ICRC

independent competition and regulatory commission

Draft Report

Electricity Model and Methodology Review 2018–19

Report 3 of 2019, April 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*.

Correspondence or other inquiries may be directed to the Commission at the following addresses:

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The Commission may be contacted at the above addresses, by telephone on (02) 6205 0799, or by fax on (02) 6207 5887. The Commission's website is at www.icrc.act.gov.au and its email address is icrc@act.gov.au.

How to make a submission

This draft report provides an opportunity for stakeholders to give feedback and views on the Commission's draft decisions on the model and methodology it intends to use in making its decision on regulated retail electricity prices during the price investigation for the next regulatory period. It will also ensure that relevant information and views are made public and the Commission can consider relevant information and views in making its final decision on the model and methodology.

Submissions on the draft report close on **2 May 2019.**

Submissions may be mailed to the Commission at:

Independent Competition and Regulatory Commission
PO Box 161
Civic Square ACT 2608

Alternatively, submissions may be emailed to the Commission at icrc@act.gov.au. The Commission encourages stakeholders to make submissions in either Microsoft Word format or PDF (OCR readable text format – that is, they should be direct conversions from the word-processing program, rather than scanned copies in which the text cannot be searched).

For submissions received from individuals, all personal details (for example, home and email addresses, and telephone and fax numbers) will be removed for privacy reasons before the submissions are published on the website.

The Commission is guided by the principles of openness, transparency, consistency and accountability. Public consultation is a crucial element of the Commission's processes. The Commission's preference is that all submissions it receives be treated as public and be published on the Commission's website unless the author of the submission indicates clearly that all or part of the submission is confidential and not to be made available publicly. Where confidential material is claimed, the Commission prefers that this be under a separate cover and clearly marked 'In Confidence'. The Commission will assess the author's claim and discuss appropriate steps to ensure that confidential material is protected while maintaining the principles of openness, transparency, consistency and accountability.

The Commission may be contacted at the above address, by telephone on (02) 6205 0799 or via the Commission's website at www.icrc.act.gov.au.

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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 proposes 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 energy purchase costs, on 1 February 2019. Following this, 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 has considered feedback and information provided in submissions in making its draft decision.

Table S.1 summarises the Commission's draft decision on the cost components of the current pricing model. The Commission welcomes feedback on its draft decision. The Commission will consider this feedback in developing its final report that will set out the methodology and outline the model the Commission proposes to use during the next price investigation in setting regulated retail prices from 1 July 2020.

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

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.	Maintain the current approach to calculating forward prices averaged over a 23-month period.
	Use spot prices and load data since 2003–04 to determine the ACT's load profile.	Use the last five years prior to the price direction to determine an appropriate load profile and spot prices.
	Use base swap contracts to hedge against spot market price volatility.	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	Currently indexed 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	Currently indexed to 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.

The Commission intends to conduct a public forum on 15 April 2019, which will provide an opportunity for stakeholders to ask questions and provide feedback on its draft decision.

The final report is planned to be released in May 2019. It will set out the model and methodology the Commission proposes to use during the next price investigation to set prices from 1 July 2020.

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 is to consider separately the components of the model currently used to set retail electricity prices for small customers of AAR. It is also considering how the different components of the pricing model interact and whether the Commission's overall approach is reasonable. 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.

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

The Commission has considered issues raised in the submission in the relevant chapters of this report. The submissions are summarised at Appendix A and are available on the Commission's website.[2]

1.2 Structure of the draft report

The remainder of the draft report is structured as follows:

- Chapter 2 provides an overview of the Commission's current pricing model.
- Chapter 3 sets out the Commission's proposed methodology 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 proposed methodology for determining retail costs.
- Chapter 5 sets out the Commission's proposed methodology for setting network costs.
- Appendix 1 summarises the submissions to the issues paper and technical paper.
- Appendix 2 sets out the Commission's analysis of NEM fees.

1.3 Review timeline

The closing date for submissions on the draft report is 2 May 2019. Submissions received by the closing date will be considered by the Commission in developing the final report.

The Commission intends to conduct a public hearing on 15 April 2019. The hearing will provide an opportunity for stakeholders to ask questions and provide feedback on the draft report.

The final report will set out the methodology the Commission proposes to use during the next price investigation to set regulated retail prices from 1 July 2020.

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

The indicative timeline for the review is set out in Table 1.1.

Table 1.1 Indicative timeline for the Review

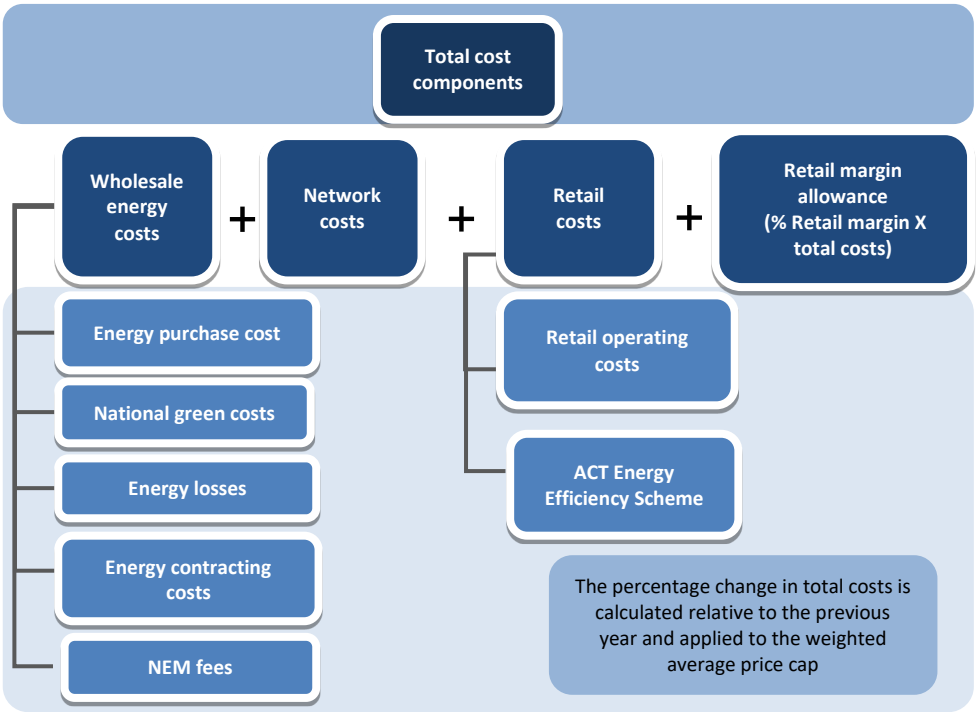
Task	Date
Release of issues paper	15 October 2018
Submissions on issues paper due	16 November 2018
Release of technical paper	1 February 2019
Technical workshop	13 February 2019
Submissions on the technical paper due	26 February 2019
Draft report	**4 April 2019**
Public hearing	15 April 2019
Submissions on draft report due	2 May 2019
Release of final report	End 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.[3] The Australian Energy Regulatory (AER) sets the network costs for Evoenergy and the Commission passes-through these costs for 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 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 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.

[3] 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.[4] 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.[5]

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

3.1.1 Current methodology[6]

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

[4] 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.

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

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

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 a 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[7] 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.[8] 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.

3.1.2 Matters raised in the issues paper

In the issues paper, the Commission sought feedback from stakeholders on the current methodology as well as on the Commission's approach to reviewing it.

[7] 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.

[8] 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.

The Commission's current energy purchase cost model is complex and technical, and the parameters are interrelated. The Commission noted in its issues paper that it would engage an external expert consultant to review the current energy purchase cost methodology as a whole.

3.1.3 Issues paper submission

In its submission to the issues paper, AAR stated that the current uplift factor to calculating hedging costs underestimates the actual hedging costs faced by a hypothetical efficient mass-market retailer. AAR also 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.[9]

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.

3.1.4 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 comparable jurisdictions and alternative energy market hedging strategies. This comparative assessment included an analysis on 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 to reflect current retailer practices. These recommendations included revising the Commission's current hedging strategy to include base swaps, peak swaps, and cap contracts and 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 recommended these changes to the

[9] AAR, 2018, p 5.

Commission's current model to ensure that the model reflects current market conditions and retailer practices.[10]

3.1.5 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. The Commission conducted a technical workshop on the energy purchase cost model on 13 February 2019.

The Commission received three submissions—from AAR, EPSDD and 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 is 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. [11]

However, AAR supported the current model noting that it works well against the objectives of the ICRC Act.[12]

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.[13] The EPSDD supported Frontier Economics' recommendations on determining an appropriate contract position.

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[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, 2019, p 4.

[12] AAR, 2019, p 3.

[13] 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.[14] 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.[15]

> 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.[16]

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.[17]

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.[18]

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. [19]

[14] EPSDD, 2019, p 4.

[15] ACTCOSS, 2019, p 2.

[16] ACTCOSS, 2019, p 2.

[17] AAR, 2019, p 10.

[18] EPSDD, 2019, p 4.

[19] ACTCOSS, 2019, p 2.

3.1.6 Commission's draft decision

Hedging strategy

The Commission's current model is long established, has been widely consulted upon and provides substantial regulatory certainty. The Commission notes Frontier Economics' finding that the Commission's model is methodologically sound, simple and transparent. AAR's submission supported the current model because it has performed well against the objectives of the ICRC Act.

Nevertheless, the Commission considers that there may be benefits in adopting an approach to modelling energy purchase costs that is based on a hedging strategy that includes a mix of base swaps, peak swaps and base cap contracts. The Commission accepts Frontier Economics' view that a hedging strategy that is based on 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 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.[20]

The Commission accepts 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 supports using a mix of derivatives in the hedging strategy. The approach currently adopted by the Queensland Competition Authority (QCA) and the methodology proposed by the Essential Services Commission (ESC) for its draft Victorian Default Offer (VDO) incorporated hedging strategies with a mix of derivatives. As noted above, the EPSDD's submission to the Commission's technical paper also supported introducing a hedging strategy with a mix of derivatives including base swaps, peak swaps and cap contracts.

The Commission considers that incorporating a mix of derivatives is likely to better reflect current retailer practices and risk policies.

However, the benefits from adopting the approach to modelling energy purchase costs recommended by Frontier Economics must be weighed against the benefits of retaining the Commission's existing approach. The Commission's existing approach has the advantages of simplicity, transparency and ease of implementation compared to the slightly more complex approach recommended by Frontier Economics. Both the current methodology and the methodology recommended by Frontier Economics are methodologically sound.

On balance, the Commission is inclined to consider adopting Frontier Economics' recommendation to include a mix of derivatives in the hedging strategy because it

[20] Frontier Economics, 2019, p 24.

more accurately reflects retailer hedging strategies and current regulatory practice. However, some practical questions would need to be resolved if the Commission were to adjust its methodology along the lines recommended by Frontier Economics, including, importantly, which benchmarks to use for setting the contract position (discussed further below).

The Commission intends to give further consideration to these practical implementation questions and seeks stakeholder feedback to assist it in coming to a final decision.

Contract position

Should the Commission adopt Frontier Economics' recommended approach, the Commission would need to determine an appropriate contract position (i.e., the volume of quarterly base swaps, peak swaps and cap contracts) to use in its model. There are two possible ways to determine an efficient combination of derivatives to meet a particular load profile. The first method uses a modelling approach to determine the efficient contract position. The second approach is to use a set of benchmarks. The benchmarking approach is simple, transparent, and does not require forecasts of future prices (in contrast to modelling a contract position).

Frontier Economics recommended the Commission adopt a benchmarking approach based on the set of benchmarks (or heuristic) used by ACIL Allen for the QCA's energy purchase cost determination.

AAR's submission on the technical paper raised concerns over the appropriateness of ACIL Allen's heuristic for the ACT. The Commission agrees with AAR that the heuristic adopted should be appropriate to the demand characteristics of the ACT.

Should Frontier Economics' recommended hedging strategy be adopted, the Commission's draft decision is to adopt a heuristic for the contract position. An important consideration for the Commission is ensuring that the basis for the heuristic is clear and transparent.

If the Commission's final decision is to adopt Frontier Economics' recommendation to include a mix of derivatives in the hedging strategy, the Commission will determine benchmark volumes or percentages for base swaps, peak swaps and cap contracts that would be appropriate for the ACT during the next retail electricity price investigation.

Forward price averaging period

As mentioned earlier, the Commission's current model applies a 23-month averaging period in calculating forward prices as it considers that it reflects the energy purchasing practices of a prudent retailer in a similar position to AAR. This averaging period also smooths out large fluctuations in prices. Stable prices help consumers to manage their budgets. The Commission considers the use of an averaging period is consistent with

balancing economic efficiency, environmental and social considerations as required under the ICRC Act.

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. 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.[21] The Australian Energy Market Commission (AEMC) has assumed that large retailers hedge for two years in its recent report on residential electricity price trends.[22]

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.[23] The ESC also noted that the larger retailers tended to favour a longer averaging period. [24]

The QCA, for its 2018–19 determination, calculated forward prices using the trade-weighted average of ASX daily settlement data since the contracts were listed up until 3 April 2018.[25] Base swap contracts are typically listed two to three years in advance. Peak contracts are listed one year ahead.

In making its draft decision, the Commission has examined the implications of a 12-month averaging period compared to a 23-month averaging period for the prices paid by ACT consumers.

Figure 3.1 shows daily forward prices and prices averaged over 12-month and 23-month periods from 2008. The figure demonstrates that averaging periods smooth out large fluctuations in the daily prices. It also shows that the 23-month averaging period tends to smooth out fluctuations in forward prices more compared to the 12-month averaging period. Consequently, the 23-month averaging period results in lower fluctuations in 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 retail prices will take longer to decline when wholesale prices fall.

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. As Figure 3.1 shows,

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

[22] AEMC, 2018, p 21.

[23] ESC, 2019, p 24.

[24] ESC, 2019, p 24.

[25] QCA, 2018, p 13.

the area under the lines of 23-month and 12-month averaging periods is the same. This implies that the total costs to consumers under both averaging periods is unchanged.

The ACTCOSS in its submission noted that consumers prefer price stability in the context of significant price rises but would value early pass through of price reductions rather than smoothing these out over a longer timeframe. The Commission acknowledges consumers' preferences noted in the ACTCOSS submission. The Commission nevertheless notes that it's regulatory decision on the averaging period should be symmetrical for both prices rises and price falls. Asymmetry in regulatory decisions can negatively affect the retailer's recovery of efficient costs associated with energy purchases and, consequently, its financial viability. As Figure 3.1 shows, faster access to lower prices also means faster prices increases when wholesale prices increase.

Frontier Economics acknowledged this in its report that the preferred averaging period can be chosen to reflect the Commission's regulatory objectives.[26]

Figure 3.1 ASX futures market data from 2008 to 2018

Source: ASX data

The Commission notes that consumers who prefer to have their electricity bills more reflective of higher price volatilities can choose a market offer over a standing offer (the standing offer is based on more stable regulated prices).

On balance, the Commission considers it appropriate to maintain a more stable regulated price than an alternative. The Commission's draft decision is to continue to apply a 23-month averaging period for the forward price calculation.

[26] Frontier Economics, 2019, p 32.

Alternative approach to calculating an appropriate load profile

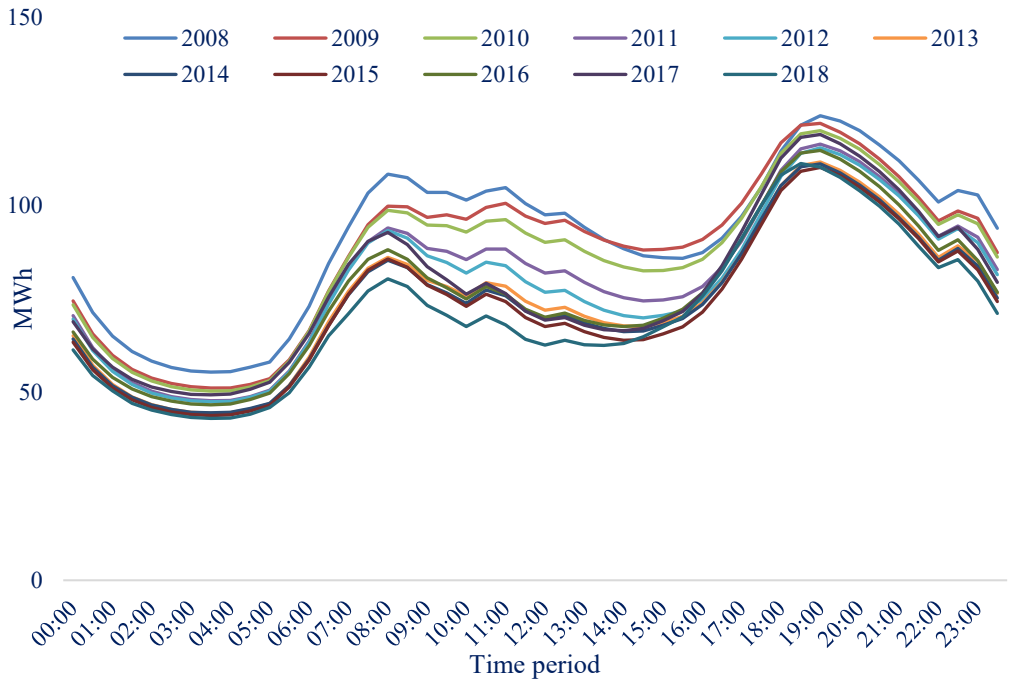
The Commission's model currently estimates the energy purchase costs based on an average historical relationship between spot prices and load since 2003–04. Frontier Economics suggested adopting a shorter period for determining an appropriate load profile for the ACT. The Commission agrees with Frontier 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.

Frontier Economics, in its analysis, derived load and spot prices using Monte Carlo simulations. A Monte Carlo simulation is used to develop a representative year using actual load data and spot prices over a period of time. The representative year is effectively an 'average' over the period, but retains the volatility present in the actual spot price and load data in each year of the period.[27]

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 (Figure 3.2) and trends in the frequency and timing of high price events (Figure 3.3) to identify representative years. The Commission found the last five years to be representative as they had typical load profiles and did not contain an abnormal number of high price events.

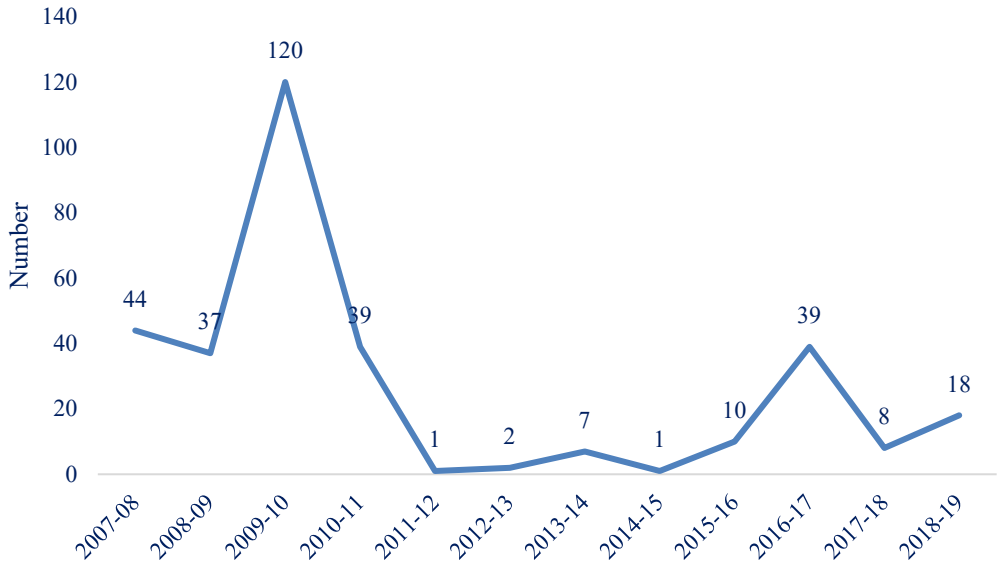
[27] In technical terms, the Monte Carlo Simulation is a statistical technique that repeatedly draws random samples of load data and spot prices from a data set comprising several years of actual historical data. A Monte Carlo simulation derives a 'representative' year of loads and associated spot prices 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.

Figure 3.2 Trends in daily demand, 2008 to 2018



Source: AEMO data

Figure 3.3 Number of high price events from 2007–08 to 2018–19



Source: AEMO data

From a cross-jurisdictional analysis, the ESC in its VDO draft decision used 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.[28] The weather-based simulations were used to reflect the fact that demand for electricity varies with weather conditions.

Should the current pricing model be retained, the Commission's draft decision is to use the five years prior to the price direction to calculate an appropriate load profile for the ACT. The current approach, by way of its construction of load shape and load ratio, retains the relationship between load data and spot prices and the associated volatilities. As such, the Commission considers that Monte Carlo simulations may not be necessary.

Should Frontier Economics' recommended approach be adopted, the Commission's draft decision is to use a Monte Carlo simulation to generate a 'representative' year of loads and spot prices using actual data from the most recent five financial years prior to the price direction. This is consistent with the approach proposed by the ESC for its draft VDO. The QCA's 2018–19 approach also relied on simulations to generate load data.

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 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. The cost of holding this working capital is known as a volatility allowance.

The Commission's current energy purchase cost model provides an allowance for volatility through two mechanisms. First, the load ratio used in the uplift factor is the maximum load ratio from 2003-04, rather than the average load ratio. Second, a value of 0.1 is added to the load ratio in the uplift factor. From the Commission's most recent determination, these two factors caused the EPC to increase by $0.53 per MWh in 2018–19, which compensated the retailer for larger than expected volatility in wholesale energy costs.

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.[29] The resulting volatility allowances for the five distribution zones in Victoria for 2019–20 range from $0.12 MWh to $0.18 MWh.[30]

[28] ACIL Allen, 2018, p 3.

[29] ESC, 2019, p 25.

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

Should the Commission adopt Frontier Economics' recommended approach to the hedging strategy, an alternative way of allowing for the residual risk of high volatility is to take this risk into account in determining the heuristic for the benchmark contract position. As noted above, the precise heuristic will be determined during the next retail electricity price investigation.

Cost of carbon

The cost of carbon is set at zero in the current energy purchase cost model. As noted in the Commission's issues paper, an alternative would be to remove the carbon cost component from the model.

The Commission received no submissions on the carbon cost component.

Both approaches are straightforward and do not involve complex model manipulations. As the outcome in either case would be the same, the Commission proposes to leave the model unchanged, which includes setting the carbon cost equal to zero.

3.2 National green scheme costs[31]

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 Large-scale Generation Certificates (LGCs) and Small-scale Technology Certificates (STCs) to the CER in percentages set by regulation each year.[32]

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 AAR's 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

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

[32] 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.

faced by the retailer. The Commission sources LGC and STC daily spot price data from ICAP.[33]

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 The matters raised in the issue paper

In the issues paper, the Commission sought feedback from stakeholders on the current methodology and the appropriateness of including a holding cost and mark-up cost and the appropriate magnitude of any such costs.

3.2.3 Issues paper submission

AAR supports 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.[34] AAR also stated that it considers that the five per cent administrative mark-up is a reasonable reflection of the costs of managing the LRET and SRES schemes on behalf of the government through retail prices.

3.2.4 Commission's draft 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.

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

[34] AAR, 2018, p 6.

To inform this review, the Commission undertook a cross-jurisdictional comparison of certificate holding and administration costs.

Cross-jurisdictional comparison

A cross-jurisdictional comparison indicates that the Commission is the only regulator that allows for the recovery of holding costs and administration costs in the green scheme cost component.

The QCA estimates LRET and SRES costs based on expected average certificate prices and the renewable energy percentages. The expected average LGC price is estimated based on a two-year average of forward-looking market prices published by the Australian Financial Market Association.[35] The expected STC price is based on the STC Clearing House Price.[36] No holding cost or administration cost is included as part of the green scheme costs. For the SRES costs, the QCA's approach includes an annual true-up to account for differences between the estimated and actual costs incurred in the previous financial year.

These SRES true ups incorporate allowances for the time value of money, an adjustment for standing offer prices already determined for the previous financial year, associated retail costs and energy losses. For example, in its 2018–19 true up, the QCA made an adjustment to reflect the time value of money proxied by a nominal weighted-average cost of capital of 8.21 per cent, a standing offer price adjustment of 5 per cent, a variable retail cost allowance of 11.27 percent and energy losses.[37]

The Office of the Tasmanian Economic Regulator (OTTER) calculates LRET and SRES costs based on the renewable energy targets and market prices for certificates. For certificate prices, the OTTER uses over the counter data published by Green Markets,[38] whereas the Commission sources data from ICAP. The OTTER's methodology does not incorporate certificate holding costs or administrative costs. The OTTER includes an annual true up to account for differences between the estimated and actual costs.

In 2013, the IPART determined LRET and SRES costs based on advice from Frontier Economics. Frontier Economics used the long-run marginal cost (LRMC) of meeting the overall national target as the LGC price.[39] For STC prices, Frontier Economics used the expected forward price or the STC Clearing House Price, whichever was

[35] ACIL Allen, 2018, p 26.

[36] The clearing house is operated by the Clean Energy Regulator with the clearing price set at $40 per STC.

[37] QCA, 2018, pp 144-145.

[38] Green markets is a research and advisory business. See http://greenmarkets.com.au.

[39] IPART, 2013, p 77.

smaller. The IPART method did not include a separate allowance for holding or administration costs in the calculation of green scheme costs.

The ESC's draft decision on the VDO price determined the LRET cost allowance by multiplying the Clean Energy Regulator's RPP and the market price for LGCs. On Frontier Economics' advice, the market price for LGCs was determined by taking a 40-day average of LGC prices as reported by Mercari. The SRES cost allowance was determined by multiplying the STP and the certificate prices. The STC prices were set at clearing house price of $40 per certificate. No holding or mark up costs were included.

Commission's draft decision

The Commission recognises that there are legitimate costs associated with holding certificates prior to a surrender date. These costs mainly relate to the financing costs associated with holding certificates up to their surrender and related administration costs.

AAR did not provide statistical information or other evidence to support its submission on holding and administration costs. The Commission has therefore been unable to assess AAR's submission against robust evidence.

The Commission's draft view is that holding costs are already accounted for in the retail operating cost allowance and therefore should not be included as part of the green scheme cost. Retail operating costs account for the efficient costs incurred by the retailer in providing retail services that include administration and finance costs. Recovering a holding cost as part of the national green cost component is likely to result in double counting of the actual costs incurred by a prudent retailer in holding certificates up to the surrender date.

Similarly, the Commission recognises that retailers face administration costs to participate in the national green scheme. According to AAR's submission, retailers participating in the national green scheme incur costs relating to certificate trading, compliance related activities and utilisation of IT systems that are unavoidable.[40] The Commission's draft view is that the administration costs associated with purchasing certificates are already accounted for in the retail operating cost allowance.

As previously noted, the QCA's approach incorporated a true-up cost allowance for the SRES costs that allows for the time value of money. In the Commission's view, the time value of money reflects the financing cost of a hypothetical efficient retailer. As noted in Chapter 4 of this draft report, the financing costs are already incorporated in the Commission's retail operating cost allowance in the administration cost category. The Commission's draft view is that a mark-up on SRES costs for the time value of money is not warranted in determining true-up costs in the Commission's model.

[40] AAR, 2018, p 6.

Calculating the national green scheme costs excluding holding and administration costs would produce an indicative value of $21.81 per MWh for 2018–19 for AAR. This is lower than the Commission's allowance of $25.19 per MWh for 2018–19.

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 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 Matters raised in the issues paper

In the issues paper, the Commission proposed that it would be appropriate to continue to use its current approach for estimating energy losses over the next regulatory period commencing 1 July 2020 as there is no alternative methodology that can be considered appropriate.

3.3.3 Issues paper submission

In its submission, AAR stated 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 energy losses was largely out of scope.

3.3.4 Commission's draft 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 loss factors calculated by the AEMO appear to be the most appropriate measure to determine the cost of energy losses. As such, the Commission's draft view 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 reflect these changes 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. Detailed analysis of each component that comprises the NEM management fees can be found in Appendix 2.

Total NEM fees make up 0.4 per cent of AAR's 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 Matters raised in the issues paper

In the issues paper, the Commission noted that it would review the current methodology to estimating the NEM fees.

3.4.3 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 only represent a relatively small proportion of 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.[41]

3.4.4 Commission's draft 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

[41] AEMO, 2018, p 2.

determining how often the Commission estimates the NEM fee component within a regulatory period. To inform the draft decision, the Commission considered methods used by regulators in other Australian jurisdictions. The sections below outline the possible methods and the Commission's draft decision.

Maintaining the Commission's current methodology

The Commission currently adjusts the NEM fee component to reflect the annual change in the CPI. The advantages of maintaining the current approach are that it is transparent, simple to understand, and straightforward to implement.

The major disadvantage of the current approach is that it is not cost reflective given that actual cost changes can be more or less than the CPI changes.

Adopting the QCA approach

An alternative to the current methodology used by the Commission would be to adopt the approach used by ACIL Allen for the QCA. ACIL Allen used the AEMO's budget and fee projections to estimate NEM management fees. Ancillary services charges were estimated using the AEMO's ancillary service payments averaged over the preceding 52 weeks.

The Commission considered that calculating ancillary fees using a 52-week averaging period would reflect recent changes in the market. AAR's submission noted that it supports using the last 12-month average as a proxy for costs in the following 12 months in determining ancillary services fees.[42]

Adopting this methodology would require the Commission to annually determine the costs of each individual component that make up NEM fees (such as general participant fees, FRC, NTP and ECA fees). It may therefore require relatively more regulatory resources to implement and review in each year of the regulatory period.

Adopting IPART's former approach

A third option is to adopt the approach used by IPART before deregulation occurred in NSW in 2015. In 2013, IPART engaged Frontier Economics to calculate NEM and ancillary fees. NEM fees were calculated based on the budgeted revenue requirements of the AEMO. Ancillary fees were calculated as the average of real ancillary services costs in NSW over the past ten financial years.

This method is essentially the same as the QCA method, except that ancillary services fees are determined using a 10-year average of the NSW region AEMO published settlement data, rather than the QCA's method of 52 weeks of the Queensland region AEMO data. In the Commission's view, using a 10-year averaging period may not

[42] AAR, 2018, p 7.

reflect current market conditions, particularly when important changes have occurred over recent years (such as [to add]).

Adopt the QCA or IPART approach with annual indexation

A fourth option is to adopt either the QCA or IPART approach to determine the NEM fees at the start of the regulatory period and then apply annual indexation within the regulatory period. This approach would only require the Commission to determine the individual components of NEM fees and ancillary services fees for the first year of the regulatory period, with subsequent years of the regulatory period indexed by the CPI. The fees would be updated at the beginning of each subsequent regulatory period.

If this approach were adopted, the Commission would need to choose either the QCA's 52-week or the IPART's 10-year averaging period for determining ancillary services fees.

This option would be more cost reflective than the Commission's current approach, but less precise in reflecting actual cost changes during the regulatory period than the QCA and IPART approaches. In contrast, it would be relatively simpler, easier to understand, and less burdensome to implement than the QCA and IPART approaches.

Commission's draft decision

The Commission considers 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 using the QCA methodology to determine the individual components of the NEM fee and ancillary services fees for the first year of the regulatory period. For subsequent years of the regulatory period, this cost is indexed to the CPI.

The Commission considers that the QCA's methodology of calculating ancillary fees using a 52-week average period would better reflect recent changes in the market than the IPART's methodology, which uses a 10-year averaging period. The only difference between the QCA and the IPART methodology is the choice of the averaging period used to calculate ancillary services fees.

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

Applying the AEMO's estimated costs, the proposed method would produce an indicative value of $1.13 per MWh for 2020–21. Indexing this figure by an estimated increase in CPI of 2.5 per cent would produce values of $1.16 and $1.19 per MWh for 2021–21 and 2022–23, respectively (Table 3.1). The allowance resulting from the proposed methodology is slightly higher than the Commission's allowance of $0.90 per MWh for 2018–19.

Table 3.1 Estimated NEM fees using the proposed approach of applying the AEMO's data for 2020–21 and indexation from 2021–22 to 2022–23 ($/MWh)

	2020–21	2021–22	2022–23
NEM management fees	0.56	n.a.	n.a.
Full retail contestability fees (FRC)	0.08	n.a.	n.a.
National Transmission Planner fees (NTP)	0.03	n.a.	n.a.
Energy Consumers Australia fees (ECA)[a]	0.06	n.a.	n.a.
Ancillary services fees (NSW region, 52 weeks)[b]	0.40	n.a.	n.a.
Total NEM fees	**1.13**	**1.16**	**1.19**

Notes: a ECA fees are determined by multiplying the number of connection points by $0.00985, multiplying the resulting figure by 52 weeks, and then dividing the resulting figure by total energy usage. The figure was calculated using AAR's 2018–19 estimated customer numbers and estimated electricity usage. The same estimate is used as a proxy for 2019–20 to 2022–23.

b 2018–19 values are used for years 2019–20 to 2022–23 as forecast ancillary services settlement data is not available.

Sources: Commission's calculations and AEMO (2018).

3.5 Energy contracting costs

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

Energy contracting costs make up 0.4 per cent of AAR's 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 Matters raised in the issues paper

In the issues paper, the Commission noted that it would review this component as part of retail operating costs.

3.5.3 Issues paper submissions

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

3.5.4 Commission draft decision

The Commission expects that a hypothetical efficient retailer would maintain a trading desk for purchasing electricity. In reality, whether this is the case depends on the size and structure of the retailer. In practice, some retailers will operate a trading desk while others may outsource the management of their energy purchasing and hedging activities to a third party.

The Commission considers that energy contracting costs are part of administrative costs. The costs associated with administration have already been incorporated in the Commission's retail operating cost allowance (see section 4.1.1 of Chapter 4 of this report). As such, recovering energy contracting costs as a separate allowance may result in double counting.

The Commission's draft 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 AAR's 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.[43] Prior to this, retail operating costs were determined using a bottom-up approach, benchmarking and indexation to the CPI.[44]

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.

The Commission considers that the energy contracting costs (i.e., the costs of manging an electricity trading desk) are part of administrative 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 Matters raised in the issues paper

In the issues paper, the Commission sought feedback on the scope of retail activities included in the Commission's current retail operating cost allowance, whether the Commission's current approach for setting this allowance remains appropriate, and what alternative approaches should be considered in this Review.

[43] ICRC, 2014, p 54.

[44] ICRC, 2003, p 13.

The Commission noted that it would monitor evolving regulatory practice and consider findings and information from recent Australian Competition and Consumer Commission (ACCC) and other regulatory investigations, evolving jurisdictional approaches, and other relevant information in making its decision. It also noted that it would consider the inputs required to implement its methodology in the next price investigation.

4.1.3 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:

- 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.

4.1.4 Commission's draft decision

The Commission's current approach, using a hybrid of bottom-up and benchmarked costs, is long-established,[45] has been widely consulted upon,[46] and provides substantial 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 from AAR in three information requests, made on 5 and 10 October 2018 and 11 February 2019.[47] These information requests sought retail cost data and supporting information that AAR provided to the ACCC for its 2018 Retail Electricity Pricing Inquiry. The AAR provided the Commission with the requested information as well as additional explanation to assist the Commission.

In making its draft decision, the Commission has used the information provided by AAR to confirm that the cost categories included in the Commission's retail operating cost component accurately reflect the types of costs incurred by AAR in supplying retail electricity services to small customers in the ACT.

While AAR has provided detailed cost information to the Commission on a confidential basis in accordance with its information requests, the Commission has not used this information to make decisions about the magnitude of an efficient retail operating cost allowance. The purpose of this Review is to determine the methodology

[45] ICRC, 2003, pp 12–13.

[46] ICRC, 2017, pp 25–29.

[47] The information requests are available on the Commission's website.

the Commission intends to use in its next price investigation. During its next price investigation, the Commission will seek information from AAR and from other stakeholders on the cost inputs for determining an efficient retail operating cost allowance.

The remainder of this section discusses the Commission's views on the two adjustments to the methodology proposed by AAR and notes current developments that it expects will inform the future implementation of the methodology.

Customer acquisition and retention costs

The ACCC, in its REPI report, defines CARC as the costs of acquisition channels (for example, third party comparison websites, door-to-door sales, telemarketing), other marketing spend, retention teams and related costs.[48]

The Commission has considered whether to include an allowance for CARC in the ACT and has made a draft decision that it 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. The ACT retail electricity market is characterised by little competition and a high proportion of customers on standing offers.

The Commission's draft position 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.[49]

Economies of scale

AAR continues to dominate the ACT retail electricity market in terms of customer numbers (88 per cent as of 2018).[50] The Commission's assessment is that AAR's position as the dominant retailer in the ACT with a stable customer base reduces any potential cost disadvantages associated with lower economies of scale. From the ACCC's 2018 report, there is no consistent evidence to suggest that economies of scale affect retail operating costs. The report noted that vertically integrated retailers with strong balance sheets and a stable customer base can achieve economies of scale.[51] The report also found that some smaller retailers have much lower costs to serve (i.e., retail

[48] ACCC, 2018, p 221.

[49] ACCC, 2018, p 249.

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

[51] ACCC, 2018, p 137.

operating costs) per customer than some of the large retailers (including some of the big three).[52] Further, the report 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.[53] AAR has more than 200,000 customers.[54]

Implementation of the methodology in the next price investigation

Based on the currently available information, the Commission considers that the current methodology for calculating the retail operating cost allowance is reasonable and reflects current best practice.

The Commission notes that the work currently being undertaken by other Australian regulators may provide insights and benchmarking information on retail operating costs that could inform the inputs for the Commission's methodology.

The AER is currently determining a default market offer (DMO) price for the jurisdictions and distribution zones where prices are not regulated. The AER released its draft determination in February 2019 and expects to release its final determination in April 2019. In its draft decision, the DMO price (presented as estimated annual bills for representative residential and business consumers) was estimated using a top-down approach based on publicly available data on market and standing offers.

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 [55] 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.[56] 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.[57]

The ESC released its draft determination on the VDO in March 2019. It allowed a retail operating cost allowance of $104.50 per customer for 2019–20 plus a CARC allowance of $51.48 per customer.[58] The ESC used a benchmarking approach for estimating retail operating costs and considered ACCC's 2018 findings, market data,

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[52] ACCC, 2018, p 224.

[53] 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.

[54] ACCC, 2018, p 224.

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

[56] ACCC, 2019, p i.

[57] ACCC, 2019, p 50.

[58] ESC, 2019, p 49.

data provided by stakeholders and recent regulatory decisions in making the draft decision. to the ESC's consultant, Frontier Economics, found that retail operating costs used in regulatory decisions made since 2013 fell within a range of $122 to $129 per customer. In estimating a modest allowance for CARC, as required by its terms of reference, the ESC used the ACCC's 2018 report findings.

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 AAR's 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. [59] 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.[60]

In making this decision, the Commission noted that the figure was at the lower end of the range estimated by SFG.[61]

4.2.2 Matters raised in the issues paper

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.

[59] IPART, 2013, p 94.

[60] ICRC, 2017, p 36.

[61] SFG, 2013, pp 5–15.

4.2.3 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.[62] 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.[63]

4.2.4 Commission's draft decision

The Commission proposes to continue to adopt a benchmarking approach to determine the retail margin. The inputs used to determine the retail margin will be informed by ongoing regulatory investigations and analyses by national and state regulators. 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 retail arm of businesses will not be released until its second report in six months' time.[64] 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 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 Frontier Economics.[65] 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 about using an ex-post rather than ex-ante margin, the Commission notes that SFG estimated a feasible range for the retail margin using three approaches: an expected returns approach, benchmarking approach and bottom-up approach. On an ex-ante basis, the SFG's recommended 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.

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[62] 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.

[63] AAR, 2018, p 10.

[64] ACCC, 2019, p 50.

[65] 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).

The Commission will continue to monitor ongoing ACCC and other regulatory investigations, evolving jurisdictional approaches, and other information relevant to informing its 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 AAR's total costs for 2018–19.

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 Matters raised in the issues paper

The Commission considered that it would be appropriate to maintain its current approach for estimating EEIS costs for the next regulatory period commencing 1 July 2020.

4.3.3 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.

4.3.4 The Commission's draft decision

The EEIS compliance costs are determined based on the energy saving obligations as set out in the EEIS legislation[66] 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.

[66] https://www.environment.act.gov.au/energy/smarter-use-of-energy/energy_efficiency_improvement_scheme_eeis/legislation.

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

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 AAR's total costs for 2018–19.

5.1 Current approach

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

5.2 Matters raised in the issues paper

The Commission considered that it would be appropriate to maintain the current approach for the next regulatory period.

5.3 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.

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

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.

- 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 are appropriate to use for the ACT as they are specific to Queensland.
- States that if the ICRC decides to adopt the Frontier 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.

Appendix 2 NEM fee analysis

NEM management fees

To determine NEM management fees the AEMO identifies costs that it considers directly attributable to key NEM outputs and indirect costs it considers to be assigned to a NEM function.[67]

Forecast and actual NEM management fees are published by the AEMO annually as part of its electricity functions final budget and fees report.[68] Table A2.1 shows NEM management fees from 2017–18 to 2021–22, as per the latest budget and fees report.

Table A2.1 Estimated NEM management fees 2017–18 to 2021–22, ($/MWh)

	Actual 2017–18	Budget 2018–19	Estimate 2019–20	Estimate 2020–21	Estimate 2021–22
NEM management fees	0.41	0.44	0.50	0.56	0.62

Source: AEMO (2018).

Full retail contestability fees

The purpose of the Full Retail Contestability (FRC) component of the NEM fees is to facilitate retail market competition in the southern states and the east coast of Australia. It does this by managing and supporting data for resettlement purposes, customer transfers, business to business processes and market procedure changes.

The AEMO currently collects FRC fees from market participants on a MWh energy consumed basis.[69] Table A2.2 shows the AEMO's FRC fees from 2017–18 to 2021–22.

Table A2.2 Estimated FRC fees 2017–18 to 2021–22, ($/MWh)

	Actual 2017–18	Budget 2018–19	Estimate 2019–20	Estimate 2020–21	Estimate 2021–22
Full retail contestability fees (FRC)	0.075	0.077	0.080	0.082	0.085

Note: The MWh basis is shown after July 2019 to demonstrate the fee trend.

Source: AEMO (2018).

National Transmission Planner fees

[68] AEMO, 2018.

[69] From 1 July 2019 this methodology will change, and fees will be collected on a per connection basis (AEMO, 2018, p 10).

The National Transmission Planner (NTP)'s primary role is to prepare and publish the National Transmission Network Development Plan, which outlines the current and expected future capability of the national transmission network and development options, with the aim of promoting the long-term, efficient development of the power system.

The NTP fee is charged to market customers and levied at a rate per MWh based on AEMO's estimate of total MWh to be settled in spot market transactions by market customers during that financial year. The rate is applied to actual spot market transactions in the billing period. Table A2.3 shows the AEMO's estimates for NTP fees from 2017–18 to 2021–22. The AEMO notes that the constant seven per cent increase from 2019–20 through to 2021–22 reflects the need for additional resources and investment required to improve forecasting, planning and preparation of the AEMO's Integrated System Plan.[70]

The AEMO's NTP fee for 2018–19 is $0.0234 per MWh.

Table A2.3 Estimated National Transmission Planner fees 2017–18 to 2021–22, ($/MWh)

	Actual 2017–18	Budget 2018–19	Estimate 2019–20	Estimate 2020–21	Estimate 2021–22
National Transmission Planner fees (NTP)	0.0213	0.0234	0.0250	0.0268	0.0287

Source: AEMO (2018).

Energy Consumer Australia fees

On 13 December 2013 the Council of Australian Governments agreed to establish a national energy consumer advocacy body as part of a package of energy market reforms agreed by State and Territory Energy Ministers in 2012. Energy Consumers Australia (ECA) was formally established on 30 January 2015 and assumed the responsibilities of the former Consumer Advocacy Panel, which was subsequently closed.

As defined in the National Energy Retail Law, ECA fees are levied on a per small customer connection point basis. Table A2.4 shows the AEMO's ECA fees for 2017–18 and 2018–19 per connection point for small customers per week.

Table A2.4 ECA fees for 2017–18 and 2018–19 (per connect point, per week)

	Actual 2017–18	Budget 2018–19
Energy Consumers Australia fees (ECA)	0.00979	0.00985

Source: AEMO (2018).

[70] AEMO, 2018, p 13.

NEM fee methodologies of other jurisdictions

QCA

The QCA determined 2018–19 NEM fees and ancillary service charges based on advice from ACIL Allen. ACIL Allen used the AEMO's 2017–18 fee projections to estimate general participant, FRC, NTP and ECA fees. Ancillary service charges were estimated using the AEMO's ancillary service payments averaged over the preceding 52 weeks. ACIL Allen used customer numbers to estimate the cost of ECA requirements in $/MWh.

The QCA determined total NEM fees of $0.96 per MWh for 2018–19 (Table A2.5).

Table A2.5 The QCA's total NEM fees for 2018–19

	NEM fees ($/MWh)
NEM management fees (also known as 'general participant' fees)	0.41
Full retail contestability fees (FRC)	0.07
National Transmission Planner fees (NTP)	0.02
Energy Consumers Australia fees (ECA)	0.03
Ancillary services fees (Queensland region, 52 weeks)	0.43
Total NEM fees	**0.96**

Note: For its 2018–19 calculation, the QCA has used the figures published in the AEMO's Electricity Final Budget and Fees 2017–18.

Sources: ACIL Allen (2018) as cited in QCA (2018).

IPART

The IPART engaged Frontier Economics in 2013 to calculate NEM and ancillary services fees. NEM fees were determined based on the budgeted revenue requirements of the AEMO as published in its electricity final budget and fees 2013–14 report. Ancillary services fees were estimated using the AEMO's ancillary services charges in NSW averaged over the past ten financial years. The IPART chose a ten-year averaging period on the advice of Frontier Economics that using a longer period will avoid the risk that the result is affected by an outlier.[71] The main methodical difference in calculating ancillary services fees between the IPART and the QCA is the ten-year and 52-week averaging period, respectively.

The IPART determined total NEM fees of $1.04 per MWh for 2013–14 (Table A2.6)

[71] IPART, 2013, p 86.

Table A2.6 The IPART's total NEM fees for 2013–14

	NEM fees ($/MWh)
NEM fees[a]	0.35
Ancillary services fees (NSW region, 10 years)	0.69
Total NEM fees	**1.04**

Note: [a] These fees are referred to as 'Market fees' in the Frontier Economics report. A detailed breakdown of costs is not available.

Sources: Frontier Economics, cited in IPART (2013).

NEM fee cost components using the methodology of other jurisdictions

Adopting the QCA approach

Applying the QCA's methodology and using the AEMO's 2018–19 final fees would produce an estimated allowance of $1.00 per MWh for AAR for 2018–19 (Table A2.9).

Table A2.7 Estimated NEM fees using the QCA's methodology ($/MWh)

Cost category	2018–19	2019–20	2020–21	2021–22
NEM management fees	0.440	0.500	0.560	0.620
Full retail contestability fees (FRC)	0.077	0.080	0.085	0.089
National Transmission Planner fees (NTP)	0.023	0.025	0.029	0.031
Energy Consumers Australia fees (ECA)[a]	0.061	0.061	0.061	0.061
Ancillary services fees (NSW region, 52 weeks)[b]	0.399	0.399	0.399	0.399
Total NEM fees	**0.999**	**1.064**	**1.133**	**1.199**

Notes: [a]ECA fees are determined by multiplying the number of connection points by $0.00985, multiplying the resulting figure by 52 weeks, and then dividing the resulting figure by total energy usage. The figure was calculated using AAR's 2018–19 estimated customer numbers and estimated electricity usage. The same estimate is used as a proxy for 2019–20 to 2021–22.

[b]2018–19 values are used as a proxy for 2019–20 to 2021–22.

Sources: Commission's calculations and AEMO (2018).

Adopting the IPART approach

Applying the IPART methodology and using the AEMO's 2018–19 final fees would produce an estimated allowance of $1.00 per MWh for AAR for 2018–19 (Table A2.10).

Table A2.8 Estimated NEM fees using the IPART's methodology ($/MWh)

Cost category	2018–19	2019–20	2020–21	2021–22
NEM management fees	0.440	0.500	0.560	0.620
Full retail contestability fees (FRC)	0.077	0.080	0.085	0.089
National Transmission Planner fees (NTP)	0.023	0.025	0.029	0.031
Energy Consumers Australia fees (ECA)[a]	0.061	0.061	0.061	0.061
Ancillary services fees (NSW region, 6 years)[b]	0.401	0.401	0.401	0.401
Total NEM fees	**1.002**	**1.067**	**1.094**	**1.121**

Notes: [a]ECA fees are determined by multiplying the number of connection points by $0.00985, multiplying the resulting figure by 52 weeks, and then dividing the resulting figure by total energy usage. The figure was calculated using AAR's 2018–19 estimated customer numbers and estimated electricity usage. The same estimate is used as a proxy for 2019–20 to 2021–22.

[b]Six years of ancillary services settlement data has been used as 10 years of data was not available from the AEMO at time of publication. 2018–19 values are used for years 2019–20 to 2021–22 as forecast ancillary services settlement data is not available.

Sources: Commission's calculations and AEMO (2018).

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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