the costs of upgrades and enhancements;

[9] The efficiency factor is lower for 2022-23 to reflect efficiency gains that Aurora Energy has recently achieved.

- Aurora Energy states that aurora+ allows customers to apply and secure payment extensions or long term payment plans without contacting Aurora Energy by phone and that this is likely to be attractive to customers to avoid embarrassment. To the extent that call centre activity is reduced, this should represent a cost saving to Aurora Energy; and
- Aurora Energy's forecast uptake of the app appears to be ambitious. Aurora Energy assumes 100 000 customers will be using the app in 2022-23 and 130 000 customers by 2024-25. This represents a large increase from the current level of around 40 000 customers. The Regulator is unaware of any detailed market research undertaken for Aurora Energy to support these forecasts.

Aurora Energy has provided the Regulator with commercial-in-confidence data relating to call centre activity over the past 15 months, which reports on calls from customers with and without the aurora+ app. The Regulator has taken into account this information in its review of aurora+ costs.

In light of these factors and the information provided by Aurora Energy, the Regulator has decided to significantly reduce Aurora Energy's proposed call centre costs relating to aurora+ over the regulatory period. The CTS includes a fixed additional allowance for additional call centre costs before indexation and efficiency factors are applied.

<u>Additional billing costs</u>

Aurora Energy has sought an allowance for additional billing costs associated with aurora+ based on aurora+ allowing customers to pay their bills monthly. The Regulator is not satisfied that significantly more billing issues would arise as a result of monthly bills, compared to quarterly bills, especially as aurora+ provides extensive information to customers on electricity consumption and on the current account balance. It is also likely that more bills will be sent electronically rather than via paper bills as a result of aurora+, which would reduce Aurora Energy's overall bill costs.

Therefore, the Regulator has decided to remove these additional billing costs from Aurora Energy's proposed aurora+ costs.

<u>Marketing costs</u>

In the Draft Report the Regulator reduced marketing costs for aurora+ by one half.

Aurora Energy has invested heavily in aurora+ as a major strategic development for the business. The Regulator's CTS allowance (excluding aurora+) includes costs for customer attraction and retention (CARC). The Regulator expects that some of Aurora Energy's CARC-related activities will be promoting aurora+. Therefore, the Regulator has decided to reduce marketing costs for aurora+, relative to Aurora Energy's initial proposal, by a further by 25 per cent for each year of the upcoming regulatory period.

<u>Impact from reductions in aurora+ costs</u>

Based on the above decisions, the Regulator has decided to allow an average of $9.08 per customer ($2020-21) for aurora+ costs over the 2022-23 to 2024-25 regulatory period which includes the impact of the efficiency factors.

Other issues

The aurora+ app does not currently support Tariff 22. The Regulator has been advised that Aurora Energy is scheduled to provide a version of the app that supports Tariff 22 within the 2022-23 financial year.

Platform and IT costs

Aurora Energy is transitioning from its legacy billing platform (CC&B) to its new billing platform (HubCX). In the Draft Report, the Regulator excluded some operations and maintenance IT billing costs that related to the CC&B platform, which were incurred in the base year of 2020-21. In that year, only a small number of Aurora Energy customers, around 22000, were on the HubCX platform and, as a result, HubCX costs were low in that year.

While all customers are expected to be transferred to the HubCX platform in 2022-23, Aurora Energy had not included the full HubCX operational costs in its submission or its financial model. This was because the operations and maintenance IT billing costs were expected to increase from 2020-21 by around the same level as the CC&B costs that had been included. The Regulator is satisfied that Aurora Energy's annual operational IT billing costs are likely to be around the same level regardless of the billing platform. The Regulator therefore agrees to Aurora Energy's request to include these costs in the cost to serve allowance.

Other costs

In the Draft Report, the Regulator did not include costs that Aurora Energy had proposed for unspecified projects. In Aurora Energy's submission, a set of regulatory and compliance changes were identified that may require additional costs.

The Regulator notes that Aurora Energy currently has an allowance for compliance-related activities within the CTS. The Regulator considers that this allowance is likely to be sufficient to cover any unavoidable project costs relating to regulation and compliance.

The Regulator has therefore decided to not include costs for unspecified projects in the CTS.

Adjusting the CTS due to a change in customer numbers

Consistent with the Draft Report, the Regulator has included an adjustment mechanism in the CTS calculation for Periods 2 and 3 that allows for the recovery of its costs that do not vary with the number of customers, if there is a significant change in customer numbers between periods. The formula provides that, if the change in customer numbers is more than 2 per cent, there is an adjustment to the cost to serve. The formula for the adjustment mechanism is set out in the Final Determination.

Indexation of the CTS allowance

The Regulator considers that indexing Aurora Energy's retail costs to Tasmania's Wage Price Index, for labour costs, and to the Hobart Consumer Price Index, for non-labour costs, is likely to result in changes in the CTS allowance that more accurately reflect underlying cost changes for Aurora Energy. The formula for the indexation of the CTS allowance is set out in the Final Determination.

7.6 Summary

After considering the issues raised in submissions, the Regulator has decided to reduce Aurora Energy's CTS allowance from the level in the Draft Report by:

- decreasing Aurora Energy's proposed call centre costs in relation to aurora+;
- decreasing Aurora Energy's proposed marketing-related costs in relation to aurora+ by a further 25 per cent; and
- removing Aurora Energy's proposed billing costs in relation to aurora+.

As a result of these changes, the allowance for aurora+ costs has been reduced from an average over the 2022-25 regulatory period of $14.15 per customer in the Draft Report to $9.08 per customer in the Final Report.

This is partially offset by the Regulator's decision to increase the allowance for annual operational IT billing costs with the new HubCX platform.

The Regulator's decision is to set a CTS allowance in 2022-23 of $156.31 per customer (2020-21 dollars), including aurora+ costs. This allowance for Aurora Energy's CTS for 2022-23 is around $12.29 per customer lower than in Aurora Energy's most recent submission and around $7.96 per customer higher than the level in 2021-22, in 2020-21 dollars (Table 7.1).

Table 7.1: Comparison of Aurora Energy's approved CTS in 2021-22, Aurora Energy's proposed CTS for 2022-23 and the Regulator's CTS allowance for 2022-23 (2020-21 dollars, per customer)

Aurora Energy's actual CTS allowance for 2021-22	$148.35
Aurora Energy's proposed CTS in its most recent submission	$168.60
Regulator's decision	$156.31

The actual CTS allowance for 2022-23 will be adjusted to take into account the general increases in wages and other costs since 2020-21.

For the second and third year of the regulatory period, the Regulator has decided to adjust the CTS amount for each year by:

- including a mechanism to adjust the CTS to reflect changes in customer numbers;
- using Tasmania's Wage Price Index (ABS CAT NO 6345.0) for Aurora Energy's labour cost components;
- using the Hobart Consumer Price Index (ABS CAT NO 6401.0) for all non-labour cost components; and
- applying an efficiency factor of 3.4 per cent for each year.

8 RETAIL MARGIN

Regulator's Decision

Aurora Energy's retail margin for 2022-23 is $100.90 per customer (in current dollars), which is $95.61 in 2020-21 dollars. The retail margin in 2023-24 and 2024-25 will be the 2022-23 retail margin indexed by growth in the Hobart CPI.

This decision is substantively unchanged from the Regulator's Draft Report except that the value for 2022-23 could not be calculated for that report.

8.1 Background

The retail margin is intended to compensate Aurora Energy for the risks it faces providing standard retail services to its customers. It also enables Aurora Energy to recover financing and depreciation costs that are not included in the CTS. The retail margin is a cost that is included in Aurora Energy's NMR and is therefore ultimately reflected in maximum standing offer prices approved by the Regulator.

Under Section 40AB(1)(b) of the ESI Act, the Regulator is to:

> …take into account the principle that the maximum prices that may be imposed by the retailer under standard retail contracts in respect of small customers are to be such as will enable the retailer, after the operational costs are taken into account, to make a reasonable return on its investment in respect of the provision of standard retail services, taking into account the risk of making that investment.

This chapter discusses Aurora Energy's retail margin for the 2022-25 regulatory period.

The actual retail margin included in the prices to Aurora Energy's customers varies for several reasons. Historically, the retail margin on tariffs to business customers has been higher, on average, than on tariffs to residential customers. Also, the retail margin on time-of-use tariffs such as Tariff 93 and Tariff 94 may be different, on average, from the retail margin on tariffs such as Tariffs 31 and 41, and Tariff 22. In addition, for low consumption customers under all tariffs, Aurora Energy's retail margin is lower than the average retail margin for that tariff, and may be negative. This is because Aurora Energy does not recover all its costs from these customers ie the shortfall is recovered from high consumption customers.

Also, in any year, Aurora Energy's average retail margin, per customer, may be very different from the Regulator's allowed level. This is because Aurora Energy's actual costs for wholesale electricity, renewable energy certificates or its cost to serve may be higher or lower than allowed in the Regulator's Price Determination.

8.2 Draft Report

The Regulator adopted a benchmarking approach to setting Aurora Energy's retail margin in its Draft Report. In determining the retail margin, the Regulator considered the margins set in other jurisdictions and assessed whether Aurora Energy's risks were greater than the risks facing retailers operating in other Australian states and territories.

The Regulator's draft assessment was that Aurora Energy faces lower risks in some areas than other electricity retailers operating in the NEM, especially those that are not part of a vertically integrated business. However, the Regulator acknowledged that it is difficult to quantify the difference in these risks and agreed with Frontier Economics' advice to Aurora Energy that it is not possible to reliably establish the financial risks faced by individual retailers.[10]

The Regulator considered that Aurora Energy's proposed margin of around 5.7 per cent was substantially above the average margin for electricity retailers across Australia in recent years, as reported by the ACCC and would not reflect the recent trend of sharply declining retail margins nationally.[11] .

The Regulator's draft assessment was that a retail margin for Aurora Energy based on 5.25 per cent of approved costs more closely reflects Aurora Energy's risks and recognises the national downward trend in margins the electricity retail industry.

Aurora Energy proposed that the estimate of the dollar value of the retail margin from 2022-23 be based on the dollar value of Aurora Energy's approved retail margin over the past six years, which excluded any margin on aurora + costs.

The Regulator's draft decision was to base the retail margin value at 5.25 per cent of the approved costs for the past two years only, namely 2020-21 and 2021-22 but with an allowance for aurora+ costs even though there was no such allowance in these years.

The justification for using the past two years only was that, in earlier years Aurora Energy's approved costs were higher than in recent years. A dollar value of the retail margin that included these earlier costs would result in a retail margin as a percentage, from 2022-23, that would be higher than 5.25 per cent if overall costs are similar to those in recent years.

The Regulator's draft decision was therefore to set the retail margin at $96.25 per customer in 2022-23 (in 2020-21 dollars), indexed by the Hobart CPI to determine the 2022-23 value in current dollars and then indexed again by CPI growth for 2023-24 and 2024-25. At the time of the Draft Report it was not possible to calculate the 2022-23 value as the relevant CPI data had not been released.

8.3 Submissions received

The stakeholder submissions included the following points relating to Aurora Energy's retail margin. As set out below, all stakeholders other than Aurora Energy consider that Aurora Energy's retail margin should be significantly lower than the level Aurora Energy proposed and the Regulator set out in the Draft Report.

Aurora Energy.

The retail margin should be higher than in the Draft Report for the following reasons:

- Having regard to benchmarking and regulatory precedent, a retail margin based on 5.4 per cent of approved costs is more reflective of the risks and investments of an

[10] Frontier Economics, *Analysis of risk for the purposes of setting the retail margin allowance*. November 2021 (p 14).

[11] ACCC, *Inquiry into the National Electricity Market*. November 2021 report.

efficient retailer in Tasmania. This margin is lower that Aurora Energy's rate of 5.7 per cent in its original pricing proposal.

- The retail margin should be calculated over a historical six year period to ensure the variability in approved costs is adequately covered.

Aurora Energy does not agree with the Regulator's draft assessment that it faces lower wholesale energy and RET-related risks than stand-alone retailers in the National Electricity Market and that they may be higher is some areas~~.~~. The submission states, for example, that Aurora Energy faces a contract price risk of 25 per cent of hedge positions if it sought to contract in line with the methodology for calculating the WEP. Also, due to the absence of liquid and competitive forward contract markets, a retailer with a long contract position may not be able to sell contracts in Tasmania.

The ACCC report that the Draft Report refer to estimates retail margins nationally at low periods in a cycle and the Regulator's retail margin should not be based on these recent trends.

The retail margin allowance should be $105.80 per customer ($2020-21).

COTA Tasmania

COTA Tasmania is disappointed that Tasmanian electricity consumers, and particularly those on low and fixed incomes, are paying a retail margin which is around 100 per cent higher than the average for the NEM. The ACCC report, referred to above, estimated the average retail margin across the NEM at $49 per residential customer in 2020–21, which equates to around a 3.4 per cent margin on their actual costs.

The regulated retail margin needs to be "price competitive" with the retail margin across the NEM and reflect Aurora Energy's market performance and not simply a 'ticket clipping' exercise with Aurora Energy simply passing on its costs to consumers.

Given Aurora Energy's dominant market position in the highly regulated Tasmanian electricity market, the Regulator plays a very important role to ensure that Tasmanian consumers are receiving retail product offers that are highly competitive with those available elsewhere and that Aurora is not over-compensated for the risks it faces.

The retail margin should fall to around $65 to $75 per customer. At this lower level, other retailers will find competing in the small Tasmanian market less attractive, permitting Aurora Energy to maintain the maximum level of operation efficiency.

TREA

As the Regulator is to set prices to allow the retailer to make a reasonable return on its investment, the Final Report should spell out in detail the investment that Aurora Energy has made.

The Regulator should consider Aurora Energy's risks and not systematic or non-diversifiable risks as in Aurora Energy's pricing proposal.

The basis for deciding on a retail margin level should be clearly set out in the Final Report.

TasCOSS/Tasmanian Small Business Council

The current retail margin of 5.7 per cent or $101 per customer compares unfavourably with recent mainland retail margins, as reported in the ACCC report, of 3.4 per cent or $49 per customer.

In considering national trends in the retail margin and factors specific to Aurora Energy, the Regulator appears to have made an upward adjustment but has not explained how.

Aurora Energy faces less wholesale price risk than mainland retailers, including less volume-related risk, given its 97 per cent market share.

A retail margin of around 4.5 per cent, a mid-point between its current margin and the ACCC's estimate of 3.4 per cent, would produce savings of $3.7 million annually and is around $8 million less than under Aurora Energy's pricing proposal.

8.4 What other regulators do

Below is a summary of arrangements in other jurisdictions.

8.4.1 ICRC

The ICRC uses a benchmarking approach when determining the retail margin. In its 2020 determination, the ICRC considered other factors, including the current downward trend in wholesale energy prices which it considered warranted an increase in the retail margin on the basis that this trend represents an increased (wholesale price) risk to retailers. The ICRC assessed that the increase in the retail margin percentage would ensure that the dollar value of the retail margin would remain a reasonable profit margin.

The retail margin for ActewAGL (the regulated retailer in the ACT) is 5.6 per cent of approved costs and was $13.33 per MWh in 2020-21. The ICRC does not publish ActewAGL's load or customer numbers, so a retail margin per customer is not publicly available. However, using Aurora Energy's load and customer numbers, $13.33 per MWh is equivalent to approximately $110 per customer on standing offer prices.

8.4.2 ESC

The ESC also uses a benchmarking approach based on recent decisions by Australian energy regulators to estimate a retail margin for its VDO. The ESC's most recent margin is 5.7 per cent of approved costs which equates to a retail margin of $68 per residential customer for the 2022 calendar year. The margin has decreased in recent years from $79 in 2020 and $73 in 2021. While the retail margin, as a percentage, has been the same as in Tasmania, the dollar value been considerably lower in Victoria, due to the lower level of approved costs.

For its most recent margin, the ESC also examined the level of retail margins in Victoria by analysing retail electricity costs from the cost data submitted by Victorian retailers. The assessment indicated that the average retail margin recovered by retailers in Victoria in 2019-20 and 2020-21 was in line with the margin allowed in the VDO. This suggests that at a broad level there is no significant difference in the retail margins set by the ESC for the Victorian Default Offer and the existing margins in the Victorian retail electricity market.

8.4.3 QCA

The QCA's model does not have a specific allowance for a retail margin. Rather, the margin is included as part of retail costs. The QCA considered it unnecessary to estimate an efficient retail margin. Instead, the QCA's approach focuses on estimating an efficient total level of retail costs, which implicitly includes some retail margin.

8.4.4 Frontier Economics' report on retail costs and margin

In 2019, the ESC engaged Frontier Economics to examine retail costs and margins. Frontier Economics used two approaches to estimate the retail margin - a benchmarking approach and an expected returns approach.[12]

In relation to the benchmarking approach, Frontier Economics reviewed the regulatory allowances used by the QCA (in 2015), the ICRC (in 2014), OTTER (in 2016) and IPART (in 2013). All of these retail margins were 5.7 per cent of approved costs.

Frontier Economics' also used an 'expected returns' approach to estimate a reasonable retail margin. The expected returns approach involves calculating the cost of compensation for the systematic risks associated with an efficient business using the weighted average cost of capital approach. Using this method, Frontier Economics concluded that an acceptable range for the retail margin was between 4.8 per cent and 6.1 per cent.

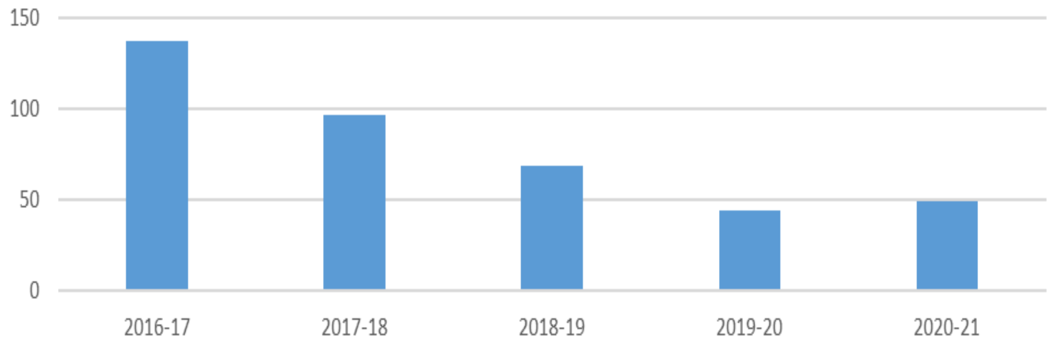
8.4.5 ACCC Inquiry into the National Electricity Market

The ACCC's 2019 Inquiry into the National Electricity Market presented margins achieved by electricity retailers in each jurisdiction for 2018-19. The ACCC used data obtained directly from retailers through its information gathering powers. This information is not otherwise publicly available and only reported on at an aggregate level.

On 13 December 2021, the ACCC released an updated report - Inquiry into the National Electricity Market (November 2021). The average retail margin across the NEM was estimated at $49 per residential customer in 2020–21 (Figure 8.1) which equates to around a 3.4 per cent margin on actual costs.

[12] Frontier Economics, *Retail Costs and Margin: A report for the Essential Services Commission*, April 2019.

Figure 8.1 Estimated retail margin per average residential customer in the NEM ($/customer)



Source: ACCC Inquiry into the National Electricity Market (November 2021), page 31.

According to the ACCC's report, there has been a substantial decline in retail margins from 2016-17, when retail margins peaked at $137 per average residential customer. This represents a decline in the retail margin per customer of around 64 per cent from 2016-17 to 2002-21. The general trend of multi-year decreases in retail margins was observed for all NEM regions except for Tasmania where the ACCC did not separately report on retail costs and margins.

Although retail margins are trending down, the ACCC commented that it is difficult to identify the drivers. However, the ACCC did identify some potentially relevant factors:

- The introduction of the DMO and VDO in 2019 acted to reduce prices for those customers on standing offer prices. The ACCC considered that this could have directly contributed to reduced margins for retailers that previously had material numbers of customers on those higher-priced plans.
- Competition in retailer energy markets and relatively low barriers to entry. In January 2017, there were around 29 retailers that offered electricity contracts. By February 2021, this increased to 44 retailers. While this may not of itself lead to increased competition, the AER identified that retail markets for electricity in south-east Queensland, New South Wales, Victoria and South Australia have several competitive characteristics, such as a diversity of sellers making offers, intensive marketing activity and customer switching.[13]
- The COVID-19 pandemic. The ACCC considered that the effect of the pandemic on retailers' margins is complex and the net impact is unclear. The ACCC noted substantial changes in usage which resulted in increased residential customer usage but decreases in business customer usage, with mixed effects on specific retailers' revenue depending on their market exposure. The ACCC stated that if, as a result of the pandemic, an increasing proportion of customers were unable to pay their electricity bills, this would decrease revenue and so final retail margins would fall.

[13] Australian Energy Regulator, 'State of the Energy Market 2021', July 2021, p 244.

The Regulator has identified some factors that limit the ACCC's findings in informing the allowance to be made for Aurora Energy's retail margin:

- The retail margin estimated by the ACCC was the difference between electricity retailers' reported revenues and costs. This difference for any one year may not be a reliable benchmark for setting regulated retail margins. For example, the ACCC reported that 2020-21 retail margins in South Australia and south-east Queensland were negative.
- Unlike the information provided on the cost to serve, the ACCC report did not publish separate retail margins for the largest three retailers and the other retailers. The reported average retail margin in the NEM was heavily influenced by the retail margin of the largest three retailers, whose combined customer market share in the NEM is around 70 per cent. The average number of customers of the largest three retailers is just under two million or around seven times the number of Aurora Energy's customers.
- Many large retailers in the NEM, including the three largest retailers, are vertically integrated companies that operate generation and retail businesses. These companies generally face lower risks than standalone retailers such as Aurora Energy.
- The ACCC report also stated that the retail margin for a vertically integrated retailer is likely to be largely dependent on the price at which it buys wholesale electricity from its wholesale division which will affect the margin of the retail arm of the business.

Despite these factors, however, the Regulator notes that there has been a very significant decline in the retail margin in mainland Australia in recent years and that this is in contrast to the retail margin in Tasmania, which is relatively high in absolute dollar terms.

8.5 Discussion of risks

In its pricing proposal, Aurora Energy stated that the only risks that should be taken into account should be 'systematic or non-diversifiable risks' only (such as economic, political, or social factors and not risks specific to Aurora Energy). This is consistent with the Capital Asset Pricing Model (CAPM) approach which is used to estimate a weighted average cost of capital.

Aurora Energy engaged Frontier Economics to prepare a report to assist in its response to OTTER's queries on the types of financial risks faced by Aurora Energy, a copy of which was provided to the Regulator on 30 November 2021. The Frontier Economics report concluded that:

- the regulated retail margin should be set to provide compensation for systematic risk only;
- recent regulatory determinations support a regulated retail margin of approximately 5.7 per cent of approved costs; and
- compensation for managing non-systematic risks is provided through other cost allowances.

The Regulator notes that the CAPM methodology is widely used for the pricing of regulated electricity network businesses, as well as businesses in the gas and water and sewerage industries. It can also provide a check on the return to equity implicit in a retail margin.

However, there is no reference to the CAPM methodology in the Regulator's Approach Paper for this investigation, which instead states:

> The Regulator has decided to continue to adopt a benchmarking approach to setting the retail margin that takes into account the risks faced by Aurora Energy and to calculating the margin on a dollar amount per customer basis and including this amount as part of Aurora Energy's cost to serve. The Regulator notes that there is a trade-off between allowing over and under recoveries and the size of the retail margin. To the extent that Aurora Energy's risks are reduced by allowing over and under recoveries to be reflected in prices in the following years, a lower retail margin may be appropriate.[14]

This is also consistent with the requirement in Section 40AB(1)(b) of the ESI Act, reproduced in section 8.1 above, which refers to Aurora Energy making a reasonable return on its investment, taking into account the risks it faces in making that investment.

For this reason the Regulator has examined some specific risks that Aurora Energy faces.

8.5.1 Energy price risk

As discussed in earlier chapters, retailers operating in the NEM are required to purchase electricity through the wholesale spot market. To manage the risks associated with variations in wholesale energy prices, retailers and generators enter into financial risk contracts. Retailers in other NEM jurisdictions have much more liquid and transparent forward contract markets than those in Tasmania.

Unlike in mainland Australia, there is extensive regulation of the wholesale electricity price in Tasmania under the Wholesale Contract Regulatory Instrument (WCRI), as discussed in Chapter 3. The Instrument is designed to produce the type of products that are available in other NEM jurisdictions with deeper and more liquid forward contract markets.

Under the Instrument, specified minimum volumes are set for load following swaps, baseload swaps, peak period swaps, and baseload caps for future quarters up to two years ahead. To the extent that any one product is not taken up by market participants, greater quantities of the other products must be offered.

Chapter 3 also sets out how the Regulator calculates the wholesale electricity price (WEP) that is used in setting standing offer prices each year using the prices of future load following swaps offered over the previous eight quarters (104 weeks) as set out in the Regulator's Guideline, titled *Guideline - Standing Offer Price Approval Process in Accordance with the 2016 Standing Offer Price Determination*.

Importantly, Aurora Energy knows, well in advance, how the Regulator will calculate this WEP. This is unlike how wholesale electricity costs are estimated by the AER for default market offers, where draft forecasts of wholesale costs are prepared by a consultant and the costs are subject to a public consultation process.

Aurora Energy can adopt purchasing strategies, using the load following swap offers from Hydro Tasmania under the Instrument, to reduce its wholesale electricity price risk for a specified volume of electricity such as its forecast total load. The provisions in the Instrument that relate to the volumes of products that Hydro Tasmania must offer assist Aurora Energy in managing this wholesale electricity price risk. The Regulator agrees that Aurora Energy

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14 Tasmanian Economic Regulator, *Retail Electricity Standing Offer Price Methodology Review Paper*, 24 September 2021, page 21.

potentially faces a contract price risk of 25 per cent of hedge positions if it sought to contract in line with the methodology for calculating the WEP. However, the Regulator understands that, in practice, if Aurora Energy did seek to adopt purchasing strategies as discussed above, the actual contract price risk may be substantially less than 25 per cent, depending on Hydro Tasmania's overall contract position.

Aurora Energy does face the risk, however, that the Regulator may change the Guideline (such as calculating the WEP over 52 weeks or 156 weeks) such that the purchasing strategy that Aurora Energy may have commenced would no longer result in the average wholesale price it pays being similar to the WEP. While the Regulator may issue a revised *Guideline* that alters the method of calculating the WEP, it would only be in exceptional circumstances that a new Guideline would require a new method of calculating the WEP to commence immediately. It is much more likely that a new Guideline would require a new method to be implemented after allowing Aurora Energy some time to adjust its contracting activities. The Regulator has decided to not change the Guideline as it applies to the 2022 Price Determination.

Aurora Energy can adopt a range of strategies to manage its wholesale electricity price risks, including purchasing unregulated products from Hydro Tasmania or not hedging some spot market purchases, with the objective of purchasing electricity at a lower average price than the WEP.

Overall, the Regulator's assessment is that, compared to standalone retailers in other Australian jurisdictions, Aurora Energy may face lower than average risks relating to the wholesale electricity price, setting aside volume-related risks.

8.5.2 Volume-related wholesale electricity price risks

Aurora Energy faces a set of risks relating to the volume of electricity it sells and the number of its customers.

As with all retailers, Aurora Energy commits to meeting the entire load of its customers at a set price charged to customers, yet it cannot know in advance what this load will be at different times of any day or over every day, week or month of each year of the regulatory period.

As discussed in the previous section, for a specified volume of electricity, Aurora Energy can adopt a purchasing strategy that would result in the average price it pays for its wholesale electricity being very similar to the WEP. However, the actual load of its customers in any quarter or over the year may be quite different from the forecast load, which requires Aurora Energy to enter into contracts and adopt other strategies to manage the price risks associated with this volume uncertainty.

Factors that affect Aurora Energy's load include:

- Changes in customer numbers, which may be due to:
    - customers switching to and from other retailers;
    - population growth;
    - changes in household formation;
    - growth in the number of dwellings; and

- changes in business conditions that affect the number of potential business customers.

- Changes in average volume of electricity sold per customer and the load profile, which may be due to :
  - variations in weather;
  - competition from other fuel sources;
  - increased customer consumption from installed generation systems such as solar PV rather than from electricity sold by Aurora Energy;
  - increased adoption of battery storage systems;
  - the uptake of energy efficiency measures, including more energy efficient space and water heating systems;
  - the uptake of electric vehicles that are charged at the home or from the premises of some business customers; and
  - changed patterns of work such as more persons working from home.

It is arguable that with recent technological advances, retailers face increasing challenges in forecasting their customers' load.

TasCOSS and the Tasmanian Small Business Council consider that Aurora Energy faces less risk from customer switching compared with retailers in other NEM jurisdictions, as it is claimed that Aurora Energy has low rates of switching to date.[15] Utilities Regulation Authority/Oakley Greenwood report, for example, that the churn rates that Aurora Energy is applying over the regulatory period are low (0.45 per cent), relative to other parts of the NEM.[16]

The Regulator notes that Aurora Energy considers that any adjustment of its retail margin based on variations to customer numbers, load and load profile associated with customers switching between retailers, would be inappropriate.

Around 97 per cent of all residential and small business customers in mainland Tasmania are Aurora Energy's customers. This is a much larger share than for all mainland retailers, including retailers with regulated tariffs. The Regulator's assessment is that Aurora Energy is subject to less risk (compared to other retailers) of large scale changes in load due to customer switching. It is not possible, for example, for Aurora Energy to experience a large increase in customer load due solely to customer switching, given its current market share. Aurora Energy may also expect to lose a smaller percentage of its customers than many retailers due to the small number of other retailers in Tasmania and their very small market share.

The Regulator accepts that, in the absence of liquid and competitive forward contract markets, Aurora Energy faces some additional risks, such as potentially not being able to sell contracts in Tasmania if it finds itself in a long contract position.

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[15] TasCOSS and Small Business Council of Tasmania submission to the draft Approach Paper, 14 May 2021, page 11.

[16] UGA/Oakley Greenwood, Aurora Energy Cost to Serve Review, February 2022, page 6.

In all other respects, however, there is no basis for expecting that Aurora Energy faces volume-related risks, as they apply to electricity sales, that are significantly different from those of other retailers across Australia.

8.5.3 Other risks

Many risks that Aurora Energy faces are faced by all retailers including unexpected increases in operating costs, including IT-related costs. An increasing concern is cyber-related incidents, such as ransomware attacks, and ensuring the integrity and protection of customer data.

Aurora Energy faces asymmetric risks relating to its customer numbers as it is at risk of losing a potentially large market share to other retailers, but has relatively little opportunity to increase its market share, as it has such a large share of the market.

In relation to the treatment of some cost components, the Regulator considers that Aurora Energy may face lower risks than many mainland retailers. For example:

- For some cost components that are based on estimated values, if the actual costs are greater, Aurora Energy is able to recover the difference in the following year (equally, if some costs are lower than estimated, prices will be lower than otherwise in the following year). Many retailers in competitive markets would be reluctant to increase their prices to recover unanticipated costs in the previous year, if there is strong price competition and so would wear the revenue loss. Overall, across years, Aurora Energy has greater certainty that costs will be recovered in its revenue than retailers in competitive markets.
- The Regulator has agreed that Aurora Energy's cost to serve allowance will be able to vary as customer numbers fluctuate so as Aurora Energy is able to recover its fixed costs. Many retailers in competitive markets that lose market share would be reluctant to increase their prices to recover their fixed costs as this could lead to further losses in market share.
- Aurora Energy is able to seek the Regulator's approval of adjustments to compensate for the impacts of a material change in its costs or tax changes.
- The Regulator has agreed to include in Aurora Energy's RET costs, the prices in its long term Power Purchase Agreement (PPA) with Cattle Hill Wind farm. In practice, while retailers do enter into PPA's to reduce their exposure to short term RET prices, there may be no guarantee that they can recover these costs if they face strong price competition. Also, the Regulator has agreed to allow for all of Aurora Energy's actual STC costs.

On the other hand, the Regulator acknowledges that Aurora Energy is a relatively small retailer with a standing offer customer base of around 270 000 electricity customers and a small number of gas customers and is unable to operate outside Tasmania. In comparison, larger NEM retailers can spread costs and risks over a larger customer base and over a wider range of activities, including those that have a substantial number of gas customers.

The Regulator also acknowledges that, as a standalone retailer, in some areas Aurora Energy faces more risks than retailers that are part of a vertically integrated enterprise.

8.6 Summary

It is not straightforward to compare the risks Aurora Energy faces with those faced by other electricity retailers operating in the NEM given the particular features of the electricity market in Tasmania, including the regulatory arrangements for wholesale electricity.

In some areas, Aurora Energy may have lower risks. However, the Regulator acknowledges that it is difficult to quantify the difference in these risks and agrees with Frontier Economics' advice to Aurora Energy that it is not possible to reliably establish the financial risks faced by individual retailers.[17]

Aurora Energy's revenue from the retail margin is designed to enable Aurora Energy to recover its finance and depreciation costs that are not included in the cost to serve. The Regulator has been advised that the capital costs associated with Aurora Energy's new billing platform are substantially lower than for its previous billing system. A lower retail margin to reflect these lower costs would ensure that some of these cost savings are reflected in standing offer prices.

It appears that, nationally, the electricity retail industry is evolving into a relatively low cost, low margin industry. Aurora Energy's proposed margin remains substantially above the average retail margin across Australia in recent years, as estimated by the ACCC.[18] Maintaining a retail margin of around 5.7 per cent would not reflect the recent trend of sharply declining retail margins nationally.

The Regulator has reviewed the submissions from Aurora Energy and stakeholders representing consumers. While the Regulator considers that the proposal from TasCOSS/TSBC to set a retail margin based on the mid-point between its current margin and the ACCC's estimate of 3.4 per cent has some merit, the Regulator notes the limitations of the ACCC's estimate. In particular, it is important to note that the Regulator sets the retail margin allowance in advance, while the ACCC reported on actual retail margins actually achieved, which included unsustainably low or even negative retail margins in some cases.

The Regulator also notes that Aurora Energy's actual average retail margin in its electricity sales to customers on standing offer prices will be determined by a range of factors including its success in achieving the productivity savings in the cost to serve allowance.

On balance, the Regulator has decided that a retail margin based on 5.25 per cent of approved costs over the past two years, including aurora+ costs is appropriate. Since the release of the Draft Report, the Regulator has reviewed its methodology for setting the 2020-21 value of the retail margin. This resulted in some minor changes which, together with the lower allowance for aurora+, has resulted in a marginally lower retail margin at $95.61 per customer ($2020-21).

For 2022-23, the Regulator has set the allowance for the retail margin at $100.90 per customer (in current dollars) which is the CPI-indexed value since 2020-21. This represents a decrease of $10.75 per customer from the retail margin set out in Aurora Energy's submission and a decrease of $4.26 per customer compared to the retail margin in 2021-22 (in $2022-23).

17 Frontier Economics, Analysis of risk for the purposes of setting the retail margin allowance, November 2021, page 14.

18 ACCC, Inquiry into the National Electricity Market - November 2021 report.

For 2023-34 and 2024-25, the value of the retail margin allowance will be indexed by movements in the Hobart CPI as set out earlier in this chapter and in more detail in the Price Determination.

These decisions are substantively the same as in the Draft Report, with the retail margin for 2022-23 now expressed in current dollars.

9 AEMO COSTS

Regulator's decision

The Regulator will continue its current approach to estimating AEMO fees, with fees and charges expressed on a per connection point basis or on a $/MWh basis as relevant and in line with how AEMO expresses the various costs in its annual budget.

This decision is unchanged from the Regulator's Draft Report.

The Australian Energy Market Operator (AEMO) is a not-for-profit public company funded wholly by participant fees. AEMO operates the energy markets and systems and also delivers planning advice in the NEM. Retailers including Aurora Energy are liable to pay fees levied by AEMO. These fees constitute a relatively small part of Aurora Energy's NMR although as AEMO's funding requirements continue to increase[19], AEMO fees are expected to make a larger contribution to the NMR. In 2021-22, for example, these costs were approximately 1 per cent of the NMR.

9.1 Background

AEMO's market fees include the following fees:

- NEM fees. These fees are intended to recover AEMO's costs associated with market operations and systems, wholesale metering, settlements and prudential supervision and longer-term energy forecasting and planning services.
- Full Retail Contestability (FRC) fees. These 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.
- Energy Consumers Australia (ECA) fees. The ECA is an independent body which works with the electricity sector.

AEMO is also responsible, under the NER, 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 purchasing these services, from frequency control ancillary service providers, and recovering a proportion of these costs from retailers according to a set of recovery rules.

Ancillary service fees depend on the number of services required at any particular time and, as this can vary significantly from period to period, the fees will also vary from period to period.

[19] https://www.abc.net.au/news/rural/2022-02-01/renewable-energy-levels-send-grid-management-costs-soaring/100792576.

9.2 Draft Report

As set out in the Draft Report, the Regulator currently estimates Aurora Energy's AEMO fees for participating in the NEM and for FRC electricity by using the customer numbers from the NTB, the DLF and the fees as determined by AEMO.

For ancillary service fees, the Regulator determined these fees 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 DLF.

However, from 2020-21, national transmission planner fees are not borne by market customers; instead, they are payable by transmission network service providers and reflected in network costs. These fees will, therefore, no longer be included in the AEMO component of the cost build-up (these fees were not included in the AEMO component for 2020-21 and 2021-22 under the 2016 Determination).

From 1 July 2021, two new fee categories have been introduced by AEMO to recover the costs of the five-minute and global settlement rule changes and upgrades to related legacy IT systems and the costs of the integration of distributed energy resources (DER) into the NEM.

9.3 Submissions received

No submissions were received on this matter.

9.4 Summary

The Regulator has decided, consistent with the Draft Report, to continue its current approach to estimating AEMO fees.

10 UNDER AND OVER RECOVERIES AND ADJUSTMENTS

Regulator's decision

Under and over recoveries included in the K_y or CF_y cost components of Aurora Energy's NMR are to be limited to network costs, metering costs, AEMO charges and some RET costs; and apply only to the extent that the relevant cost component per unit price is not known at the time prices are set for the next price period.

Also, under and over recoveries are to be calculated using the costs as calculated on the customer numbers and load used to determine the initial costs and prices, ie the Notional Tariff Base, and not the actual customer numbers and load in the year of the under or over recovery.

In calculating the over and under recovery of RET costs, the Regulator will allow for changes in the RPP and STP, which are set by the Clean Energy Regulator, during the relevant period.

The prices used to calculate LGC costs in each year will also be used when calculating any preliminary and final adjustments in relation to LGC costs with respect to each year ie the LGC and prices used when calculating prices in 2022-23 must be used when calculating preliminary and final adjustments in 2023-24 and 2024-25 respectively.

In relation to STC costs, the Regulator will allow the over and under recovery of STC costs due to price differences. That is, Aurora will receive the average actual prices it paid for STCs as it applies to all its load.

In the case of over and under recovery of RET costs relating to years under the 2016 Determination (CF_y), the LGC and STC prices used in calculating the approved prices in the relevant year will be used.

No changes will be made to the current approach to calculating adjustments (A_y).

10.1 Background

The prices to apply to the next financial year are currently approved by the Regulator in June of the preceding financial year, using a building block approach to arrive at an NMR. Some cost components for the financial year, such as the wholesale electricity cost, are already known at the time prices are approved.

However, some cost components must be based on an estimate when calculating the NMR, as the final values will not be known at the time standing offer prices are approved. In the absence of confirmed data from relevant sources, Aurora Energy estimates these costs, for the Regulator's approval, based on the most appropriate method, dependent on the cost component being estimated. These estimates may be higher or lower than the actual values once they become available.

The Regulator will allow Aurora Energy to recover additional costs in any year if actual values exceed the forecast costs for the previous year (and the fourth quarter of the year before). This results in Aurora Energy's NMR and prices being higher than they otherwise would have been (other costs held constant). If actual costs for the previous year are less than the forecast costs, the Regulator will reduce Aurora Energy's approved costs, and its NMR and prices for the next year are lower than they otherwise would have been.

The Regulator seeks to keep under and over recoveries to a minimum. This is because a slightly different set of customers benefit through prices being lower than otherwise in the next period, or are penalised through prices being higher than they otherwise might have been. These adjustments can also lead to greater price volatility from year to year, which the Regulator seeks to avoid.

10.2 Draft Report

The NMR formula in the 2016 Determination allowed for three types of adjustments. These adjustments were:

K_y	=	an aggregate of approved under and/or over recoveries for network costs, metering costs, RET costs and AEMO fees.
A_y	=	an adjustment made as a result of a tax event, a material change in circumstances, or a material change in Aurora Energy's costs in relation to the provision to small customers under standard retail contracts.
CF_y	=	an aggregate of under and/or over recoveries from the previous period covered by the 2013 Determination.

Network costs, metering costs, RET costs and AEMO fees may not be available at the time of publication. Therefore, the adjustment K_y allowed Aurora Energy to recover any of these costs over and above the forecast costs used within the 2016 Determination, or, if actual costs were less than forecast costs, to reduce the allowable NMR in subsequent periods.

Similarly, CF_y allowed Aurora Energy to recover any costs above forecast costs from the last period covered by a previous determination or, if actual costs were less than forecast costs, to reduce the allowable NMR in subsequent periods.

The Regulator's draft assessment was that under and/or over recoveries included in the K_y or CF_y costs[20] are limited to network costs, metering costs, AEMO charges and some RET costs; and apply only to the extent that the relevant cost component per unit price is not known at the time prices are set for the next price period.

The Regulator also intended that under and over recoveries be calculated using the costs as calculated on the customer numbers and load used to determine the initial costs and prices, ie the Notional Tariff Base, and not the actual customer numbers and load in that year.

[20] In the 2022 Determination, CFy will apply to the previous period covered by the 2016 Determination.

In calculating the over and under recovery of LGC costs, the Regulator draft decision was to only allow for changes in the RPP and STP, which are set by the CER, during the relevant period.

Further, the Regulator assessed that the prices used to calculate RET costs in each year will also be used when calculating any preliminary and final adjustments in relation to RET costs with respect to each year ie the LGC and STC prices used when calculating prices in 2022-23 must be used when calculating preliminary and final adjustments in 2023-24 and 2024-25 respectively.

Regulation 12 of the Pricing Regulations provides that the Regulator's price determination may allow an adjustment to Aurora Energy's prices as a result of:

- a tax event; or
- a material change in circumstances in relation to the provision to small customers of services under standard retail contracts.

Given this requirement, the Regulator included a component, A_y, in the NMR formula in the 2016 Determination and intends to include it again in the 2022 Determination.

10.3 Submissions received

No submissions were received on this matter.

10.4 Discussion

As discussed in Chapter 5, the Regulator has decided to approve an allowance for STC costs using the actual prices paid by Aurora Energy as it applies to all its load.

Under this approach, Aurora Energy would provide an estimate in May of the previous year and, through over and under recoveries, Aurora would receive the average actual prices paid for STCs as it applies to all its liable load.

10.5 Summary

The Regulator will adopt the approach in the Draft Report, with the exception of the over and under recovery of STC costs. In relation to STC costs, the Regulator will allow over and under recoveries of STC costs due to differences in the approved average STC price for any year and the actual average STC price for all of Aurora Energy's liable load.

11 AURORA ENERGY'S TARIFF STRATEGY

Regulator's decision

The Regulator approved Aurora Energy's Tariff Strategy.

This decision is unchanged from the Regulator's Draft Report.

11.1 Background

Aurora Energy's Standing Offer Tariff Strategy (Tariff Strategy) sets out its plans for communicating and managing tariffs over the term of the 2022 Determination. A copy of the Tariff Strategy is available on the Regulator's website.

The Tariff Strategy outlines how Aurora Energy intends to manage tariff changes and any rebalancing of fixed and variable components of standing offer prices. It also sets out how it intends to meet shareholder directives and expectations.

During the regulatory period covered by the 2016 Determination, Aurora Energy's Tariff Schedule underwent some significant changes. Changes included the introduction of time-of-use tariffs for residential and business customers (Tariffs 93 and 94 respectively) as well as the removal of several tariffs.

Aurora Energy also incrementally adjusted the fixed and variable relativities of tariffs to reflect the underlying costs and rebalanced tariffs between the residential and business customer segments during the final period of the 2016 Determination (1 July 2021 to 30 June 2022).

As set out in the Approach Paper, Aurora Energy was required to prepare a Tariff Strategy relating to the regulatory period to be covered by the 2022 Determination. The Tariff Strategy was to detail and justify any proposed changes to tariffs and charges for the relevant period, including consultation with its customers. If a tariff is proposed to be made obsolete or abolished, Aurora Energy was required to provide justification and specify the impact on customers.

11.2 2022 Standing Offer Tariff Strategy

Aurora Energy submitted its Tariff Strategy to the Regulator in November 2021. It outlines the factors that underpin Aurora Energy's proposal including customer expectations, regulatory frameworks and future market developments.

Aurora Energy's Tariff Strategy identifies three key principles that will guide its future proposals within the regulatory period to be covered by the 2022 Determination:

- flexibility and simplicity - the ability to amend tariffs to ensure they are relevant, compliant and reflect terms and conditions of underlying network tariffs;

- commitment to cost reflectivity - opportunities to rebalance tariffs, but with regard for customer outcomes; and
- new tariff proposals - the ability to propose new tariffs to reflect evolving customer needs and market signals.

At this stage, there are no firm proposals for new tariffs from Aurora Energy for the 2022-25 regulatory period.

Aurora Energy has identified that changing customer expectations and an increasing trend towards digitalisation of retail service have shaped its approach to the products and tariffs it offers. Aurora Energy considers that the introduction of digital products, such as aurora+, will allow customers to benefit by changing their energy consumption behaviour.

The Tariff Strategy also recognises that the AER's Retail Pricing Information Guideline will shape the presentation of tariffs and how they are communicated with customers.

11.2.1 Regulatory environment

The Tariff Strategy identifies a number of developments that have the potential to impact Aurora Energy's tariffs over the 2022-25 regulatory period. In particular, Aurora Energy considers that the commencement of a new regulatory period for TasNetworks from 1 July 2024 may drive a transition away from flat rate network tariffs towards cost-reflective tariffs. Aurora Energy notes that detail on the future management of network tariffs will not be known until TasNetworks revenue reset is finalised in 2024, and that any material adjustment to underlying network tariffs will be a key input into Aurora Energy's Tariff Schedule during period 3 of the 2022 Determination (2024-25).

Broader electricity market reforms currently being considered by regulatory bodies such as the Australian Energy Market Commission and Energy Security Board may also present opportunities for new tariff products for renewable energy such as distributed generation and electric vehicles. Aurora Energy notes that the format and outcome of these reforms are relatively undefined and therefore any impact on its Tariff Schedule are currently unknown.

11.2.2 Tariff Strategy implementation

Aurora Energy's implementation of its Tariff Strategy will be guided by the three key principles set out above. Aurora Energy is seeking to retain flexibility in relation to whether tariff rebalancing is introduced for any period covered by the 2022 Determination.

11.3 Submissions received

One submission was received in relation to Aurora Energy's tariff strategy.

TREA

Over the next three years, TREA considers that there will be a significant increase in customer owned distributed energy resources, such as the installation of solar PV; installation of home and commercial battery systems; and installation of EV charging systems.

To maximise the benefits from these investments, new tariff strategies will be necessary to send the right price signals to consumers. Therefore, TREA is disappointed that Aurora Energy has proposed no new tariffs for the regulatory period and, to date, there has been no substantive discussion with customer representatives about new tariff types.

TREA considers that the Final Report should provide commentary on whether Aurora Energy's proposed tariff strategy offers sufficient innovation in tariff types to meet the long term interests of customers. Further, the Final Report should also address the issue of whether Aurora should be using opt-in tariffs under market contracts (rather than standing offer tariffs) to trial innovative tariff types.

11.4 Discussion

The Regulator acknowledges the high level of uncertainty around future developments in this space. The Regulator considers that there is sufficient flexibility in Aurora Energy's Tariff Strategy to offer new tariffs. The Regulator also notes that there is nothing preventing retailers other than Aurora Energy from offering new tariffs in Tasmania.

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 would not approve a Tariff Strategy if consumers of electricity were not offered appropriate tariffs by Aurora Energy. The Regulator is satisfied that Aurora Energy does offer an appropriate range of tariffs to electricity consumers in mainland Tasmania

In the event that Aurora Energy's tariffs/tariff structure changes during the regulatory period, the Regulator will assess the impact of any price increases on customers.

11.5 Regulator's decision

The Regulator has approved Aurora Energy's Tariff Strategy.

12 STANDING OFFER PRICE APPROVALS

Under sections 40 and 41 of the ESI Act, Aurora Energy must fix its standing offer prices with the approval of the Regulator and is not permitted to amend those prices unless the Regulator has approved those prices.

Specifically, under section 41 of the ESI Act:

> (1) A standing offer price may not be fixed under section 40(1), and an amendment of a standing offer price may not be made under section 40(4), unless-
>
> (a) a draft of the standing offer price, or a draft amendment of the standing offer price, has been approved by the Regulator under subsection (3); and
>
> (b) the standing offer price fixed, or the draft amendment made, is in the same terms as the draft of the standing offer price, or the draft amendment of the standing offer price, approved by the Regulator under subsection (3).

The Regulator's *Standing Offer Price Approval Guideline* sets out the information Aurora Energy must provide in its annual standing offer pricing proposals under the 2022 Determination. It also details the obligations of Aurora Energy and the Regulator in regards to the approval of prices for each period, consistent with the provisions outlined in the ESI Act.

A Final Standing Offer Price Approval Guideline for the 2022 Determination has been approved by the Regulator and is available on the Regulator's website.

13 OTHER ISSUES

Regulator's decision

The Regulator has decided to review its confidentiality provisions prior to conducting the next pricing investigation in 2024-25.

The Regulator has also decided to examine the merits of introducing separate regulatory accounts and activity-based costings conducting the next pricing investigation in 2024-25.

Both of these decisions are new.

Confidentiality provisions

Under the ESI Act, the Regulator must preserve the confidentiality of information that:

(a) could affect the competitive position of an electricity entity or other person; or

(b) is commercially sensitive for some other reason.

However, the Regulator also recognises that in the interests of an open, public, transparent and fair process, it is desirable that as much information as possible is made public. This is particularly important for pricing investigations as it allows stakeholders to consider information and provide more informed comments and submissions.

To ensure that the confidentiality arrangements are best practice, the Regulator will review its confidentiality provisions prior to conducting the next pricing investigation in 2024-25.

Regulatory accounts and activity-based costing

At present, Aurora Energy is not required to maintain separate regulatory accounts over the course of the regulatory period. As a result, the Regulator did not have access to audited historical data that clearly separated actual CTS expenditure outcomes from Aurora's broader whole of business expenditure.

Similarly, Aurora Energy is not required to maintain activity-based costings over the regulatory period. The absence of expenditure data at an activity level has meant that the Regulator was not able to verify that both direct and indirect non-recurrent CTS costs have been comprehensively accounted for.

The Regulator has decided to examine the merits of introducing separate regulatory accounts and activity-based costings prior to conducting the next pricing investigation in 2024-25.

ATTACHMENT 1: GLOSSARY AND ACRONYMS

Term	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Aurora Energy	Aurora Energy Pty Ltd, ABN 85 082 464 622
Authorised retailer	A person holding a retailer authorisation under the NERL
CARC	Customer acquisition and retention costs (costs incurred by a retailer in acquiring additional customers and retaining existing customers)
CER	Clean Energy Regulator
CPI	Consumer Price Index
DLF	Distribution Loss Factor
Economic Regulator Act	*Economic Regulator Act 2009*
ESI Act	*Electricity Supply Industry Act 1995*
FRC	Full Retail Competition
GWh	Gigawatt-hour (one Gigawatt-hour is 1 000 Megawatt hours or 1 000 000 kilowatt-hours)
Hydro Tasmania	Hydro Electric Corporation, from 1 July 1998, ABN 48 072 377 158
ICRC	Independent Competition and Regulatory Commission, Australian Capital Territory
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
kWh	Kilowatt-hour
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
NEL	National Electricity Law
NERL	National Energy Retail Law, as applied in Tasmania by the *National Energy Retail Law (Tasmania) Act 2012*
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory period	The regulatory period commencing on 1 July 2022
NMR	Notional maximum revenue
NTB	Notional Tariff Base. The notional tariff base 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 (eg 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 2013*
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
Regulator	The Tasmanian Economic Regulator, appointed under the *Economic Regulator Act 2009*
RET	Renewable Energy Target
Retailer authorisation	Authorisation issued by the AER under the National Energy Retail Law. Unless exempt from the requirement, a person must hold a retailer authorisation prior to engaging in the retail sale of energy.
RPP	Renewable Power Percentage
Small customer	A customer who is a small customer under the NERL

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 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	TasNetworks Pty Ltd, ABN 24 167 357 299
Treasury	Tasmanian Department of Treasury and Finance
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 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 developed by Concept Consulting Group Limited for Treasury that is used to calculate the wholesale electricity price.

ATTACHMENT 2: LIST OF SUBMISSIONS

The following parties made submissions in response to the Regulator's Draft Report:

- Tasmanian Labor Party;
- COTA Tasmania;
- Tasmanian Renewable Energy Association;
- Aurora Energy;
- Tasmanian Small Business Council;
- TasCOSS/Tasmanian Small Business Council; and
- Dirk Petrusma.

All submissions are available on the Regulator's website.