ICRC

independent competition and regulatory commission

Final Report

Electricity Model and Methodology Review 2018–19

Report 5 of 2019, May 2019

The Independent Competition and Regulatory Commission is a Territory Authority established under the *Independent Competition and Regulatory Commission Act 1997* (the ICRC Act). The Commission is constituted under the ICRC Act by one or more standing commissioners and any associated commissioners appointed for particular purposes. Commissioners are statutory appointments. Joe Dimasi is the current Senior Commissioner who constitutes the Commission and takes direct responsibility for delivery of the outcomes of the Commission.

The Commission has responsibilities for a broad range of regulatory and utility administrative matters. The Commission has responsibility under the ICRC Act for regulating and advising government about pricing and other matters for monopoly, near-monopoly and ministerially declared regulated industries, and providing advice on competitive neutrality complaints and government-regulated activities. The Commission also has responsibility for arbitrating infrastructure access disputes under the ICRC Act. In discharging its objectives and functions, the Commission provides independent robust analysis and advice.

The Commission's objectives are set out in section 7 and 19L of the ICRC Act and section 3 of the *Utilities Act 2000*.

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Executive Summary

In its final report for the 2017 electricity price investigation, the Commission indicated that it would undertake a review of its pricing model and methodology (Review) for the supply of electricity to small customers on ActewAGL Retail (AAR)'s regulated tariffs.

The purpose of the Review is to ensure that the Commission's pricing model is accurate, reflects current market conditions and retailer practices, and is consistent with the Commission's obligations under the *Independent Competition and Regulatory Commission Act 1997*.

The Commission released an issues paper on 15 October 2018 as the first step in the consultation process for the Review. It sought stakeholder inputs on the current pricing model and on how the Commission proposed to approach the Review. The Commission received one submission from AAR on the issues paper.

The Commission released a technical paper, along with its external expert's review of the methodology for estimating energy purchase costs, on 1 February 2019. The Commission held a technical workshop on energy purchase costs with stakeholders on 13 February 2019. The Commission received three submissions on the technical paper. They were from AAR, the Environment Planning and Sustainable Development Directorate (EPSDD) and the ACT Council of Social Services (ACTCOSS).

The Commission's draft decision was released on 4 April 2019. The Commission conducted a public forum on 15 April 2019, which provided an opportunity for stakeholders to ask questions and provide feedback on its draft decision. The Commission received one submission from AAR on the draft report.

The Commission has considered feedback and information provided in submissions in making its final decision.

The Review found that the Commission's current approach is methodologically sound and simple to implement. Nonetheless, there was scope for improvement which the Commission has decided to implement in the next price investigation to set prices from 1 July 2020. The Commission's final decision largely maintains the current approach with some methodological changes to improve how the Commission estimates energy purchase costs, green scheme costs, energy contracting costs and National Electricity Market (NEM) fees. The Commission will determine appropriate inputs to the methodology and seek stakeholder feedback on these inputs as part of the next price investigation.

Table S.1 summarises the Commission's final decision on the cost components of the current pricing model.

Table S.1 Current methodology and the Commission's final decision

Model component	Current methodology	The Commission's final decision
Energy purchase costs	Estimate energy purchase costs by multiplying observed forward prices (averaged over a 23-month period) by an uplift factor to compensate for hedging costs. Use spot prices and load data since 2003–04 to determine the ACT's load profile. Use base swap contracts to hedge against spot market price volatility.	Maintain the current approach to calculating forward prices averaged over a 23-month period. Use the most recent five years of observed data to determine an appropriate load profile and spot prices. The data will be updated annually as a rolling five-year average. Incorporate a mix of derivatives in the hedging strategy. Determine the contract position each year using a heuristic. The heuristic for the regulatory period will be determined in each price investigation.
National green scheme costs	Increase average certificate prices for a 10 percent holding cost, five per cent mark-up cost and an adjustment for unders/overs.	Maintain the current approach but: • do not include administrative mark-up costs • set holding costs equal to the cost-of-debt averaged over a year.
Energy losses	Apply loss factors to the energy purchase costs, national green costs and NEM fees.	Maintain the current approach that uses loss factor data externally determined by the AEMO.
NEM fees	A 2008benchmark indexed annually for changes in the Consumer Price Index (CPI).	Calculate ancillary fees using a 52-week averaging period and determine NEM fees using observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI.
Energy contracting costs	A 2007 estimate indexed annually for the changes in the CPI.	Review during the next price investigation when the inputs to the model are determined and consider whether these costs are included in retail operating costs.
Retail operating costs	A benchmarking approach indexed to the CPI from 2014.	Maintain the current benchmarking methodology and consider the appropriate benchmarks to use during the next price investigation.
Retail margin	Currently set at 5.3 per cent using a benchmarking approach.	Maintain the current benchmarking methodology and consider the appropriate benchmarks to use during the next price investigation.
Energy Efficiency Improvement Scheme (EEIS) costs	Estimated using a methodology that is set to reflect the ACT Government's legislative requirements subject to a prudency and efficiency assessment.	Maintain the current approach.
Network costs	Pass-through of costs determined by the Australian Energy Regulator (AER).	Maintain the current approach that uses data externally determined by the AER.

1 Introduction

1.1 Background

The Independent Competition and Regulatory Commission (the Commission) is a statutory body set up to regulate prices, access to infrastructure services and other matters in relation to regulated industries. The Commission is the independent regulator of the retail electricity market in the Australian Capital Territory (ACT), responsible for setting regulated retail prices for the supply of electricity to small customers on ActewAGL Retail's (AAR) regulated tariffs.

The Commission undertakes price investigations in accordance with sections 15, 16 and 17 under Part 3 of the *Independent Competition and Regulator Commission Act 1997* (ICRC Act), and issues Price Directions under Part 4 of the ICRC Act. The current Price Direction requires the Commission to determine the maximum prices that AAR can charge for its regulated retail tariffs from 1 July 2017 to 30 June 2020.

The Commission's 2017 investigation used a cost model to determine retail electricity prices for small customers on AAR's regulated tariffs for 2017–20. The investigation noted that this model and the method should be consistent with evolving regulatory best practice in setting regulated prices from 1 July 2020.[1] A model and methodology review (the Review) was established as a reset principle in the Commission's 2017 Price Direction for standing offer prices for the supply of electricity to small customers.

The Commission's approach for this review was to consider separately the components of the model currently used to set retail electricity prices for small customers of AAR.[2] The Commission considered whether the method for calculating each cost component was sound and consistent with evolving regulatory practice. Any changes to the model will be implemented in the regulatory period after 30 June 2020.

The Commission released an issues paper on 15 October 2018 as the first step in the consultation process for the Review. The Commission received one submission on the issues paper, which was from AAR.

The Commission released a technical paper on the energy purchase cost component of the model, along with its external expert's review of energy purchase costs, on 1 February 2019. A technical workshop on energy purchase costs was held on 13 February 2019. The Commission also made available a spreadsheet illustrating how the energy purchase costs can be calculated using the approach recommended by Frontier Economics. The Commission received three submissions on the technical

[1] ICRC, 2017, pp 63–65.

[2] Customers consuming less than 100 MWh per year are defined as small customers.

paper. They were from AAR, the Environment Planning and Sustainable Development Directorate (EPSDD) and the ACT Council of Social Services (ACTCOSS).

The Commission's draft decision was released on 4 April 2019. A public forum was held on 15 April 2019 to provide an opportunity for stakeholders to ask questions and provide feedback on the draft decision. The Commission received one submission from AAR on the draft report.

The Commission has considered feedback and information provided in submissions in the relevant chapters of this report. The submissions are summarised at Appendix 1 and are available on the Commission's website.[3]

This final report sets out the model and methodology the Commission intends to use during the next price investigation to set regulated retail prices from 1 July 2020.

1.2 Structure of the final report

The remainder of the final report is structured as follows:

- Chapter 2 provides an overview of the Commission's current pricing model.
- Chapter 3 sets out the Commission's final decision on the methodologies for calculating wholesale electricity costs, which include energy purchase costs, national green scheme costs, energy losses and NEM fees.
- Chapter 4 sets out the Commission's final decision on the methodology for determining retail costs.
- Chapter 5 sets out the Commission's final decision on the methodology for setting network costs.
- Appendix 1 summarises the submissions to the issues paper, technical paper and draft report.
- Appendix 2 summarises the Commission's draft decision released in April 2019.

[3] www.icrc.act.gov.au.

1.3 Review timeline

The timeline the Commission adopted for this review is presented in Table 1.1.

Table 1.1 Timeline for the Review

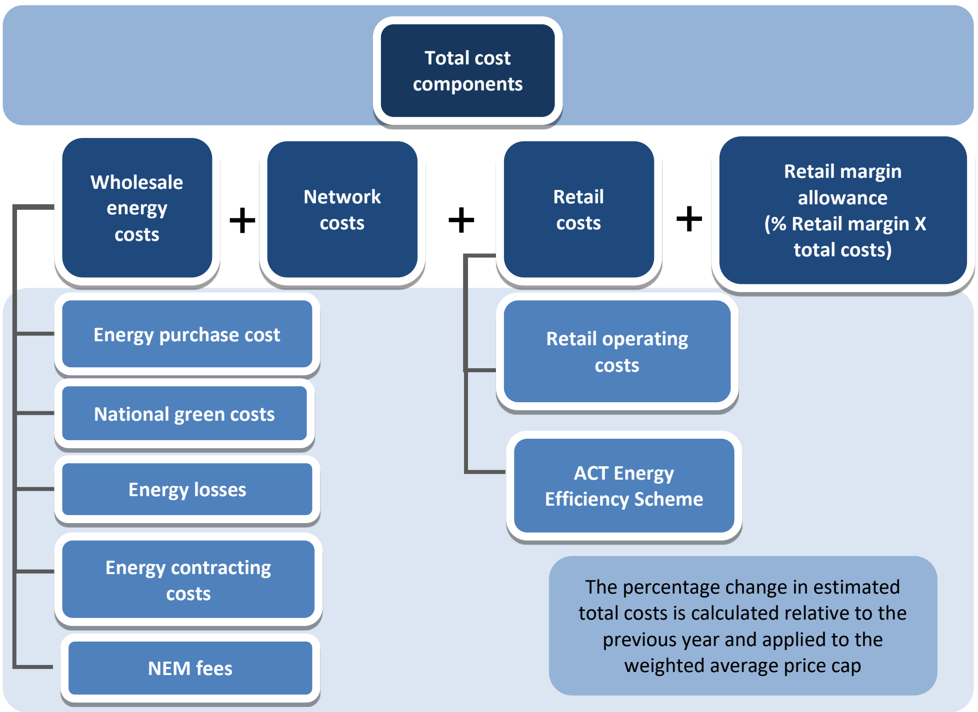
Task	Date
Release of issues paper	15 October 2018
Submissions on issues paper due	16 November 2018
Release of technical paper	1 February 2019
Technical workshop	13 February 2019
Submissions on the technical paper due	26 February 2019
Draft report	4 April 2019
Public hearing	15 April 2019
Submissions on draft report due	2 May 2019
Release of final report	**31 May 2019**

2 Overview of the Commission's current pricing model

The Commission's pricing model is used to determine a dollar per megawatt hour ($/MWh) cost of supplying electricity to retail customers. It does so by estimating key cost components that would be incurred by an efficient retailer in a similar position as AAR when providing electricity supply services to small customers on regulated tariffs.

The current pricing model sets the cost of electricity as the sum of estimated wholesale energy purchase costs, network costs and retail costs, multiplied by a retail margin. The model is illustrated below in Figure 2.1.

Figure 2.1 The Commission's current pricing model



Wholesale costs are the sum of estimated energy purchase costs, Australian Government green scheme costs, energy losses, allowances for contracting costs and the National Electricity Market (NEM) fees.

Energy purchase costs are currently calculated as the average of forward New South Wales (NSW) electricity prices, multiplied by an uplift factor that compensates for the spot price volatility risk in the NEM. The uplift factor comprises the forward price margin, the load shape and the load ratio. The forward price margin is set to five per cent, reflecting the observation that forward prices generally exceed average spot prices. The load shape captures the relationship between the spot price and electricity load. The load ratio takes into account extreme variability in the load.

National green scheme costs are the sum of large and small-scale renewable certificate costs. These certificates are priced as market-traded instruments, with required holdings set by the Clean Energy Regulator (CER). The market prices of the certificates are currently increased by a 10 per cent holding allowance and a five per cent administration cost allowance. Green scheme costs for a given year depend on forecasts of the renewable energy percentages and are adjusted annually for under-and-overs to account for differences between estimated and actual numbers.

Energy losses are calculated by the Australian Energy Market Operator (AEMO). In the Commission's model, these loss factors are applied to the sum of wholesale energy purchase costs, green scheme costs and the NEM fees to account for the electricity lost in transportation from generators to customers.

The NEM fees are the costs of running the market institutions associated with the NEM and ancillary services purchased by NEM institutions; NEM fees are charged by AEMO. The current methodology uses historical estimates of these costs and increases them each year in line with changes in the Consumer Price Index (CPI).

Energy contracting costs are the estimated costs of running an electricity trading desk and are currently indexed for the changes in the CPI.

Network costs include transmission, distribution and jurisdictional scheme costs.[4] The Australian Energy Regulatory (AER) sets the network costs for Evoenergy and the Commission passes through these costs each year.

Retail costs are the sum of retail operating costs and the costs of complying with the ACT Government's Energy Efficiency Improvement Scheme (EEIS). Retail operating costs were set in 2014 to match an Independent Pricing and Regulatory Tribunal (IPART) benchmark and have since been indexed by the CPI.

The retail margin is a percentage applied to the sum of the above estimated costs, providing a return on the investments made by the retailer, and was set for the 2017–20 regulatory period at 5.3 per cent.

Once these cost categories are estimated, they are added together to produce an overall cost to be recovered in $/MWh. This is then compared to the estimated total costs calculated for the previous year to produce a maximum average percentage change that AAR can apply to its regulated tariffs.

More details on these cost components can be found in Chapters 3, 4 and 5 of this report.

[4] Jurisdictional scheme costs include ACT Government's feed-in-tariff costs, energy industry levy and Utilities Network Facilities Tax.

3 Wholesale electricity costs

3.1 Energy purchase costs

Energy purchase costs are the costs incurred by retailers in purchasing electricity from the NEM.[5] Prices in the NEM are volatile and retailers adopt a range of strategies to reduce the business risks of this price volatility. Hedging is one strategy retailers may adopt to reduce their risk exposure. Other strategies that a hypothetical efficient retailer could adopt to reduce its risk exposure include entering long-term contracts with generators or investing in electricity generation.[6]

The energy purchase cost component in the Commission’s model accounts for 36.2 per cent of the estimated total costs for 2018–19.

3.1.1 Current methodology[7]

The Commission’s current energy purchase cost model determines a benchmark cost of purchasing electricity that would be incurred by a hypothetical efficient retailer in a similar position as AAR. This benchmark is based on observed market outcomes and the modelling of a conservative hedging strategy.

The Commission’s energy purchase cost model compensates the hypothetical efficient incumbent retailer for the likely costs associated with spot price spikes in the market. The current model has two key elements: the forward price and the uplift factor.

Forward price

The forward price represents the cost of pre-purchasing electricity to be delivered at a later date. The forward price is calculated using the Australian Stock Exchange (ASX) futures market data for base swap contracts averaged over a 23-month period. The Commission uses average historical data as the best estimate of the forward price facing the retailer. The Commission’s model applies a 23-month forward price averaging period as it may reflect the purchasing window of a prudent retailer. It also smooths out larger fluctuations in forward prices.

Uplift factor

The uplift factor is calculated using load shape, load ratio and the forward price margin, and is applied to the forward price to reflect the retailer’s hedging cost. It

[5] The NEM operates as wholesale spot market interconnecting five regional market jurisdictions – Queensland, NSW (including the ACT), Victoria, South Australia and Tasmania. The NEM involves wholesale generation and is managed by the AEMO.

[6] For relevant economic concepts and salient energy market characteristics, see chapter 2 of Frontier Economics 2019 report on energy purchase costs.

[7] Details of the model can be found in ICRC (2018) and ICRC (2019b).

accounts for the variability in the wholesale electricity cost resulting from both standard and extreme variability and aims to eliminate upside spot market risk. The uplift factor is expressed as $LS \times (1 - M) + LR \times M$.

The forward price margin (M) captures the observation that forward prices generally exceed average spot prices. This is set at five per cent based on data analysis undertaken by the Commission in 2014.

The load shape (LS) reflects the relationship between the spot price and the load. It estimates the extent to which the level of the load[8] and the spot prices move together and is measured by the ratio of the load-weighted spot price to the time-weighted spot price. The weight on the load shape $(1 - M)$ reflects the general effect of load on prices. The LS is calculated using NSW spot prices and the net system load profile for Evoenergy, both reported by the AEMO.

The load ratio (LR), also often described as the load profile, is measured by the ratio of peak load to average load. The LR component can be interpreted as spikes in peak demand. It is calculated as the maximum of the observed ratio of the quarterly maximum load to the quarterly average load using the AEMO data. To complete the calculation of the load ratio, the Commission adds 0.1 to the observed maximum to allow for the possibility of a higher peak.

The Commission's model estimates the energy purchase costs on a quarterly basis. Quarterly energy purchase costs are then converted to an annual average using quarterly load weights.[9] The load weight for each quarter is equal to the historical average load in that quarter divided by the sum of the historical average load for all four quarters from 2003–04.

Cost of carbon

The Commission's model incorporates an adjustment to the wholesale energy purchase cost to account for the cost of carbon. The cost of carbon was introduced to the model following the introduction of the carbon pricing scheme under the *Clean Energy Act 2011*. The scheme was abolished in July 2014. Therefore, the cost of carbon is set at zero in the current energy purchase cost model.

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[8] In the most general sense, the load is the amount of electricity on the grid at any given time, which reflects the demand from consumers.

[9] Demand for electricity varies over the year due to changes in the seasons that change consumer demand. For instance, consumer demand for electricity is high during summer and winter seasons, largely reflecting air-conditioning and heating demands respectively. Quarterly load weights are used to represent these changes in demand and the respective load in calculating the annual average energy purchase costs.

3.1.2 Frontier Economics report on the Commission's energy purchase cost model

In November 2018, the Commission engaged Frontier Economics to advise on the wholesale energy purchase cost component.

In reviewing the Commission's current model, Frontier Economics undertook a comparative assessment of energy market hedging methodologies. It did so by assessing the energy purchase cost methodologies employed by other regulators and alternative energy market hedging strategies. This comparative assessment included an analysis of purchase cost implications, ease of implementation, established regulatory practice, and effectiveness in managing risks.

Frontier Economics' review found that the Commission's current energy purchase cost model is methodologically sound, but there is scope to improve the implementation of the approach. Frontier Economics recommended broadening the hedging strategy from one based on base swap contracts only to one which is based on base swaps, peak swaps, and cap contracts. This broader hedging approach more accurately reflects current retailer practices. Frontier Economics also recommended determining an appropriate contract position (i.e., volume of quarterly base swaps, peak swaps and cap contracts) based on a heuristics approach.

Frontier Economics suggested the Commission determine load and spot prices based on a shorter historical period. The current model, which is based on key inputs averaged back to 2003–04, is less likely to adequately account for important changes in the market over recent years. Frontier Economics further suggested determining a representative year of load and spot prices based on historical data and scaling the half-hourly spot prices to the ASX energy forward prices (adjusted for a contract premium). The scaling aligns the historical spot prices with their future expectations.

Frontier Economics recommended these changes to the Commission's current model to ensure that the model reflects current market conditions and retailer practices.[10]

3.1.3 Submissions

Issues paper submission

In its submission to the issues paper, AAR stated that:

> Any changes to the model should be considered carefully to ensure that the balance between lower retail prices and efficient cost recovery are maintained.[11]

[10] See Frontier Economics, 2019, 'Energy purchase cost review: A report for the ICRC, Sydney: Frontier Economics: Executive Summary. From now onwards, Frontier Economics' report will be cited in this paper as Frontier Economics (2019).

[11] AAR, 2018, p 5.

AAR noted that it would provide its detailed comments once the Commission released its consultant's review of the energy purchase costs.

AAR supported the 23-month averaging period in calculating forward prices.

Submissions on Frontier Economics' report

On 1 February 2019, the Commission released Frontier Economics' final report in a technical paper, together with a summary of the issues and a list of questions on which the Commission was inviting feedback.[12] The Commission conducted a technical workshop on the energy purchase cost model on 13 February 2019.

The Commission received three submissions—from AAR, the EPSDD and the ACTCOSS.

Hedging strategy and contract position

AAR agreed that an efficient retailer would adopt a hedging strategy with a combination of derivatives to manage the spot price volatility risk. If this approach to calculating energy purchase costs was adopted, AAR's view was that the relevant contract positions would need to be linked to the ACT load profile and determined in a way that is relevant to the ACT. AAR noted that the contract positions used in Frontier Economics' report were based on the load profile for Queensland. In AAR's view:

> If the ICRC decides to adopt the Frontier methodology [with a mix of derivatives], the contract position should be determined using a benchmark approach and should be linked to the ACT load profile. Such an approach would be simple, transparent and replicable. [13]

However, AAR supported the current model noting that it works well against the objectives of the ICRC Act.[14]

The EPSDD supported using a hedging strategy with a combination of base swaps, peak swaps and cap contracts that better reflects retailers' risk management practices and actual purchase costs of electricity.[15] The EPSDD supported Frontier Economics' recommendations on determining an appropriate contract position.

[12] See ICRC, 2019a for details.

[13] AAR, 2019a, p 4.

[14] AAR, 2019a, p 3.

[15] EPSDD, 2019, p 2.

Forward price averaging period

In its submission, AAR supported the 23-month averaging period for calculating forward prices.

The EPSDD recommended considering a shorter averaging period for the forward price calculation, such as 12 months.[16] In the EPSDD's view, a shorter averaging period may make it easier for consumers to understand the factors driving changes in annual electricity bills.

The ACTCOSS supported an averaging period that would result in lower electricity prices for consumers:[17]

> Consumers consistently report preferences for price stability, but this is in the context of significant price rises over the past decade…Low- and middle-income consumers, and small and medium enterprises in the private or community sectors would all value early pass through of price reductions rather than smoothing these out over a longer timeframe.[18]

An appropriate load profile for the ACT

With regards to calculating an appropriate load profile for the ACT, AAR suggested adopting either a rolling average approach using more recent data or a weighted average approach applying less weight to historical data.[19]

The EPSDD agreed with Frontier Economics' finding that basing load data on historical outcomes back to 2003–04 is less likely to account for important changes in the market. The EPSDD supported using one or more representative historical years to determine an appropriate load profile for the ACT.[20]

The ACTCOSS stated that:

> The Commission should adopt a shorter averaging period for determining the load profile as current energy policy settings in the ACT are expected to reduce the increase in prices experienced over the past 15 years. [21]

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[16] EPSDD, 2019, p 4.

[17] ACTCOSS, 2019, p 2.

[18] ACTCOSS, 2019, p 2.

[19] AAR, 2019a, p 10.

[20] EPSDD, 2019, p 4.

[21] ACTCOSS, 2019, p 2.

Draft report submissions[22]

In its draft decision, the Commission noted that it would consider incorporating a mix of derivatives in the hedging strategy. In response, AAR's submission noted its concerns about the possible complexities associated with the implementation of Frontier Economics' recommended hedging strategy that uses a mix of derivatives.[23] AAR further noted it would welcome further opportunities to provide feedback if the Commission's final decision is to adopt the mixed derivative approach.

The Commission's draft decision was to use a benchmarking approach to determine the contract position should a broader hedging strategy be adopted. AAR's submission supported this draft decision.[24]

In its draft decision, the Commission proposed to use a Monte Carlo simulation to generate a 'representative' year of loads and spot prices based on the last five years of actual data prior to the price direction. AAR was concerned that the Monte Carlo simulation approach for determining the load and spot prices would add further complexity to the model and reduce transparency of the inputs.[25] AAR suggested that the Commission, instead of employing Monte Carlo generated data, use the full five years of actual historical data to determine appropriate load and spot price data. AAR proposed that the load and spot price data be updated annually as part of the annual price recalibrations.[26]

The Commission's current model applies a 23-month averaging period to calculate forward prices. The Commission's draft decision proposed to continue to calculate forward prices using ASX futures data averaged over a 23-month period. AAR supported this draft decision.

3.1.4 Commission's final decision

Hedging strategy

The Commission considers that the current model is long established, has been widely consulted upon and provides substantial regulatory certainty. The model is also methodologically sound, simple and transparent.

Nevertheless, as mentioned in its draft report, the Commission considers that a hedging strategy that uses base swap contracts only will tend to be both more expensive and riskier than alternative approaches that incorporate a mix of derivatives. Frontier Economics' analysis found that such a hedging strategy may expose the retailer to

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[22] A summary of the Commission's draft decision is available in Appendix 2.

[23] AAR, 2019b, pp 5-8

[24] AAR, 2019b, p 7.

[25] AAR, 2019b, p 7.

[26] AAR, 2019b, p 8.

higher difference payments when load is low and prices are below the strike price, and therefore would be a blunt instrument to manage the NEM price volatilities.[27]

The Commission further notes that a hypothetical efficient retailer would likely adopt a hedging strategy that is closer to Frontier Economics' recommended approach.

A comparison of methodologies used by regulators in other Australian jurisdictions, such as the Queensland Competition Authority (QCA) and the methodology proposed by the Essential Services Commission (ESC) also supports using a mix of derivatives in the hedging strategy.

The Commission's final decision is to adopt Frontier Economics' recommendation to include base swaps, peak swaps and cap contracts in the hedging strategy. The Commission considers that this more accurately reflects retailer hedging strategies and current regulatory practice.

The implementation process of the Commission's final decision will include determining a contract position (the volume of different derivatives), calculating contract prices based on forward prices, developing the half-hourly profile of the load and (scaled) spot prices and calculating settlement payments and difference payments to determine energy purchase costs (details discussed further below).

The Commission will determine appropriate inputs to the methodology and seek stakeholder feedback on these inputs as part of the next price investigation.

Contract position

Determining an appropriate contract position is an important step in implementing the mixed derivatives approach. This 'contract position' determines the amount of quarterly base swaps, peak swaps and cap contracts to use in the model.

The Commission's draft decision was to base the contract position on a heuristic that was linked to electricity demand. As noted in its draft decision, the Commission considers that adopting a benchmarking approach to determine the heuristic would be appropriate as it is simple and transparent.

In response to AAR's submissions to the draft report, the Commission considered available heuristics and did not find one that was based on the ACT's load profile. The Commission's final decision is to develop a suitable heuristic for the ACT using a similar method as adopted by other regulators. This will involve running a model over five years of demand data to get an average efficient contract position. The heuristic will be developed in the next price investigation.

To ensure that the heuristic reflects changes in the electricity market, the Commission will review it at the beginning of each price investigation. The Commission does not

[27] Frontier Economics, 2019, p 24.

expect large changes in the load profile to occur within relatively short periods of time and therefore does not consider annual updates are warranted.

As the heuristic will be linked to the ACT load, the contract positions (the volume of each contract purchased in the hedging strategy) will change annually as the ACT load data is updated (details on the Commission's decision on load data discussed below). In contrast, the heuristics will be reviewed only at the beginning of a regulatory period as part of the price investigation.

Forward price averaging period

The Commission's final decision is to retain its draft decision to continue to apply a 23-month averaging period for the forward price calculation.

The Commission considers that the 23-month averaging period reflects the energy purchasing practices of a prudent retailer in a similar position to AAR. The Australian Competition and Consumer Commission (ACCC) found, in its 2018 report on its Retail Electricity Pricing Investigation (REPI), that most medium to large retailers hedge for two years. The Australian Energy Market Commission (AEMC) has assumed that large retailers hedge for two years in its recent report on residential electricity price trends.[28]

In contrast, the ESC adopted a 12-month forward price averaging period in its recent VDO draft decision. The ESC noted that using a 12-month average does not systematically result in a higher or lower price estimate than using a 24-month average.[29] The ESC also noted that the larger retailers tended to favour a longer averaging period.[30] The Commission notes that there are a large number of electricity retailers operating in the Victoria's retail electricity market. Some are large in terms of size and scope while some are small. The ACCC's 2018 report found that hedging strategies vary depending on the size of the retailers. Some smaller retailers hedge on a short-term basis (for example, from month to month or quarter to quarter) or operate with no hedging in place.[31]

The QCA, for its 2018–19 determination, calculated forward prices using the trade-weighted average of ASX daily settlement data from when the contracts were listed up until 3 April 2018.[32] Base swap contracts are typically listed two to three years in advance. Peak contracts are listed one year ahead.

The 23-month averaging period smooths out large fluctuations in prices. It smooths out both upwards and downwards fluctuations in forward prices and consequently in

[28] AEMC, 2018, p 21.

[29] ESC, 2019, p 24.

[30] ESC, 2019, p 24.

[31] ACCC, 2018, 'Restoring electricity affordability and Australia's competitive advantage: Retail electricity pricing inquiry', pp 108-09.

[32] QCA, 2018, p 13.

wholesale energy purchase costs and retail prices. This means that when wholesale prices increase rapidly, regulated retail prices increase more slowly than wholesale prices. It also means that regulated retail prices will take longer to decline when wholesale prices fall. As mentioned in its draft decision, the Commission notes that the total cost of electricity for consumers, over an extended time period, is not affected by the choice of the averaging period.[33]

Stable prices help consumers to manage their budgets. The Commission considers that the 23-month averaging period is consistent with balancing economic efficiency, environmental and social considerations as required under the ICRC Act. The Commission notes that consumers who prefer to pay electricity prices that are more reflective of current wholesale prices, and are able to manage greater volatility in their electricity bills, can choose a market offer over a standing offer which is based on regulated prices.

In its submission to the Commission's final report, AAR supported maintaining the 23-month averaging period.

Alternative approach to calculating an appropriate load profile

The Commission's model currently estimates the energy purchase costs based on an average historical relationship between spot prices and load since 2003–04. Frontier Economics suggested adopting a shorter period for determining an appropriate load profile for the ACT. The Commission agrees with Frontier Economics that a shorter period will reflect important changes in the market and changes in the pattern of demand over recent years, for example, due to the increasing take-up of air conditioning and rooftop photovoltaic installations (solar panels).

Frontier Economics recommended the Commission analyse historical data to identify one or more years that are representative of future load profiles for the ACT. The Commission analysed trends in the historical load and spot price data and trends in the frequency and timing of high price events to identify representative years. The Commission found the most recent five years to be representative as they had typical load profiles and did not contain an abnormal number of high price events. Frontier Economics recommended that the Commission use load and spot prices from the shorter period to derive a 'representative' year using Monte Carlo simulations.[34]

The Commission compared cross-jurisdictional approaches to estimating a 'representative' year for modelling prices. The ESC in its VDO draft decision used

[33] See ICRC, 2019b, pp 15-17 for details.

[34] In technical terms, the Monte Carlo simulation is a statistical technique that repeatedly draws random samples of load data and spot prices from a data set comprising several years of actual historical data. A Monte Carlo simulation derives a 'representative' year of loads and associated spot prices while retaining the volatility seen in each year of the actual data. In contrast, calculating a simple average across the same years would smooth out the volatility, which would not produce a 'representative' year with typical volatility.

Monte Carlo simulations based on load data and spot price data for the five-year period 1 July 2012 to 30 June 2017. ACIL Allen for the QCA's 2018–19 determination used four years of load data from 2013–14 to 2016–17 along with 46 years of temperature data to develop 47 weather induced simulations.[35] The weather-based simulations were used to reflect the fact that demand for electricity varies with weather conditions.

In its draft decision the Commission proposed to use a Monte Carlo simulation to generate a 'representative' year of loads and spot prices based on the last five years of actual data prior to the price direction. Under this Monte Carlo approach, the settlement and difference payments are calculated for each half-hour trading of the representative year to determine the total cash flow, which is then divided by the total load of that year to determine energy purchase costs.

In its response to the draft decision, AAR suggested the Commission use the full five years of actual historical data to determine appropriate load and spot price data that are updated annually as part of the annual price recalibrations.

The Commission considered costs and benefits, practicalities and complexities associated with both approaches in making its final decision.

The Monte Carlo approach develops data for a representative year using the most recent past five years of actual data. AAR's proposed approach uses the most recent five years of observed data for load and spot prices instead of one year of simulated data generated by the Monte Carlo method. Both methods retain volatility present in spot price and load data.

Nevertheless, the implementation of the Monte Carlo approach would be more complex than AAR's proposed approach. The AAR's approach is replicable and more transparent than the Monte Carlo approach. The Monte Carlo approach has some disadvantages with the most notable being that the resulting outcomes from each random draw would be slightly different. The Commission considers that AAR's proposed approach has the advantages of transparency and ease of implementation compared to the Monte Carlo approach.

The Commission's final decision is to adopt AAR's proposed approach and use the most recent five years of observed data (as available from the AEMO) in determining load and spot prices. Under this approach, the settlement and difference payments will be calculated for each half-hour trading interval of the full five years to determine the total cash flow. The resulting total cash flow will then be divided by the total load for the same five years to determine energy purchase costs. In the determination, the five-year half-hourly spot prices will be scaled to the ASX energy forward prices (less the forward price margin or contract premium, which is set at 5 per cent in the current model) to match the historical spot prices with their future expectations. These scaled data will be used in calculating settlement and different payments. The load and price

[35] ACIL Allen, 2018, p 3.

data will be updated annually as part of subsequent price resets processes to ensure that the model reflects recent changes in the market.

Volatility allowance

A typical hedging strategy adopted by the hypothetical retailer leaves some residual level of exposure to volatile spot prices because buying a contract to cover all possible spot price and demand scenarios can be very expensive. This can be accounted for by holding some working capital (i.e. cash) to fund spot market purchases in the event that electricity demand is larger than accounted for by the hedging strategy. The cost of holding this working capital is known as a volatility allowance.

The recent ESC decision, which adopted a hedging strategy based on a mix of derivatives, included an allowance for volatility to account for the working capital required to cover the costs associated with very high spot prices if those high prices eventuate. Frontier Economics estimated that this working capital requirement is likely to be 3.5 times the standard deviation of wholesale costs.[36] The resulting volatility allowances for the five distribution zones in Victoria for 2019–20 range from $0.12 MWh to $0.18 MWh.[37]

The Commission's final decision is to provide an allowance for volatility. The allowance will be determined during the price investigation using a benchmarking approach. The benchmarking approach will consider the allowance provided by other regulators.

Cost of carbon

The cost of carbon is set at zero in the current energy purchase cost model. The Commission received no submissions on the carbon cost component.

The Commission's final decision is to set the carbon costs at zero.

3.2 National green scheme costs[38]

The Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) are national environmental obligations imposed by the Australian Government to create financial incentives for investment in renewable energy sources. The schemes require electricity retailers to purchase and surrender

[36] ESC, 2019, p 25. The standard deviation is a statistical measure of volatility.

[37] Distribution zones include Ausnet Services, CitiPower, Jemena, Powercor and United Energy.

[38] Technically known as the LRET and SRES costs in the Commission's model.

Large-scale Generation Certificates (LGCs) and Small-scale Technology Certificates (STCs) to the CER in percentages set by regulation each year.[39]

The costs of complying with these schemes are captured in the Commission's National Green Scheme cost component. These costs make up 10 per cent of estimated total costs for 2018–19.

3.2.1 Current approach

The Commission applies a market-based approach for determining efficient LRET and SRES costs. The Commission's method determines average LGCs and STCs prices based on publicly available spot price data. The Commission uses historical spot price data averaged over an 11-month period as the best estimates of the forward prices faced by the retailer. The Commission sources LGC and STC daily spot price data from ICAP.[40]

The Commission adds 10 per cent to the average spot price to compensate the retailer for the costs it incurs in holding the certificates up to their surrender. The Commission also applies a five per cent mark-up to the average spot prices to account for administrative costs. Further, the Commission's approach provides for a cost adjustment each financial year to account for the differences between the estimated and actual renewable energy percentages.

LRET and SRES obligations accrue in calendar year terms while the Commission's pricing model is configured in financial year terms. As such, LRET and SRES costs per financial year are derived by averaging two calendar year estimates. The Commission uses half-yearly load weights provided by AAR to apportion costs across calendar years.

3.2.2 Submissions

Issues paper submission

AAR supported the Commission's current approach for determining efficient costs for LRET and SRES schemes.

In its submission, AAR argued that the Commission should include the holding cost component in the estimation of green costs in order to acknowledge a retailer's legitimate costs of holding certificates purchased from the spot market.[41] AAR also stated that the five per cent administrative mark-up is a reasonable reflection of the

[39] The Renewable Power Percentage and Small-scale Technology Percentage are annual targets to achieve national LRET and SRES targets by 2030, respectively. More information on the LRET and the SRES schemes can be found on the CER's website: http://www.cleanenergyregulator.gov.au/About/Accountability-and-reporting/administrative-reports/tracking-towards-2020-encouraging-renewable-energy-in-australia.

[40] ICAP is a market operator and provider of execution and information services. See www.icap.com.

[41] AAR, 2018, p 6.

costs of managing the LRET and SRES schemes on behalf of the government through retail prices.

Draft report submissions

The Commission's draft decision was to maintain the current approach but to not include holding costs and administrative costs in the calculation, as these costs are already accounted for in the retail operating cost component. In response, AAR noted that:

> It is not necessarily opposed to the [the Commission's draft decision of] inclusion of administrative costs [associated with green costs] in the retail operating costs provided that the methodology is transparent and consistent with the cost recovery requirements of the Act.[42]

However, AAR considered that holding costs should be included with the green costs.[43] It stated that:

> If the ICRC were to use spot prices without adding holding costs, then it would be assuming that the full quantity of certificates are purchased on the last day when they are surrendered but priced at the spot market price averaged over eleven months. Such an approach would be clearly incorrect and inconsistent with the approach used in other jurisdictions.[44]

AAR noted that regulators in other jurisdictions, such as the QCA and (in the past) IPART, incorporated holding costs in their determination of green cost allowance.

3.2.3 Commission's final decision

Complying with the LRET and SRES is mandatory. These green schemes require electricity retailers to purchase and surrender renewable certificates to the CER in percentages set by regulation. The spot price for certificates is determined largely by supply and demand in the wholesale market. While the Commission has no discretion in determining renewable targets or certificate prices, it does have discretion in determining the associated costs such as holding costs and administration costs.

The Commission recognises that retailers face administration costs to participate in the national green scheme. As noted in its draft decision, the Commission considers that these administration costs are accounted for in the retail operating cost allowance of the Commission's model. Retail operating costs account for the efficient costs incurred by the retailer in providing retail services that include administration. AAR supported the Commission's draft decision to include these administrative costs as part of retail operating costs.

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[42] AAR, 2019b, p 10.

[43] AAR, 2019b, p 10.

[44] AAR, 2019b, p 9.

With regards to the holding cost component, the Commission agrees with AAR that the LGCs and STCs are surrendered to the CER on a yearly basis and a quarterly basis, respectively. In meeting their obligations, retailers typically will adopt a practice of buying certificates in advance to manage price volatility and to avoid being unable to buy sufficient certificates to meet their obligations. The Commission recognises that there are legitimate costs associated with holding these certificates prior to their surrender. These costs relate to financing costs.

In the Commission's view, a prudent retailer would, on average, buy these certificates evenly throughout the year. Under this assumption, the average amount of time the certificates are held is equal to half a year. On this basis, the Commission has decided to provide an allowance for holding costs for a half year period. The financing costs associated with holding the certificates are the costs associated with debt. The Commission will determine the cost of debt parameter when it decides inputs to the methodology in the next price investigation.

In summary, the Commission's final decision is to maintain the current methodology but to not add administrative mark-up costs in determining green costs, as these costs are included in the retail operating cost component. The Commission has decided to revise the holding cost in the next price investigation so that it reflects the cost of debt for half a year.

3.3 Energy losses

Some electricity is lost in transporting it from generators to customers via transmission and distribution networks. The energy loss factors are calculated by the AEMO.

Energy losses make up 3.3 per cent of AAR's total estimated costs for 2018–19.

3.3.1 Current approach

The Commission determines the energy losses component by applying the AEMO's transmission and distribution loss factors to the energy purchase cost component, LRET and SRES costs and the NEM fees. The Commission has been applying this approach since 2014.

3.3.2 Submissions

Issues paper submission

In its submission, AAR agreed with the Commission's broad approach to focus the review on cost elements within its regulatory control. AAR agreed that the methodology to determine energy losses was largely out of scope.

Draft report submissions

The Commission's draft decision was to retain the current approach because the loss factors calculated by the AEMO appear to be the most appropriate measure to determine the cost of energy losses. AAR supported this draft decision.[45]

3.3.3 Commission's final decision

Energy losses are a necessary component of the model. In jurisdictions with regulated retail electricity prices, regulators use the AEMO's published loss factors to determine the energy loss allowance.

The Commission's decision is that the current approach for estimating energy losses is appropriate.

The Commission notes that on 5 February 2019 the AEMC received a rule change request from Adani Renewables to revise the existing methodology to calculate loss factors. Should the AEMC decide to change its methodology, the Commission will use the new loss factors when it determines inputs to the methodology in the next price investigation.

3.4 NEM fees

The NEM is managed by the AEMO, which recovers its costs from market participants. Its costs relate to running market institutions and procuring ancillary services to fulfil its obligations under the National Electricity Rules, which are recovered through NEM fees and ancillary services fees, respectively.

The cost components of total NEM fees include general participant fees, Full Retail Competition (FRC) fees, National Transmission Planner fees (NTP), Energy Consumer Australia fees (ECA) and ancillary services fees..

Total NEM fees make up 0.4 per cent of estimated total costs for 2018–19.

3.4.1 Current approach

The Commission's current approach involves applying CPI indexation to a NEM fee adopted from IPART's 2007-10 determination.

3.4.2 Submissions

Issues paper submission

In its submission, AAR supported reviewing the NEM cost component to determine an alternative approach that would use AEMO data. AAR noted that whilst the NEM fees

[45] AAR, 2019b, p 10.

only represent a relatively small proportion of estimated total costs, there is no certainty that these costs will increase in line with the CPI in the future. AAR stated that the current approach based on indexation will likely be inadequate to recover rising future fees. AAR referred to the AEMO's latest report, which forecasts pool fees to increase by 12 per cent, full retail contestability fees to increase by three per cent, national transmission planner fees to increase by seven per cent and ancillary costs to increase significantly over the next regulatory period.[46]

Draft report submissions

The Commission's draft decision was to calculate ancillary fees using a 52-week averaging period and to determine NEM fees using observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI (for both ancillary fees and NEM fees). AAR supported the Commission's draft decision.[47]

3.4.3 Commission's final decision

The Commission recognises that the NEM fees are reasonable costs faced by AAR that should be appropriately passed through in retail electricity prices. However, recognising that NEM fees are not a large component of electricity prices in the ACT, the Commission considers that simplicity and transparency should be considered in determining whether to adopt a more precise methodology.

The Commission considered two key factors in relation to the methodology: deciding on an appropriate averaging period to determine ancillary services fees and determining how often the Commission estimates the NEM fee component within a regulatory period.

To inform its decision, the Commission considered methods used by regulators in other Australian jurisdictions and assessed four possible methods.[48] These included maintaining the Commission's current methodology, adopting the QCA approach, adopting IPART's former approach and adopting the QCA or IPART approach with annual indexation.

The Commission considered that adopting the QCA methodology with annual indexation by the CPI provides the right balance between transparency, use of actual costs and ease of implementation. This method involves calculating ancillary fees using the AEMO's ancillary service payments data averaged over a 52-weeks and determining NEM fees using observed AEMO cost data for the first year of the regulatory period. For subsequent years of the regulatory period, this cost will be indexed to the CPI.

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[46] AEMO, 2018, p 2.

[47] AAR, 2019b, p 10.

[48] Details on these methods can be found in the Commission's draft report, ICRC, 2019, pp 26-28.

The Commission's view is that using the AEMO's published budgeted figures is in line with best regulatory practice, is consistent with the approach taken by regulators in other jurisdictions, and would more accurately reflect forecast increases in the underlying costs faced by the AEMO in operating the NEM.

The Commission's final decision is that it will calculate ancillary fees using a 52-week averaging period and determine NEM fees using observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI.

3.5 Energy contracting costs

Energy contracting costs represent the costs of managing an electricity trading desk.

Energy contracting costs make up 0.4 per cent of estimated total costs for 2018–19.

3.5.1 Current approach

The Commission's current approach involves applying CPI indexation to the previous year's value.

3.5.2 Submissions

Issues paper submission

The Commission did not receive any submissions on the energy contracting costs component.

Draft report submissions

The draft report noted that the Commission would consider energy contracting costs as administrative costs that would need to be considered as part of the Commission's retail operating cost component.[49]

AAR supported the Commission's draft decision and noted that:

> The component for ECC [Energy Contracting Costs] could be moved into the ROC [Retail Operating Cost component] provided sufficient allowance is made for its recovery in the cost index model.[50]

3.5.3 Commission's final decision

As noted in its draft decision, the Commission considers that energy contracting costs are part of administrative costs. The costs associated with administration are accounted for in the Commission's retail operating cost allowance (see section 4.1.1 of Chapter 4

[49] ICRC, 2019b, p 30.

[50] AAR, 2019b, p 10.

of this report). As such, recovering energy contracting costs as a separate allowance may result in double counting.

The Commission's final decision is therefore to review this component of retail operating costs when it determines inputs to the retail operating cost allowance during next price investigation.

4 Retail costs

4.1 Retail operating costs

Retail operating costs are the costs incurred by an efficient retailer in a similar position as AAR in providing retail services to its customers.

Retail operating costs make up 5.7 per cent of estimated total costs for 2018–19.

4.1.1 Current approach

Retail operating costs have been indexed to the CPI since 2014. The 2014 allowance for retail operating costs is based on IPART's 2012–13 benchmark.[51] Prior to this, retail operating costs were determined using a bottom-up approach, benchmarking and indexation to the CPI.[52]

The cost categories included in the Commission's retail operating cost component are:

- customer care and call centre operations;
- billing and charging;
- sales and marketing, being primarily the costs of communicating the transitional regulated tariff arrangements;
- collection and default;
- administration (business overheads such as finance, human resource management and regulatory administration); and
- retail competition activities such as churn management and advertising for new customers.

As described in section 3.5, the Commission considers that energy contracting costs (i.e., the costs of managing an electricity trading desk) are part of administration costs.

The retail operating cost allowance is converted to an allowance per MWh using customer numbers and energy usage. In its most recent decision for 2018–19, the Commission determined an allowance of $14.58 per MWh, equivalent to an average $123.37 per customer.

4.1.2 Submissions

Issues paper submission

In its submission, AAR stated that it supports the Commission's current approach to calculating retail operating costs subject to two adjustments:

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[51] ICRC, 2014b, p 54.

[52] ICRC, 2003, p 13.

- an adjustment to factor in lower economies of scale in operating in the ACT; and
- an adjustment to include customer acquisition and retention costs (CARC) in the retail operating costs allowance. In the AAR's view, a CARC allowance should be added to recover costs incurred from engaging in competition.

Draft report submissions

The Commission's draft decision was to maintain the current benchmarking approach and to consider appropriate benchmarks in the next price investigation. AAR's submission noted that:

> [It] supports continued use of hybrid bottom-up and benchmarked costs. The ICRC's draft decision to move green scheme administrative and holding costs and ECC [energy contracting costs] to the ROC [retail operating costs] requires careful consideration of benchmarks to reflect a hypothetical retailer in the same position as AAR. [53]

The Commission also made a draft decision to not include a separate allowance for CARC or an allowance for lower economies of scale. In response, AAR's submission noted that:

> [AAR reiterated] its request to include allowances for CARC and economies of scale in the ACT.[54]

In support of its request for an allowance for lower economies of scale, AAR noted:

> Given that the retail market in the ACT is one of the smallest in the NEM, unit costs are necessarily higher than in larger jurisdictions. The relatively high unit costs faced by a hypothetical retailer in the same position as AAR are exacerbated by the ICRC's treatment of retail costs as fully variable with respect to customer numbers.[55]

4.1.3 Commission's final decision

The Commission's current approach, using a hybrid of bottom-up and benchmarked costs, is long-established,[56] has been widely consulted upon,[57] and provides regulatory certainty. The Commission has not received information or views during its consultation process for this Review that suggest an alternative methodology is more appropriate.

To assist it in better understanding the nature and relative importance of the various components of retail operating costs, the Commission sought confidential information

[53] AAR, 2019b, p 5.

[54] AAR, 2019b, p 11.

[55] AAR, 2019b, p 12.

[56] ICRC, 2003, pp 12–13.

[57] ICRC, 2017, pp 25–29.

from AAR. AAR provided the Commission with the requested information as well as additional explanation to assist the Commission.

The Commission considers that the current methodology for calculating the retail operating cost allowance is reasonable and reflects current best practice. The Commission's final decision is to maintain the current benchmarking methodology. The inputs to determine the retail operating cost allowance will be informed by the findings from current regulatory investigations and analysis, including the work by, amongst others, the ACCC and ESC (discussed further below).

The remainder of this section discusses the Commission's decision on the two adjustments to the methodology proposed by AAR in its submissions to the issues paper and the draft report. It also discusses current developments that it expects will inform the future implementation of the methodology.

Customer acquisition and retention costs

The Commission has maintained its draft decision that an allowance for CARC in the ACT is not warranted.

While an allowance for CARC is not provided in the current model, other costs relating to retail competition activities (such as churn management and advertising for new customers) are accounted for in the retail operating cost allowance. In the Commission's view, the current retail operating cost allowance recovers reasonable costs relating to retail competition activities that recognise the circumstances in the ACT. Despite AAR's share of customers having dropped over time, AAR remains the dominant retailer in the ACT with a significant market share. In addition, a high proportion of ACT customers are on standing offers compared to the larger jurisdictions.

The Commission's final decision is consistent with the findings of the ACCC's 2018 report that states:

> In NEM regions where there is little competition (that is, in Tasmania, regional Queensland and the ACT, and most consumers are on the standing offer) it is appropriate for the regulated price to include little or no CARC.[58]

Economies of scale

The Commission has maintained its draft decision that an adjustment for lower economics of scale in the ACT is not warranted.

As noted above, AAR continues to dominate the ACT retail electricity market in terms of customer numbers.[59] Consistent with its draft decision, the Commission's assessment is that AAR's position as the dominant retailer in the ACT with a stable

[58] ACCC, 2018, p 249.

[59] https://www.aer.gov.au/retail-markets/performance-reporting/annual-report-on-compliance-and-performance-of-the-retail-energy-market-2017-18.

customer base reduces any potential cost disadvantages associated with lower economies of scale.

The ACCC's 2018 report did not find consistent evidence that economies of scale affect retail operating costs. The ACCC noted that vertically integrated retailers with strong balance sheets and a stable customer base can achieve economies of scale.[60] The ACCC also found that some smaller retailers have much lower costs to serve (i.e., retail operating costs) per customer than some of the large retailers (including some of the big three).[61] Further, the ACCC also found that state retailers with a large customer base, including AAR as well as Ergon Energy and Aurora Energy, have a comparatively low cost to serve (that is, retail operating costs) reflecting their scale.[62] AAR has more than 200,000 customers.[63]

Benchmarks of retail operating costs

As noted above, the inputs to determine the retail operating cost allowance will be informed by the findings from current regulatory investigations and analysis, including the work by, amongst others, the ACCC and ESC.

The Federal Government has directed the ACCC to report on prices, profits and margins in the supply of electricity in the NEM. The terms of reference require the ACCC to provide its first report by 31 March 2019 with subsequent reports released thereafter in every six months until 31 August 2025 [64] The ACCC released its first report on 29 March 2019 setting out the analytical framework for monitoring and providing information about expectations of market outcomes and market participant behaviour.[65] It set out key indicators and monitoring measures that the ACCC intends to report on in its subsequent reports. For retail operating costs, these include an analysis of total and average cost-to-serve retailer costs and CARC retail costs.[66]

The ESC released its draft determination on the VDO in March 2019. The ESC used a benchmarking approach for estimating retail operating costs and considered the ACCC's 2018 findings, market data, data provided by stakeholders and recent regulatory decisions in making the draft decision. The ESC allowed a retail operating cost allowance plus a CARC allowance. The ESC's consultant, Frontier Economics, found that while the retail operating costs allowance based on historical data is between $89 to $129 per customer, the retail operating costs used in regulatory decisions made since 2013 fell within a range of $122 to $129 per customer. The

[60] ACCC, 2018, p 137.

[61] ACCC, 2018, p 224.

[62] ACCC, 2018, p 224. The ACCC's report also noted that the evidence did not demonstrate consistent support for the existence of significant economies of scale as some small retailers have much lower costs to serve than some larger retailers.

[63] ACCC, 2018, p 224.

[64] https://www.accc.gov.au/media-release/accc-to-monitor-and-report-on-electricity-prices.

[65] ACCC, 2019, p i.

[66] ACCC, 2019, p 50.

ESC's draft decision determined an amount of $104.50 per customer for the 2019-20 retail operating costs. In estimating a draft allowance for CARC of $51.48 per customer in addition to the retail operating costs, the ESC used the ACCC's 2018 report findings. The ESC's draft CARC allowance is based on the average CARC for competitive markets across the NEM (of $48 per customer) as reported in the ACCC report adjusted for information.

In its VDO draft decision, the ESC included a separate cost allowance for licence fees. The licence fees are based on the costs incurred by the ESC in performing regulatory functions. The Commission notes that the costs associated with regulatory administration in the ACT are already incorporated in the Commission's retail operating cost allowance in the administration cost category. Therefore, a separate allowance for licence fees is not warranted.

4.2 Retail margin

The retail margin compensates the retailer for managing its services and for the investments it has made in providing electricity to customers such as IT and billing systems.

The retail margin accounts for five per cent of estimated total costs for 2018–19.

4.2.1 Current approach

The Commission set the retail margin in the last two regulatory periods drawing on research undertaken by SFG for IPART in 2013. [67] In 2017, the retail margin was decreased to 5.3 per cent in light of substantial increases in other cost components. The Commission was of the view that:

> A margin at the lower end of that [SFG] range is appropriate given the large increase in wholesale prices and hence the total costs on which the margin is applied.[68]

In making this decision, the Commission noted that the figure of 5.3 per cent is at the lower end of the range estimated by SFG.[69]

4.2.2 Submissions

The Commission stated that it would consider findings and information from recent ACCC and other regulatory investigations, evolving jurisdictional approaches, and other relevant information in determining the margin as part of the next price investigation.

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[67] IPART, 2013, p 94.

[68] ICRC, 2017, p 36.

[69] SFG, 2013, pp 5–15.

Issues paper submission

AAR submitted that its retail margin is amongst the lowest in the NEM. In relation to the Commission's 2017 retail margin decision, AAR stated that IPART applied the SFG's recommended margin on an ex-post basis whereas the Commission currently applies the margin on an ex-ante basis.[70] AAR requested that the Commission converts the ex-post margin of 5.3 per cent to an ex-ante margin of 5.6 per cent as part of this Review.[71]

Draft report submission

The Commission's draft decision was to maintain the current benchmarking approach to determining the retail margin. In its submission, AAR supported the Commission's draft decision but noted that the current retail margin is lower than current regulatory practice in other jurisdictions.[72] AAR reiterated its view that the current retail margin of 5.3 per cent is inconsistent with the retail margin recommended by SFG.[73]

4.2.3 Commission's final decision

The Commission's final decision is to adopt a benchmarking approach to determine the retail margin. The inputs to determine the retail margin will be informed by the findings from current regulatory investigations and analysis, including the work being undertaken by, amongst others, the ACCC and ESC.

The ACCC's first report on retail electricity prices, profits and margins, which was released on 29 March 2019, sets out the analytical framework for monitoring, but its findings on earnings before interest, tax, depreciation and amortization (EBITDA) and earnings before interest and taxes (EBIT) of the retail arms of businesses will not be released until its second report in September 2019.[74] The Commission will consider the information in the ACCC's second report during its next price investigation.

The ESC is currently developing a reference price methodology for the Victorian energy market. In its draft determination for the VDO price, the ESC used a regulatory benchmark approach to estimate the retail margin. The benchmarking results were cross-checked with the estimates from the expected returns approach determined by

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[70] In ex-post calculation, the retail margin percentage is applied to a cost base, which includes the retail margin allowance. In ex-ante calculation, the margin percentage is applied to a cost base without the retail margin allowance.

[71] AAR, 2018, p 10.

[72] AAR, 2019b, p 12.

[73] AAR, 2019b, p 5.

[74] ACCC, 2019, p 50.

Frontier Economics.[75] Using the benchmarking approach, the proposed retail margin ranged from 5.3 per cent to 6.1 per cent on an ex-ante basis. The expected returns approach resulted in a range of 3.5 per cent to 4.3 per cent. The ESC's draft decision was to set the retail margin at 5.7 per cent on an ex-ante basis.

In regard to AAR's submission that the current retail margin is not consistent with the SFG recommended margin, the Commission notes that its 2017 decision was based on the retail margin range identified in the Commission's 2014 decision, which drew on the work undertaken by SFG for IPART.[76] In the 2017 final report the Commission noted that:

> In setting the retail margin for the incumbent retailer at 5.3 percent for the 2017-2020 regulatory period, the Commission notes that this figure is within the range identified in the Commission's 2014 decision based on the work undertaken by SFG for IPART. The Commission is of the view that a margin at the lower end of that [SFG] range is appropriate given the large increase in wholesale prices and hence the total costs on which the margin is applied.[77]

On an ex-ante basis, the SFG's estimated retail margin range varied from a low of 4.1 per cent to a high of 7.5 per cent. As stated in the Commission's 2017 decision on retail electricity costs, the retail margin of 5.3 per cent is within the range estimated by SFG.

The Commission notes that the purpose of this Review is to determine the methodology the Commission intends to use in its next price investigation. Inputs to the methodology, including benchmark for determining the retail margin, will be decided as part of the next price investigation. The Commission will continue to monitor ongoing regulatory investigations, evolving jurisdictional approaches, and other information relevant to informing its next price investigation. Stakeholders will be given further opportunities to provide feedback during the next price investigation.

4.3 EEIS costs

The ACT Government's EEIS places a mandatory obligation on all active retailers in the ACT to promote energy efficiency measures in households and small businesses. The retailer's costs of complying with the scheme are captured in the EEIS cost allowance.

The EEIS compliance costs make up 1.6 per cent of estimated total costs for 2018–19.

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[75] Under the expected returns approach, the retail margin is assumed to provide compensation for an assumed level of systematic risk. It relies on the Capital Asset Pricing Model and an estimated relationship between profitability of retailers and economic conditions (SFG, 2013).

[76] ICRC, 2017, pp 35-36.

[77] ICRC, 2017, p 36; ICRC, 2014a, p 88.

4.3.1 Current approach

The Commission determines the EEIS cost allowance using a methodology that is set to reflect the ACT Government's legislative requirements and cost estimates provided by AAR, subject to a forward-looking prudency and efficiency assessment by the Commission. Since the Commission's methodology relies on forecast and estimated costs in advance of the actual costs being incurred, provision is made for an ex-post adjustment.

4.3.2 Submissions

Issue paper submission

AAR submitted that it agrees with the Commission's broad approach to focus the review on cost elements within its regulatory control. AAR agreed that the methodology to determine EEIS costs was largely out of scope.

Draft report submissions

The Commission's draft decision was to maintain the current approach. AAR supported this draft decision.[78]

4.3.3 The Commission's final decision

The EEIS compliance costs are determined based on the energy saving obligations as set out in the EEIS legislation and reconciled against actual costs incurred by AAR. The Commission's role is limited to reviewing AAR's compliance costs against prudency and efficiency criteria. As the methodology is set to reflect the ACT Government's legislative requirements on AAR, there is little scope for the Commission to alter the current approach.

As such, the Commission's final decision is to maintain the current approach for estimating EEIS costs for the next regulatory period commencing 1 July 2020.

[78] AAR, 2019b, p 5.

5 Network costs

Network costs include transmission, distribution and jurisdictional scheme costs. Jurisdictional scheme costs include the ACT Government's feed-in-tariff costs, energy industry levy and Utilities Network Facilities Tax. These costs are those associated with transporting energy from generators to the ACT's small customers. Network costs are determined by the AER following extensive investigation and consultation.

Network costs make up 37.3 per cent of estimated total costs for 2018–19.

5.1.1 Current approach

The Commission's current approach passes-through the network costs determined by the AER.

5.1.2 Submissions

Issues paper submission

AAR submitted that it agrees with the Commission's broad approach to focus the review on cost elements within its regulatory control. AAR agreed that the methodology to determine network costs was largely out of scope.

Draft report submissions

The Commission's draft decision was to maintain the current approach. AAR supported the draft decision.[79]

5.1.3 Commission's final decision

The AER sets network prices by determining the maximum revenue that a network business is able to recover from customers each year. For the ACT, the relevant network business is Evoenergy. The Commission has no discretion in determining network costs.

The Commission's final decision is to retain the draft decision and maintain the current approach for the next regulatory period from 1 July 2020.

[79] AAR, 2019, p 13.

Appendix 1 Submissions

A.1 Submissions on the issues paper

The Commission received one submission to the issues paper which was from AAR. The key views and information raised in the submission are summarised below. AAR:

- Broadly agrees with the scope of the review that limits the review to the cost elements within the Commission's regulatory control and excludes network costs, EEIS costs and energy losses costs.
- Notes that 'any changes to the energy purchase cost model should be considered carefully to ensure that the balance between lower retail prices and efficient cost recovery are maintained'. Maintains its position that the current uplift factor understates the actual hedging costs faced by a hypothetical efficient mass-market retailer. Assumes that the forward price will continue to be based on the 23-month averaging approach using ASX data.
- Proposes retaining the current approach for calculating national green scheme costs incorporating a 10 per cent holding cost and a five per cent mark-up cost. Argues the Commission should include the holding cost component in the estimation of green costs to acknowledge the legitimate costs of holding certificates purchased from spot markets. Argues that the five per cent administration mark-up is a reasonable reflection of the administrative costs for managing the LRET and SRES schemes on behalf of government through retail prices.
- Supports an alternative approach for calculating NEM fees using observed AEMO data. Noted that the current approach of adjusting the historical value of the NEM fees by the change in the CPI will likely be inadequate to recover rising fees over the next regulatory period.
- Requests that in calculating retail operating costs the Commission make an adjustment to factor to account for lower economies of scale associated with operating in the ACT. Believes a customer acquisition and retention cost allowance should be added to retail operating costs to recover costs incurred from engaging in competition with competitors.
- Argues that the Commission has applied the retail margin on an ex-ante basis which means the ex-post margin needs to be adjusted to ex-ante terms at a minimum.

A.2 Submissions on the technical paper on energy purchase costs

AAR

- Agrees that an efficient retailer would adopt a hedging strategy with a combination of derivatives but notes that the Commission's current model with one derivative works well against the objectives of the ICRC Act.
- Does not consider adopting ACIL Allen's benchmarks to be appropriate because they are specific to Queensland.
- States that if the ICRC decides to adopt Frontier's recommended methodology with a mix of derivatives, the contract position should be determined using a benchmark approach. Such an approach would be simple, transparent and replicable.
- Supports the 23-month averaging period in calculating forward prices.
- Suggests adopting either a rolling average approach using more recent data or a weighted average approach applying less weight to historical data in determining an appropriate load profile for the ACT.

EPSDD

- Supports using a hedging strategy with a combination of base swaps, peak swaps and cap contracts that better reflects retailers' risk management practices and thereby actual purchase costs of electricity.
- Supports Frontier Economics' recommendations in determining an appropriate contract position.
- Recommends considering a shorter averaging period for the forward price calculation such as 12 months.
- Agrees with Frontier Economics' finding that basing load data on historical outcomes back to 2003–04 is less likely to account for important changes in the market.
- Supports using one or more representative historical years to determine an appropriate load profile for the ACT.

ACTCOSS

- Supports an averaging period that would maximise reduced costs to consumers.
- Notes that consumers consistently report preferences for price stability, but this is in the context of significant price rises over the past decade. Low- and middle-income consumers, and small and medium enterprises in the private and community sectors, would all value early pass through of price reductions rather than smoothing these out over a longer timeframe.

- Considers that the Commission should adopt a shorter averaging period for determining the load profile as current energy policy settings in the ACT are expected to reduce the increase in prices experienced over the past 15 years.

A.3 Submissions on the draft report

AAR

- Notes that it remains concerned about the complexities associated with the implementation of the Frontier Economics' recommended hedging strategy that incorporates mixed derivatives.[80]
- Would welcome further opportunities to provide feedback if the Commission's final decision is to adopt the mixed derivative approach.
- Supports using a benchmarking approach to determine an appropriate contract position to use in the energy purchase cost model.
- Is concerned that the Monte Carlo simulation approach for determining the load and spot prices would add further complexity to the model and reduce transparency of the inputs.
- Suggests that the Commission, instead of using Monte Carlo generated data, use the full five years of actual historical data to determine appropriate load and spot price data that are updated annually as part of the annual price recalibrations.
- Not necessarily opposed to the inclusion of administrative costs associated with green costs in the retail operating costs provided that the methodology is transparent and consistent with the cost recovery requirements of the Act.
- Views that the holding costs should be included with the green costs.
- Supports proposed methodologies for energy losses, NEM fees, energy contracting costs, EEIS costs and Network costs provided that sufficient allowances are provided.
- Supports continued use of hybrid bottom-up and benchmarked costs to calculate retail operating costs but requests to include allowances for CARC and economies of scale.
- Supports the Commission's draft decision of using a benchmarking approach to determine the retail margin but notes that the current retail margin is lower than current regulatory practice in other jurisdictions.
- Reiterates that the current retail margin of 5.3 per cent is inconsistent with the retail margin recommended by SFG

[80] AAR, 2019b, pp 5-8

Appendix 2 Summary of the Commission's draft decision

A2.1 The Commission's draft decision (released on 4 April 2019).

Model component	Current methodology	The Commission's draft decision
Energy purchase costs	Estimate energy purchase costs by multiplying observed forward prices (averaged over a 23-month period) by an uplift factor to compensate for hedging costs. Use spot prices and load data since 2003–04 to determine the ACT's load profile. Use base swap contracts to hedge against spot market price volatility.	Maintain the current approach to calculating forward prices averaged over a 23-month period. Use the last five years prior to the price direction to determine an appropriate load profile and spot prices. Consider using a mix of derivatives in the hedging strategy (with an appropriate contract position to be determined in the next price investigation).
National green scheme costs	Average certificate prices increased by a 10 percent holding cost, five per cent mark-up cost and an adjustment for unders/overs.	Maintain the current approach but do not add holding and administrative mark-up costs.
Energy losses	Loss factors applied to the energy purchase costs, national green costs and NEM fees.	Maintain the current approach that uses data externally determined by the AEMO.
National Electricity Market fees	A 2008 benchmark indexed annually for the change in Consumer Price Index (CPI).	Calculate ancillary fees using a 52-week averaging period and determine NEM fees using observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI.
Energy contracting costs	A 2007 estimate indexed annually for the changes in the CPI.	Review during the next price investigation when the inputs to the model are determined and consider whether these costs are included in retail operating costs.
Retail operating costs	A benchmarking approach indexed to the CPI from 2014 benchmark.	Maintain the current benchmarking methodology and consider the appropriate benchmarks to use during the next price investigation.
Retail margin	Currently set at 5.3 per cent using a benchmarking approach.	Maintain the current benchmarking methodology and consider the appropriate benchmarks to use during the next price investigation.
Energy Efficiency Improvement Scheme (EEIS) costs	Estimated using a methodology that is set to reflect the ACT Government's legislative requirements subject to a prudency and efficiency assessment.	Maintain the current approach.
Network costs	Pass-through of costs determined by the Australian Energy Regulator (AER).	Maintain the current approach that uses data externally determined by the AER.

Source: ICRC (2019)

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Abbreviations and acronyms

AAR	ActewAGL Retail
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ACTCOSS	ACT Council of Social Services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CARC	Costumer acquisition and retention costs
Commission	Independent Competition and Regulatory Commission
CER	Clean Energy Regulator
CPI	Consumer Price Index
DMO	Default market offer
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, tax, depreciation and amortization
EEIS	Energy Efficiency Improvement Scheme
ECA	Energy Consumers Australia
EPSDD	Environment, Planning and Sustainable Development Directorate
ESC	Essential Services Commission
FRC	Full Retail Contestability
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
IT	Information Technology

LGC	Large-scale generation certificate
LMRC	Long-run marginal cost
LRET	Large-scale Renewable Energy Target
MWh	Megawatt hour
NEM	National Electricity Market
NMR	Notional Maximum Revenue
NSW	New South Wales
NTP	National Transmission Planner
OTTER	Office of the Tasmanian Economic Regulator
QCA	Queensland Competition Authority
REPI	Retail Electricity Price Inquiry
Review	Electricity Model and Methodology Review
STC	Small-scale Technology Certificate
SRES	Small-scale Renewable Energy Scheme
VDO	Victorian Default Offer
WACC	Weighted average cost of capital

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