AUSTRALIAN COMPETITION & CONSUMER COMMISSION

Inquiry into the National Electricity Market

December 2023 Report

1 December 2023

Acknowledgement of country

The ACCC acknowledges the traditional owners and custodians of Country throughout Australia and recognises their continuing connection to the land, sea, and community. We pay our respects to them and their cultures; and to their Elders past, present and future.

Australian Competition and Consumer Commission
Land of the Ngunnawal people
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ACCC 12/23
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Executive Summary

As Australia transitions to predominantly sourcing electricity from renewable energy generation in an effort to reduce greenhouse gas emissions, the National Electricity Market (NEM) will need to continue to evolve. The NEM is comprised of:

- a wholesale electricity spot market, where generators sell electricity to retailers at prices that can vary enormously to reflect supply and demand at a given point in time
- a hedging contract market, where retailers and generators contract to reduce their financial exposure to high (or low) wholesale spot market prices
- a retail market, where retailers sell electricity to consumers, with a range of cost components contributing to customer bills.

Prices paid in both the spot market and hedging contract market determine the wholesale costs that ultimately flow through to customer bills. As coal power plants exit the market, spot market prices are expected to be increasingly driven by weather conditions, changing the financial risks faced by retailers. In this context, it is critical the conditions for competition are supported throughout the energy transition and that regulatory settings are fit-for-purpose to provide consumers access to competition, and at the same time, protect consumers from unduly high prices given electricity is an essential service. Effectively balancing these objectives is difficult, particularly in light of persistent challenges in engaging a significant portion of consumers in the market. In seeking to achieve an effective balance it is important to examine the drivers of this lack of engagement.

Effective competition in the retail market is in the long-term interests of consumers, as it puts downward pressure on retail prices and encourages a greater variety of products and services. Given smaller, newer retailers play an important role in driving competition in the market, it is crucial that barriers for retailers entering the market, and existing retailers expanding their customer base, are not too high as the energy transition unfolds.

As part of the Australian Competition and Consumer Commission's (ACCC) inquiry into the NEM, this report examines the current state of competition in the retail electricity market, the ability of retailers to effectively manage their wholesale spot price risk, retail pricing and retailer pricing strategies, and the effectiveness of the market in delivering outcomes for customers.

The ACCC considers that reform is needed to improve the conditions for competition in retail electricity markets to deliver better outcomes for consumers. This report makes 4 recommendations to:

- ensure consumers remain protected and are supported to engage in the market, and
- facilitate access to contracts, particularly for standalone retailers who do not have significant generation assets, to enable competition throughout the transition.

To inform our analysis in this report, we used our compulsory information gathering powers to obtain commercially sensitive data from market participants (generators and retailers) on retail electricity prices, costs incurred by retailers to supply electricity, and electricity hedging contracts. We also engaged Frontier Economics to prepare a report on the long-term evolution of the contract market and whether it can continue to appropriately support retailers' ability to manage risk in the future.

The market volatility of mid-2022 is flowing through to retailers' costs

In mid-2022, conditions in international and domestic energy markets drove wholesale electricity prices to historic levels. This culminated in the wholesale spot market in all regions of the NEM being suspended in June 2022. Although spot and contract prices have moderated since 2022, including significant drops in contract prices following the announcement of gas and coal price caps in December 2022, they remained elevated for much of 2022–23 compared to early 2022.

This report provides our first full year of cost stack data following the market volatility of mid-2022. While it can take time, sometimes years, for spot and contract price changes to flow through to retailers' actual wholesale costs, then retail prices, and finally to consumers bills, we can observe the impacts of these high and volatile wholesale prices and other supply-side conditions on retailers' costs in 2022–23.

Short and long-term changes to wholesale markets are increasing the components that make up consumers' bills and also contributing to rising complexity in the retail market. This makes it challenging for consumers' to successfully navigate the market to achieve good outcomes.

Retailers' wholesale costs rose by 25% per residential customer and 28% per small business customer (nominal) across the NEM, as the effects of spot price spikes during mid-2022, elevated contract prices, and higher generation fuel costs flowed through to retailers' costs. Despite overall increases, wholesale costs declined in Victoria due to a range of factors including differences in wholesale market conditions, vertically integrated retailers' approaches to pricing of internal sales (known as 'transfer pricing') and individual retailer risk-management decisions.

Rising wholesale costs drove an overall increase in the average annual cost to supply electricity of 7.2% for residential customers and 11.8% for small business customers from 2021–22 to 2022–23 (in nominal terms) and contributed to rising retail prices. Wholesale cost increases mean they now represent 33% of an average retailer's annual costs to supply electricity to a residential customer (up from 28% in 2021–22).

Retail margin results were mixed between regions and customer groups, with increases in most regions for both residential and small business customers. For residential customers across the NEM, retail margins declined from last year, driven largely by reductions in New South Wales. Meanwhile, increases in retail margins in South Australia and Queensland in 2022–23 largely offset longer-term reductions.

Retail margins in the NEM have now declined from making up 8.9% of an average retailer's residential cost stack in 2016–17 to 2.3% in 2022–23. For small business customers, retail margins increased in 2022–23 but remained lower than in 2020–21.

Alongside declining retail margins and retail costs over the longer-term, we can observe that market concentration has declined, and the number of active retailers has increased. These measures demonstrate positive signs for competition in retail electricity. However, recent results show these indicators appear to be plateauing. The ACCC will continue to monitor these trends, and how retailers' costs and margins shift as the retail market structure evolves.

New analysis evidences considerable consumer disengagement

For the first time in this inquiry, we collected retail prices to understand how retailers are changing prices for their existing customers on market retail contracts (or plans).

Our analysis of retail pricing allows us to see how retailers have sought to recover higher wholesale costs, by focusing on retailer pricing decisions, which align with the date of application of the Default Market Offer and Victorian Default Offer at the beginning of the 2023–24 financial year.

In New South Wales, Victoria, South East Queensland and South Australia, the majority of customers are on plans with prices which are determined by retailers (about 90% of residential customers and 80% of small business customers are on market retail contracts).

To understand price movements in the market, market bodies and regulators typically rely on analysing publicly observable prices (usually acquisition offers in Energy Made Easy and Victorian Energy Compare available to consumers who are switching product or provider or establishing a new account). However, prices for retailers' existing customers are not publicly observable, obscuring pricing outcomes for customers who are on plans that have been withdrawn from the market (legacy plans) relative to current acquisition offers.

For our new retail pricing analysis, we have analysed how prices for existing customers in our sample compare with default offer prices, as well as publicly available offers on government comparison websites.

Our sample is comprised of flat rate plans for over 5 million existing residential customers on market retail contracts. Assuming achievement of conditional discounts, we found that, in August 2023:

- 47% of residential customers were on plans with a calculated annual cost equal to or higher than the default offer
- 42% of concession customers were on plans with a calculated annual cost equal to or higher than the default offer
- 79% of residential customers could achieve a better offer if they switched to a competitively priced acquisition offer in Energy Made Easy or Victorian Energy Compare.

The percentage of customers who could achieve a better offer is particularly concerning as many customers may not even know they are on high priced plans. These results also reveal that the default offers do not constrain prices for existing customers, unlike competitive acquisition offers. While the default offers aim to facilitate competition by setting a reference price that enables engaged customers to compare offers, many consumers remain disengaged, or may face barriers to engaging in the market (for instance, literacy or language barriers).

Despite reforms, large conditional discounts persist

Concerningly, 96% of residential customers on plans with an unconditional price more than 25% above the default offer were on a plan with a conditional discount in 2023.

In 2020, additional regulation was introduced to limit the size of conditional discounts. These regulatory changes applied prospectively to contracts entered into from 1 July 2020 and were made in response to concerns about the significant financial penalties faced by consumers who failed to achieve their conditional discounts. Conditional discounts were also found to make it hard for consumers to accurately compare plans, as discounts were applied to uneven underlying prices.

In our sample, the customer-weighted average conditional discount for customers on plans with an unconditional price more than 25% above the default offer is 29%, indicating they have not changed plan or retailer in the last 3 years, when conditional discount regulation was introduced.

When we assume conditional discounts are achieved, customers with large conditional discounts are still paying prices around the default offer prices and would pay a premium if they did not achieve their conditional discount, suggesting that these customers would benefit from switching energy plan.

High conditional discounts could be inhibiting switching as customers become attached to their 'discount,' and are potentially unaware it is off an inflated underlying price. In fact, many customers may be able to save money by switching to a plan with cheaper prices, even if it means accepting a smaller, cost-reflective, pay on time discount (or none at all). Our most recent billing data shows that non-achievement of conditional discounts continues, with almost a quarter of hardship customers failing to achieve their conditional discounts for the third quarter of September 2022. This is concerning, given the high level of conditional discounts we have observed and the effective price penalty for customers who fail to achieve their discount.

Market participants can currently meet their minimum risk management needs

In addition to analysing retailers' costs, and pricing outcomes for existing customers, this report examines the short-term conditions in the hedging contract market and retailers' ability to manage spot-market risk in the future.

The uncertainty and variation in the wholesale spot price creates a risk for retailers of facing high prices and creates a risk for generators of facing low or even negative prices. As a way of managing this risk, retailers and generators can enter into hedging contracts.

Electricity hedging contract prices have moderated since the high prices seen in 2022, although they have not returned to pre-2022 levels.

Trading activity has been subdued across most regions since mid-2022, with volumes traded since then generally at or below recent years. Many generators have reported a change in their approach to selling or offering hedging contracts in the period after August 2022, with more sales decreasing than increasing. Decreasing sales could be a result of spot-market risk changing as the energy transition progresses. The market volatility seen in 2022, which highlighted the changing risk environment, may have resulted in decreased tolerance for spot-market exposure, as well as unexpected outages, and generators seeking to sell fewer contracts.

Generators and retailers were able to access the hedges they required to meet their minimum risk management requirements from August 2022 to July 2023, predominantly relying on traditional hedging products (swaps and caps). New contract products, such as solar shape and super-peak products, are currently rarely traded.

Most small retailers still cannot access the ASX

Some small retailers are experiencing difficulties executing their target hedging strategies, with most still unable to access Australian Securities Exchange (ASX) hedges. Many small retailers would prefer to access the ASX and approximately 44% of those surveyed believe they cannot effectively manage spot market price risk without ASX hedges.

While most small retailers can meet (and have met) their minimum risk management needs in the over-the-counter (OTC) market, many have reported challenges in negotiating contracts OTC. Challenges reported include difficulty engaging in discussions with suitable counterparties, contracts being offered on what they consider to be on unreasonable terms, and potential counterparties not offering contracts at all.

A third of small retailers we surveyed indicated that obtaining hedges is a significant barrier to increasing their customer base. Lack of access to the ASX has the potential to impact small retailers' ability to effectively compete to acquire new customers. Dependence on the OTC market likely places practical limits on when and how much a retailer trades, creating a barrier to retailers growing beyond a certain size. The challenges currently faced by small retailers obtaining OTC contracts raise further concerns that competition could be significantly impacted if market conditions worsen.

The energy transition will transform the contract market

As the NEM transitions to generate electricity from predominantly variable renewable generation assets, there is likely to be greater price volatility in the spot market, driven by weather conditions and the development of storage. The energy transition will transform the contract market, changing the economic incentives of hedging, the sources of contracts and the demand for new types of contracts.

As coal power plants retire, there will likely be a reduction in the number of generators that can offer traditional contract types, such as flat swaps. Retailers' need for products that guarantee prices at all times of day is also likely to reduce, as typical spot prices during the middle of the day continue to drop with increased solar penetration. It is therefore likely that there will be a change to both the demand and supply of traditional hedging products.

Hedging products currently available on the ASX are likely to be poorly suited to managing risk in the future. There is a dilemma, as the ASX may be unable to list new products without sufficient demand, but sufficient demand may not arise if new products are not available on the ASX. There may be a role for government in addressing this issue.

Retail competition is at risk without contract market reform

Small standalone retailers and new entrants may find it increasingly difficult to manage spot market price risk in the future. This is concerning because small standalone retailers play an important role in the market, with their best offers generally competitive with the best offers offered by larger retailers, putting downward pressure on prices (for new customers).

Firm power from renewables may be achieved through the combination of storage and generation assets working together across large geographical areas. In this environment, standalone retailers will need to source a wide variety of contract types from many counterparties, in a way that guarantees them stable wholesale electricity prices. This complexity will have a greater impact on small and new entrant retailers and may become unmanageable if new hedging products and alternative risk management tools, such as virtual power plants and demand response technologies, do not emerge in advance of the changing financial risks.

If vertical integration becomes increasingly used to effectively manage financial risk, this may prevent new retailers from entering the market who are unlikely to possess the credit rating required to finance large capital assets. However, this risk may be mitigated if small and new entrant retailers are able to source cost-effective storage solutions that match their load profile and risk exposure, such as small-scale solar plants and community batteries. There is also the potential for more retailers to pass some of the wholesale market price risk through to customers, many of whom may be unable or unwilling to navigate this risk.

There is no guarantee that the reduction in the supply of traditional hedging contracts will be replaced by similar volumes or types of contracts from new renewable generators in a timely manner. Government support of renewable assets risks exacerbating this by eliminating the need for generators to sell contracts to retailers to recover their costs of investment. Government measures may be needed to ensure that small and new-entrant retailers have access to hedging contracts while the contract market adapts.

Recommendations

The ACCC considers that reform is needed to improve the conditions for competition in retail electricity markets to deliver better outcomes for consumers. This report makes 4 recommendations to:

- ensure consumers remain protected and are supported to engage in the market
- facilitate access to contracts to enable competition throughout the transition.

Chapter 3: Retail pricing

Giving consumers price certainty and addressing legacy plans with large conditional discounts

For many consumers, choosing an electricity provider and product is a 'set and forget' task, which means retailers compete at the point of acquisition, but are not incentivised to keep prices for existing customers competitive. As set out in section 3.5, we found that consumers who do not regularly engage in the market experience higher prices.

This is the case for a significant number of customers who remain on plans with large conditional discounts and high underlying prices. This is despite the introduction of further restrictions on conditional discounts in 2020 by the Australian Energy Market Commission and Essential Services Commission of Victoria, which were not applied to existing contracts (as discussed in section 3.4) and only applied to new contracts entered into after the commencement of the new rules.

When consumers do engage with the market, it is not uncommon for their prices to increase not long after they sign up to a new plan. Under the National Energy Retail Law and Rules, retailers are able to offer ongoing market retail contracts and increase prices at any time with at least 5 days' notice to consumers.

This type of conduct increases switching costs for consumers and may reduce consumer confidence in the market. Our analysis suggests that retailers recoup their costs over a customer's lifetime, by setting attractively low acquisition offers and making subsequent unilateral price increases for their existing customer base over time. The accrual of these price increases over time explains why so many customers are on plans at or above the default offers, especially if they are not price sensitive, or more concerningly, face barriers to engaging in the market (for instance, literacy or language barriers) and have not changed plans.

Recommendation 1

Policy makers should investigate how best to reduce the number of customers on legacy plans with large conditional discounts, as a matter of priority.

Other areas of investigation should include:

- the impact of evergreen or ongoing contracts on consumer behaviour
- whether current rules around price changes reduce price certainty and contribute to the switching burden.

Ensuring consumers remain protected and are supported to engage in the market

Electricity markets must be regulated in a way that promotes consumer trust, including by acknowledging where competition is delivering outcomes for consumers and where targeted support is needed. Our analysis shows there is a large proportion of disengaged customers on high priced flat rate plans in our sample. Of the residential customers in our sample, 79% could achieve a better offer if they switched to a competitive acquisition offer in Energy Made Easy or Victorian Energy Compare. The Default Market Offer is set with the following objectives as guiding principles:

- reduce unjustifiably high standing offer prices and continue to protect consumers from unreasonable prices
- allow retailers to recover the efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention
- maintain incentives for competition, innovation and investment by retailers, and incentives for consumers to engage in the market.[1]

A holistic review of the Electricity Retail Code, scheduled to commence in November 2024, offers one vehicle for considering whether the current communication requirements and the settings for the Default Market Offer are correctly calibrated.

For instance, time-of-use small business plans and plans with demand charges are currently excluded from the application of the Default Market Offer. Given the roll-out of smart meters and incentives for retailers to replicate network tariff structures in retail electricity prices, more customers are likely to be offered time-of-use plans and plans with demand charges by retailers. This also means that consumers on standing offers are becoming more likely to be on a plan with a demand charge and may be exposed to unreasonably high prices.

Recommendation 2

The next review of the Electricity Retail Code to be undertaken by the Department of Climate Change, Energy, the Environment and Water is scheduled to commence in November 2024.

Areas of focus should include:

- consumer disengagement and barriers to consumer engagement
- the increasing complexity of retail tariff structures
- interactions with other reforms made after the communication requirements in the Electricity Retail Code were introduced, such as the Australian Energy Regulator's Better Bills Guideline.

1 Australian Energy Regulator (AER), *Default market offer prices 2023–24: Final determination*, AER, Australian Government, 25 May 2023, p 2.

Chapter 5: Financial risk management by small retailers

Incentives to facilitate the development of new hedging contract products should be investigated

Traditional futures contracts are unlikely to meet the evolving risk profile of retailers, with more bespoke contracting becoming increasingly necessary. New products will be needed over the next 10 years to manage the higher levels of intra- and inter-day price variation that is expected during the energy transition.

Standalone retailers and new entrants may find it increasingly complex to manage spot market price risk in an environment where the sellers of contracts, and the types of contracts, will change. To navigate this complexity, standalone retailers and new entrants will require access to new hedging products. It is not clear, based on our stakeholder discussions, that new hedging products suited to the future needs of retailers and generators will be listed on the ASX by the time they are required. Trading exchanges, such as the ASX, may be reluctant to make new types of products available for trading without sufficient evidence of liquidity. Such liquidity is unlikely to emerge, if at all, until baseload generation exists in the market.

Recommendation 3

The Government should investigate, in consultation with the ASX and market participants, whether there are ways to support new hedging products being listed on the ASX in a timelier manner.

This could involve coordinating collaboration between the ASX and market participants to identify, design and list suitable products. Other examples could include funding market making incentives within the exchange, or underwriting the risk of new hedging products to reduce margin obligations for retailers until the product becomes more liquid. Some of the types of products that may needed on the exchange include super-peak products, inverse-solar products, or products that hedge the spread for storage charging and discharging.

Government-funded renewable energy projects should contribute to contract market liquidity

Federal, state and territory governments are financially supporting variable renewable energy and storage projects in an effort to meet emissions reductions and renewable energy targets. A key motivation for a generator to contract is to provide a reasonable assurance of a stable return. If government support provides a reasonable assurance of stable returns, the incentive to contract will be reduced.

Government measures may be needed to ensure that standalone and new-entrant retailers have access to hedging contracts while the market adapts. If federal, state and territory governments are financially supporting investment in renewable energy and storage projects, they can deliver greater public benefit from their investment by increasing contract market liquidity and promoting more competition in retail markets.

Recommendation 4

Governments can increase liquidity in the contract market during the transition by making more contracts available from government-supported renewable energy and storage projects.

To support retail competition, government-funded projects could support qualifying standalone and new-entrant retailers by providing priority access to a certain quantity of hedging contracts. This priority access would recognise that standalone retailers are expected to face the largest challenges in hedging risk during the transition. Such a mechanism would require appropriate safeguards to ensure that access to contracts supports retail competition.

1. Introduction

In 2018, the Australian Government directed the Australian Competition and Consumer Commission (ACCC) to hold an inquiry into prices, profits, and margins in the supply of electricity in the National Electricity Market (NEM).

Under the terms of reference for the inquiry, the ACCC has a broad-ranging remit to monitor matters in the NEM, including electricity prices faced by customers, contract market liquidity, and the effects of policy changes. Where appropriate, the ACCC will make recommendations to government on proportional and targeted actions necessary to deliver competitive and efficient electricity prices for consumers.[2]

The ACCC must report to the Treasurer at least every 6 months until the conclusion of the inquiry on 31 August 2025. In recent years, we have adopted a cycle of reporting on billing outcomes for households and small business customers in the first half of each year, and retailers' costs in supplying electricity to customers (or 'cost stack') information in the latter half of each year. In November last year, we also reported on financial electricity markets for the first time in this inquiry, including trading dynamics and barriers to accessing hedging contracts.[3] We have analysed the contract market again in this report. This report also includes analysis of retail competition and new in-depth analysis of retail prices.

1.1. Our role in electricity markets

Regulators and governments all have a role to play in ensuring safe, reliable, and affordable energy for Australian energy customers.

The ACCC's role in energy markets is in the context of the *Competition and Consumer Act 2010,* which aims to enhance the welfare of Australians through the promotion of competition and fair trading and the provision of consumer protections.[4]

The Competition and Consumer Act establishes the frameworks under which the ACCC conducts price inquiries, including this inquiry, and monitors and enforces compliance with industry codes, including the Electricity Retail Code.[5] The ACCC also enforces compliance with the Australian Consumer Law under the Competition and Consumer Act.

The Competition and Consumer Act includes general prohibitions on anti-competitive conduct and specific provisions designed to prevent misconduct in energy markets[6], including a requirement on retailers to make reasonable adjustments to their prices to reflect cost reductions.[7] The ACCC is also empowered to monitor and protect competition in markets and to take action to ensure consumers are treated fairly.

2 See Appendix A: Terms of reference.

3 Australian Competition and Consumer Commission (ACCC), *Inquiry into the National Electricity Market: November 2022 report*, ACCC, Australian Government, 8 December 2023, accessed 17 November 2023.

4 *Competition and Consumer Act 2010* (Cth) s 2.

5 Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (Cth) pt 2.

6 *Competition and Consumer Act 2010* (Cth) pt XICA.

7 *Competition and Consumer Act 2010* (Cth) s 153E.

1.2. About this report

This report provides a picture of the current state of competition in the electricity market, its effectiveness in delivering outcomes for customers, with a focus on retail pricing informed by a brand-new data set.

For the first time in this inquiry, we have collected new information from retailers to understand how retailers are changing prices for their existing market offer customers. This information includes pricing data which collectively applies to over 5 million residential customers and 400,000 small business customers on flat rate plans. Our analysis draws on this dataset to assess pricing outcomes for existing customers, and how these prices compare to new acquisition offers in the market. This new evidence base has yielded valuable insights as well as provided the most up-to-date source of pricing information (as recently as August 2023).

This is the ACCC's second report in this inquiry which examines the contract market and whether retailers can access hedging contracts. We collected information relating to the contract market from 21 electricity retailers, generators and gentailers,[8] accounting for the majority of electricity contracts traded in the NEM. Our analysis examines market dynamics such as trends in prices, volumes, and product types. The analysis also considers the period of high prices and volatility in the wholesale electricity market in mid to late 2022 and focuses on the experience of small retailers in the contract market.

To further inform our analysis of the contract market, we commissioned an independent expert, Frontier Economics, to prepare a report on future financial risk management in the NEM (see Appendix D) and whether it can continue to appropriately support retailers' ability to manage risk in the future. As an input to their report, Frontier Economics, together with representatives from the ACCC, met with a variety of industry stakeholders to seek feedback on how changes in the contract market over the next 10 years are likely to affect retailers' ability to manage wholesale spot-price risk.

We have been collecting information on and analysing retailers' 'cost stacks' since the beginning of the inquiry in 2018.[9] This analysis provides information on the components that make up retailers' annual cost to supply electricity as well their retail margins. It covers a sample of retailers that cover approximately 84% of the residential customer base in the NEM.

1.2.1. The data we collect

We used a range of data sources for this report. Most importantly are our compulsory information gathering powers under section 95ZK of the Competition and Consumer Act, which allow us to obtain information from market participants that may not otherwise be publicly available.

We issued 3 sets of section 95ZK notices requesting a variety of data, information, and documents to inform the analysis underpinning this report:

- Under the **contracts notice**, we requested qualitative data in the form of a survey about the companies' experiences in the electricity hedging market, as well as quantitative data on their forecast maximum and average load, Australian Energy Market Operator

8 A 'gentailer' is a vertically integrated generation and retail business.

9 Our collection of cost stack information under this Inquiry continued the timeseries we began collecting under our Retail Electricity Pricing Inquiry. This means we have data on retailers' costs and profits dating back to 2007–08.

prudential requirements and details of all trades taken place from 24 August 2022 to 19 July 2023.

- Under the **pricing notice**, we requested information and documents on pricing and retail practices of retailers, including information on plan level pricing, price setting policies, acquisition and retention of customers, customer tenure and approaches to product differentiation and customer value.
- Under the **cost stack notice**, we requested information on the components that make up retailers' costs to supply electricity for the period of 1 July 2022 to 31 June 2023. This includes information on wholesale, network, environmental and retail costs, and margins, as well as revenues, customer usage, customer numbers and other financial information.

The methodology appendix (Appendix B: Methodology for data collection and analysis) provides more detail on our data collection and analysis techniques for the cost stack and retail price datasets. The data appendix (Appendix C) includes many charts and tables not presented in the body of the report, including regional breakdowns and longer time series.

1.2.2. The geographic scope of our analysis

The NEM comprises New South Wales, the Australian Capital Territory (ACT), Queensland, South Australia, Victoria, and Tasmania. We examine the performance of the spot and contract markets in each of these states and territories. However, as there is one regional reference node for both the ACT and New South Wales, the ACT is included in our analysis of New South Wales market dynamics.[10] Similarly, our cost stack analysis also combines the ACT and New South Wales into one region.

We separately report Tasmania in our regional cost stack analysis, with some minor modifications to the reporting basis to protect individual retailer data in this state. In addition, there is no material contract market trading in Tasmania due to the dominance of vertically and horizontally-integrated, government-owned generators in that state. For example, no ASX contracts are available for Tasmania. As such, our analysis of Tasmania's wholesale electricity market is largely limited to the spot market.

For retail price analysis, we focus on the regions with retail competition, namely, Victoria, New South Wales, South Australia, and South East Queensland.

1.3. Structure of this report

The body of the report is structured as follows:

- Chapter 2 focuses on **market structure and retailers' costs**
- Chapter 3 focuses on **retail prices in 2022 and 2023**
- Chapter 4 focuses on **contract market outcomes**
- Chapter 5 focuses on **financial risk management by small retailers**.

[10] The regional reference node is the basis for pricing of wholesale spot and contract markets – so effectively the ACT and the NSW are one region for pricing purposes.

2. Competition and costs in retail electricity markets

Key Findings

- Our analysis shows that while measures of competitiveness in retail electricity markets have generally been improving over the longer-term, many of these indicators appear to be plateauing.
- Retail margins results were mixed between regions and customer groups. Across the National Electricity Market, margins for residential customers declined slightly to the lowest in our timeseries. Margins now represent 2.3% of an average retailer’s annual cost to supply a residential customer (down from 8.9% in 2016–17). Retail margins for small business customers rebounded from lows in 2021–22 but remain below 2020–21 levels.
- Margin results in 2022–23 for both customer groups were influenced by declining margins in New South Wales. Margins increased in all other regions for both residential and small business customers. For residential customers, retail margins in South Australia increased nearly to 2016–17 levels, while in South East Queensland, margins actually exceeded those in 2016–17.
- Changes in retail and other costs for residential customers stalled in 2022–23, following continuous declines since 2013–14.
- These trends coincide with a stabilisation in the trend of measures of retail market concentration in recent years, following declines over the longer term. Similarly, the trend of increases in the number of active retailers in the market up to 2021 has reversed somewhat since 2022 following several retailers’ exits and reduced new entrants. The ACCC will continue to monitor these trends, and how retailers’ costs and margins shift as the retail market structure evolves.
- Overall increases in retailers’ average annual cost to supply customers in 2022–23 were driven largely by increasing wholesale costs. While wholesale costs increased substantially for both residential and small business customers in most regions, they declined slightly in Victoria. The decline in Victoria was due to a range of factors including regional differences in wholesale market conditions, vertically integrated retailers’ approaches to pricing of internal sales (known as ‘transfer pricing’) and individual retailer risk-management decisions.

This chapter focuses on competition and the costs to retailers of supplying electricity in the National Electricity Market (NEM) in 2022–23.

To inform this chapter, the ACCC issued compulsory information gathering notices, extending our dataset of costs incurred by retailers to supply electricity to households and businesses across the NEM out to 30 June 2023. These costs include wholesale electricity costs, network costs, environmental costs, retail costs and retail margins. The chapter:

- explains the impacts of energy market volatility from mid–2022 on retailers' costs
- analyses changes in market structure metrics, with a focus on change over 2022–23
- explains how price regulation is currently operating in retail electricity markets

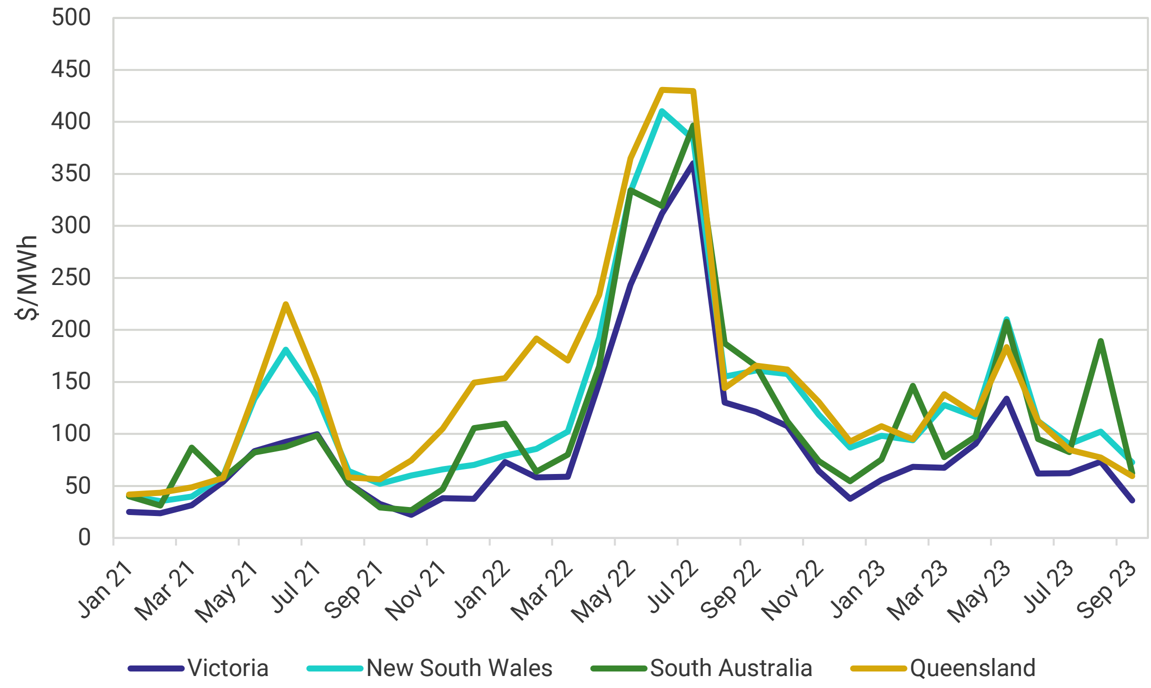
- analyses aggregated retailer costs to show the costs that underlie electricity bills
- provides insight into changes in retail margins in 2022–23 and over the longer term.

2.1. Events in mid-2022 continue to affect retailers

In mid-2022, conditions in international and domestic energy markets drove wholesale electricity prices to historic levels and led to challenges in operating the NEM. This resulted in the first whole-of-market suspension in the history of the NEM in June 2022. Figure 2.1 reveals the significant spot market price spikes that occurred in mid-2022, whilst Figure 2.2 reveals the substantial increases in contract prices over the course of 2022.

Figure 2.1 Spot prices rose substantially in all regions in mid-2022

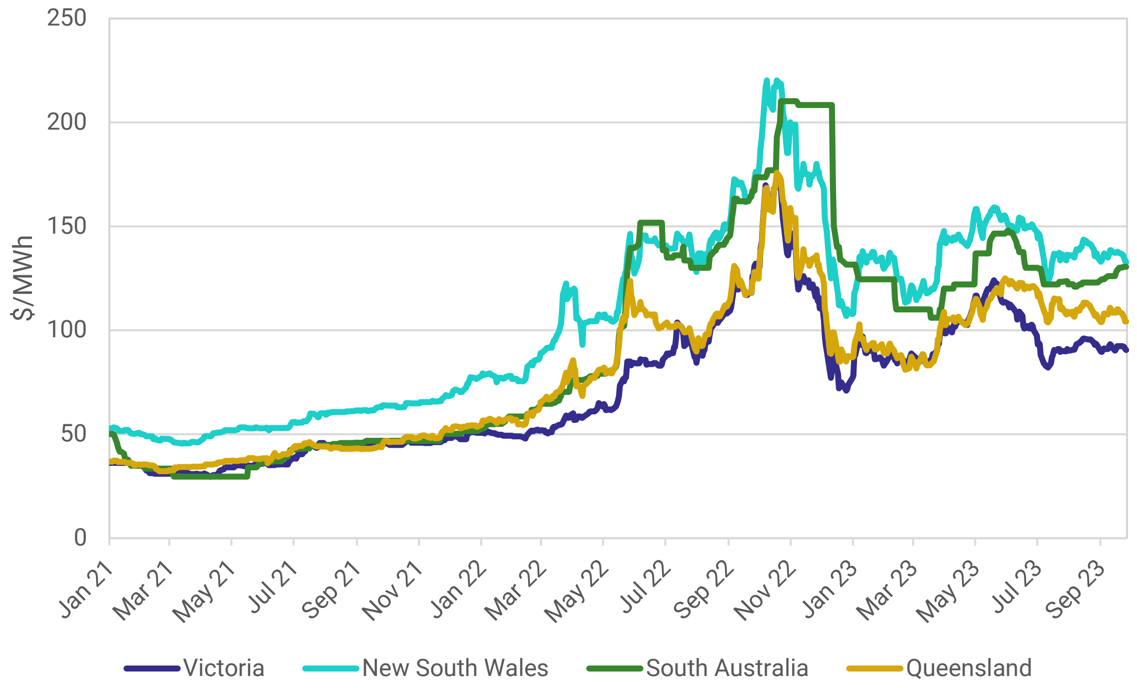
National Electricity Market volume weighted spot price by region, monthly, January 2021 to September 2023



Source: Australian Energy Market Operator.

Figure 2.2 The increase in contract prices were delayed compared to spot prices, rising in late-2022 and remaining somewhat elevated

Daily base futures contract settlement price by region, quarter 2 2024, 1 January 2021 to 18 October 2023



Source: ASX Energy Data Centre

Although market conditions have eased since mid-2022, the market volatility from this period continues to affect retailers as prices in both the spot market and hedging contract markets determine the wholesale costs that flow through to customer bills. Changes in these markets often take time, sometimes years, to flow through to customer bills. This is due to retailers managing the risk of volatile wholesale spot prices through 'hedging' strategies.

Hedging involves generators and retailers entering into contracts where they agree on a set price for the sale and purchase of electricity in a future period. This provides more certainty to these businesses regarding the price they will purchase or sell their electricity at, reducing their financial risk. Hedging contract prices indicate market expectations of future spot prices.

Hedging is necessary because wholesale spot prices are volatile, with prices that vary every 5 minutes. As prices reflect supply and demand in real-time, spot prices can vary dramatically. Wholesale prices in the NEM can vary between negative $1,000 per megawatt hour and $16,600 per megawatt hour. By hedging, retailers serve as an interface between the volatile prices in the wholesale market and the more stable prices wanted by consumers.

Retailer hedging strategies vary, with some retailers using hedging contracts to cover all of their electricity purchase requirements, while others purchase a greater proportion of their customers' electricity from the spot market. When 'fully hedged' (that is, their entire retail load is subject to hedging contracts rather than being purchased on the spot market)[11], a retailer's wholesale cost of purchasing electricity for its customers will reflect their hedging contracts, rather than the wholesale spot price. Additionally, retailers that are vertically integrated (that is, that also own generation or storage assets) can be considered to have a 'natural hedge' as changes in wholesale prices that increase retail costs will be offset by increasing generator revenues.

There is variation in the time periods that retailers hedge for, though most retailers build a 'hedge book' to cover their forecast demand 1 to 3 years ahead of the current period. For fully hedged retailers, their wholesale costs will only vary when they renegotiate or sign new hedging contracts upon the expiry of their existing contracts. We discuss retailer hedging strategies in further detail in Chapter 4.

As a result, there can be substantial lags between when changes in spot and contract prices flow through to retailers' wholesale costs. There are also likely to be lags between when changes to wholesale costs flow through to retail prices and consumer bills, as retailers may not immediately update their prices and electricity billing is generally done in arrears.

2.2. Retail market concentration remained stable over 2022–23

The NEM covers all states and territories in Australia, except Western Australia and the Northern Territory. However, competitive retail markets for residential and small business customers have only developed relatively recently in New South Wales, Victoria, South East Queensland, and South Australia, having been progressively introduced since the early to mid-2000s. Full retail competition in these regions opened the retail market to private retailers to compete for customers. Over time, in some markets, regulated prices were also removed (Figure 2.8).

However, the majority of retail electricity customers in regional Queensland, Tasmania and the ACT continue to pay regulated standing offer prices and are served by an incumbent, government-owned retailer (see section 2.4).[12]

Measures of market concentration are used in assessing how competitive a market is. One commonly used market concentration metric is the Herfindahl-Hirschman Index (HHI). The HHI is calculated by summing the squares of the market share of all firms competing in a market. By squaring market shares, the HHI highlights the impact of large firms on the market and the disparity in size between firms. The higher the HHI, the more concentrated the market is. A decrease over time indicates a decrease in market concentration, which may indicate a more competitive market.

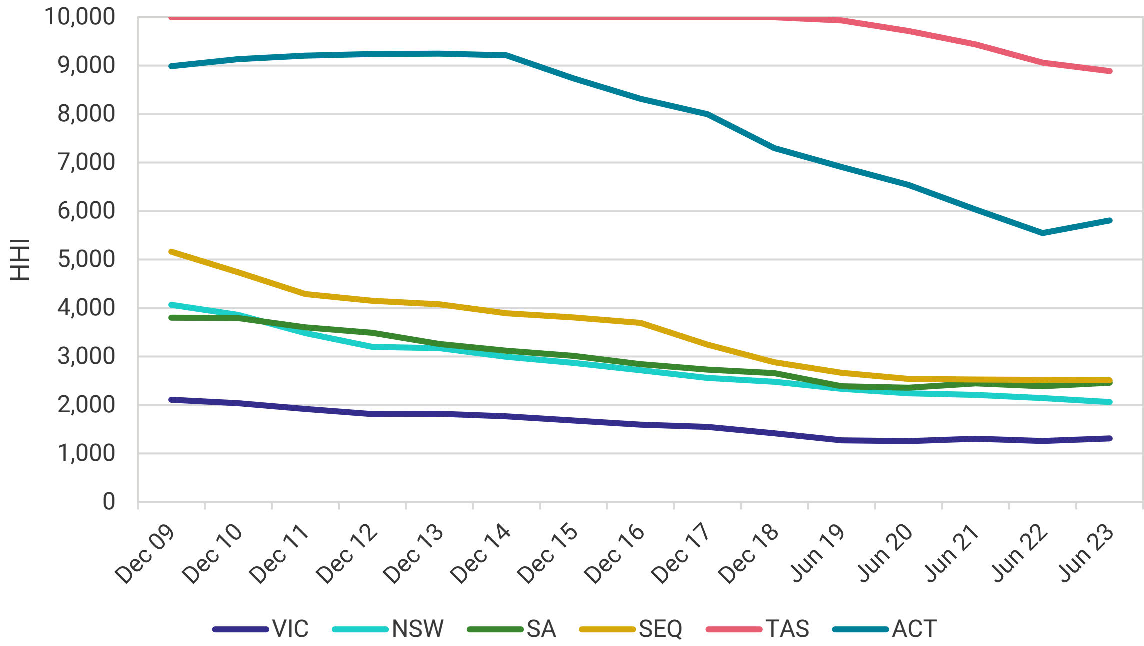
Figure 2.3 presents the HHI for each region in the NEM, where 0 indicates a state of perfect competition and 10,000 indicates a monopoly market.

11 Retailers can also be 'over hedged', in which case they would have contracts in place to purchase a greater volume of electricity than their retail load. In this circumstance, retailers would have the ability to on-sell the excess electricity.

12 Ergon Energy in regional Queensland, Aurora Energy in Tasmania, and ActewAGL in the ACT.

Figure 2.3 Market concentration has declined since 2009 and remained stable over 2022–23

Herfindahl-Hirschman Index by region, December 2009 – June 2023



Source: Australian Energy Market Commission, Figure 3.3a: Long-term changes in HHI, 2009 to 2018 (electricity), AEMC website; Australian Energy Regulator, Retail energy market performance update for Quarter 4, 2022–23 [data set], AER website; Essential Services Commission of Victoria, Energy market dashboard [data set], ESC website.

There is no official guidance on what constitutes a 'concentrated' market using the HHI. One benchmark is the United States Department of Justice and Federal Trade Commission's 2010 Horizontal Merger Guidelines,[13] which classifies markets into 3 types based on the index:

- unconcentrated markets have a HHI below 1,500
- moderately concentrated markets have a HHI between 1,500 and 2,500
- highly concentrated markets have a HHI above 2,500.[14]

As shown in Figure 2.3, HHI has declined since 2009 across the NEM, as more retailers have progressively entered the market. However, there is significant variation between regions. Using the scale above for June 2023, Victoria would be classified as an unconcentrated market, whilst New South Wales, South Australia, and South East Queensland would be moderately concentrated, and the ACT and Tasmania would be highly concentrated markets.

The HHI is significantly lower in New South Wales, Victoria, South East Queensland, and South Australia compared to Tasmania and the Australian Capital Territory (ACT). Victoria's lower market concentration and slower rate of change can be attributed to its early move to competitive retail markets and removal of price controls. Conversely, South East Queensland's higher market concentration and quicker rate of change can be attributed to

[13] In Australia, the ACCC's Merger Guidelines encourage merger parties to notify the ACCC if the merged firm will have a post-merger market share of more than 20%; and state that the ACCC is less likely to identify horizontal competition concerns if the post-merger HHI is less than 2,000, or, if it is more than 2,000, if the change in HHI is less than 100; See ACCC, 'Merger Guidelines', ACCC, Australian Government, 21 November 2008, accessed 10 October 2023.

[14] The United States Department of Justice and the Federal Trade Commission (FTC), 'Horizontal Merger Guidelines', FTC, 19 August 2010, accessed 10 October 2023.

its later removal of price regulation and the swift entry of established retailers from other markets.

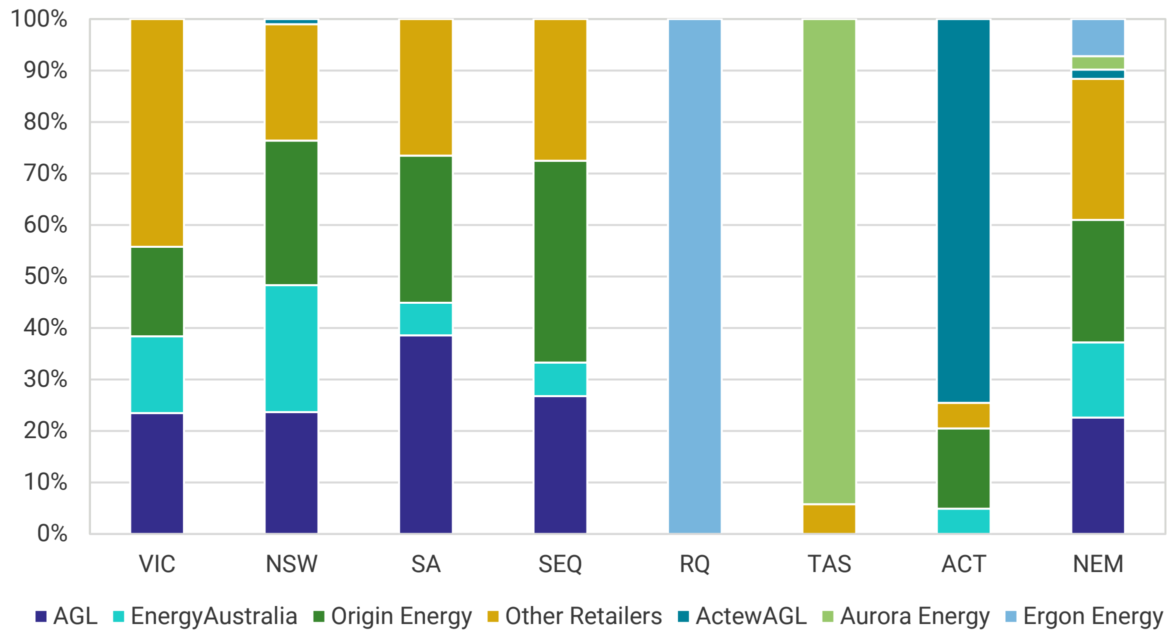
New South Wales, South Australia, and South East Queensland hover around the moderate to highly concentrated threshold, between 2,000 and 2,500. Victoria is the only market that could be considered unconcentrated based on the HHI.

As shown in Figure 2.3, the HHI remained relatively stable in all regions with full retail competition in recent years. In 2022–23, Victoria, South Australia, and the ACT recording a slight increase in market concentration, compared to slight declines in New South Wales, South East Queensland and Tasmania.

The majority of customers in New South Wales, Victoria, South East Queensland, and South Australia continue to be served by Origin Energy, AGL or EnergyAustralia (Figure 2.4). These 3 retailers, often termed the 'big 3', are typically grouped together as incumbent retailers, as they purchased the customer base in certain distribution regions at the time of deregulation, are vertically integrated, and continue to hold a large share of the market.

Figure 2.4 Most customers continue to be served by incumbent retailers

Retail electricity market share by region, 2022–23



Source: Australian Energy Regulator, Retail energy market performance update for Quarter 4, 2022–23 [data set], AER website; Essential Services Commission of Victoria, Energy market dashboard [data set], ESC website.

Note: NEM = National Electricity Market, NSW = New South Wales, VIC = Victoria, SEQ = South East Queensland, RQ = Regional Queensland, SA = South Australia, TAS = Tasmania, ACT = Australian Capital Territory.

The group of 'Other Retailers', which excludes the 6 retailers shown individually in Figure 2.4, serves approximately 27% of customers across the NEM. As reflected in the HHI, Victoria has the least concentrated market with 44% of small customers served by the group of 'Other Retailers', while South East Queensland and South Australia both have one retailer capturing more than 30% of the market (Origin and AGL, respectively).

Within this group, there are some retailers with significant market share in certain distribution regions. For instance, Alinta Energy has a larger share of the market in South East Queensland (14%) than EnergyAustralia, while retailers like Red Energy in

New South Wales, and Simply Energy in South Australia and Victoria, have captured close to 10% of the market.

These medium-sized retailers tend to be either vertically integrated (Alinta), or, alternatively, their parent company owns, or is a generation business (for example, Simply Energy, Red Energy and Momentum Energy).

2.3. Several electricity retailers exited the market in 2022 and 2023

New entrants into a market can contribute to competitive outcomes through competing with existing retailers on price, product offering and innovation, and service quality. Retail competition in Australia has increased over the last decade as new entrants entered and diversified the market. The competitive threat new entrants pose can improve value for consumers and incentivise innovation, therefore highlighting the importance of ensuring that barriers to entry are low enough for new entrants to enter the market.

It is normal for businesses to exit in well-functioning markets due to various factors such as changing consumer demands or economic shifts. Businesses that operate based on higher risk strategies or whose innovations fail are prone to exiting the market at any time, particularly when disruptions occur. However, numerous retailers exiting the market (or becoming inactive) may negatively impact competition, as the number of market participants declines.

Between 2016 and 2022, 5 retailers exited the market through the Retailer of Last Resort scheme.[15] There were 7 in 2022 and another 3 in 2023. This was due to wholesale electricity spot prices increasing dramatically and reaching unprecedented average levels in the second quarter of 2022. This led to the suspension of all regions of the NEM in June 2022.

Some retailers were more exposed to price and volume risk than others, and the market saw a number of retailers exit, either through a Retailer of Last Resort event or by surrendering their retailer authorisation.

Further, some unusual retailer behaviour was observed in mid-2022, as high wholesale electricity prices created unusual incentives for retailers to reduce market share and capitalise on the value of hedge contracts. We observed a small number of retailers strongly urge customers to change retailers or face significant price increases, with the effect that their market share decreased.[16]

Figure 2.5 shows the number of retailers entering the electricity retail market peaked in 2019, with entries exceeding exits between 2016 and 2021. This likely reflects that barriers to entry are low enough so as not to prevent new entrants to the market, a positive sign for competition in the market over this period. However, this trend reversed during the energy volatility events in mid-2022, which saw a significant number of electricity retailers exit the market through surrendering their authorisations or having their authorisations revoked. This trend has continued in 2023, with no new entrants and more retailers exiting the market.

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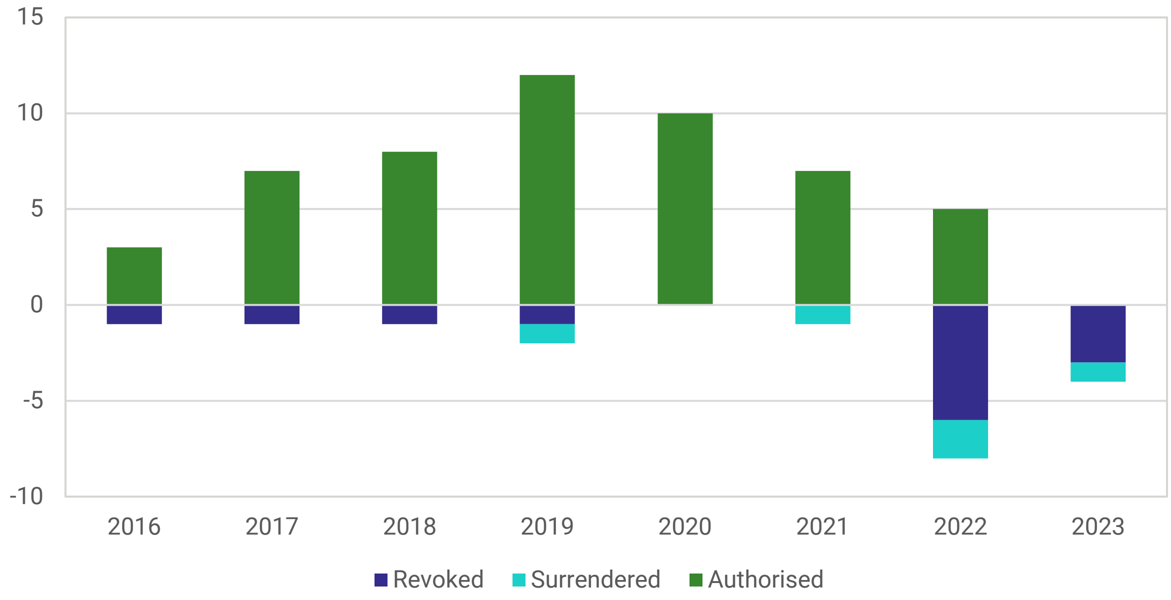
15 The retailer of last resort scheme is designed to ensure that, in the event of a retailer failing, customers continue to receive electricity (or gas) supply. When a retailer fails, the AER ensures their customers are transferred to the relevant retailer of last resort for that distribution zone (generally one of the big 3 retailers). While the underlying causes of the failure may vary, a retailer will generally enter the retailer of last resort scheme when it can no longer supply its customers.

16 ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 87.

Figure 2.5 The number of retailers entering the market peaked in 2019

Retailer exits (surrender or revocation of retailer authorisation) and retailer entry (grant of authorisation) by year, National Electricity Market (excl. Victoria)



Source: ACCC analysis of Australian Energy Regulator, Public register of authorised retailers & authorisation applications, AER website, n.d., accessed 20 September 2023.

Note: Surrenders of retail licences can occur for a variety of reasons, and do not necessarily indicate an active retailer has left the market. For example, of the 4 retail surrenders between July 2022 and March 2023, 3 had no or very few customers prior to surrender and one transferred its customer base to its parent company.

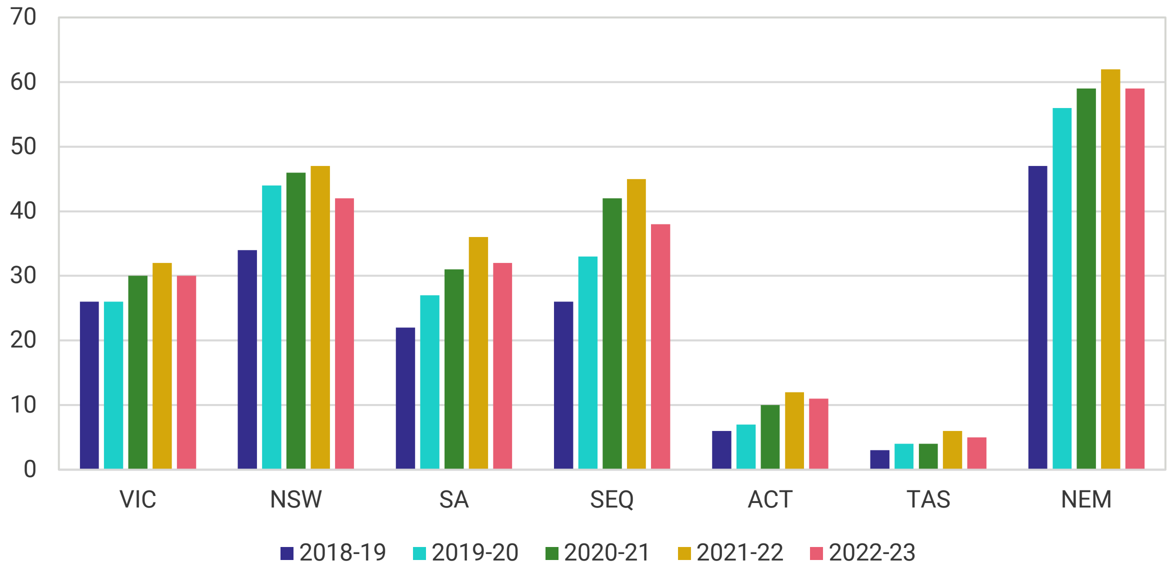
The Australian Energy Regulator last granted a retail authorisation in June 2022[17], with the same entrant granted an electricity retail licence from the Essential Services Commission of Victoria in April 2023. There are currently 2 open applications for retail authorisation with the Australian Energy Regulator.[18] The lack of new entries combined with retailer exit has resulted in a small decline in the number of active retailers in all regions, in a reversal of a years-long trend towards increasing numbers of active retailers, as shown in Figure 2.6.

17 AER, Ampol Energy (Retail) Pty Ltd – authorised electricity retailer, AER, Australian Government, 8 June 2022, accessed 19 October 2022.

18 AER, Tas Gas Retail Pty Ltd – Application for electricity retailer authorisation – Request for submissions, AER, Australian Government, 16 November 2023, accessed 19 October 2023.

Figure 2.6 The number of active retailers in the market has declined since 2021, following years of steady increases due to market volatility

Number of active electricity retailers by year and region, 2018–2023



Source: ACCC analysis of the AER's retail performance data; ESC, *Energy market dashboard*, ESC website, n.d., accessed 31 October 2023; ESC, *Victorian Energy Market Report*, ESC website, n.d., accessed 31 October 2023.

Note: The number of active Victorian electricity retailers from 2018–2020 were attained from the retailer profiles section of previous Victorian energy market reports. The number of active Victorian electricity retailers from 2021–2023 were attained from the energy market dashboard. An active retailer is defined as a retailer with more than 50 customers.

2.4. Customer switching spiked in recent months

Another metric to measure the competitive dynamic in the electricity retail market is customer switching rates, often termed the 'churn rate'. The churn rate indicates how many customers are willing to switch electricity retailers in response to better products becoming available, an increase in price, or a decline in service.

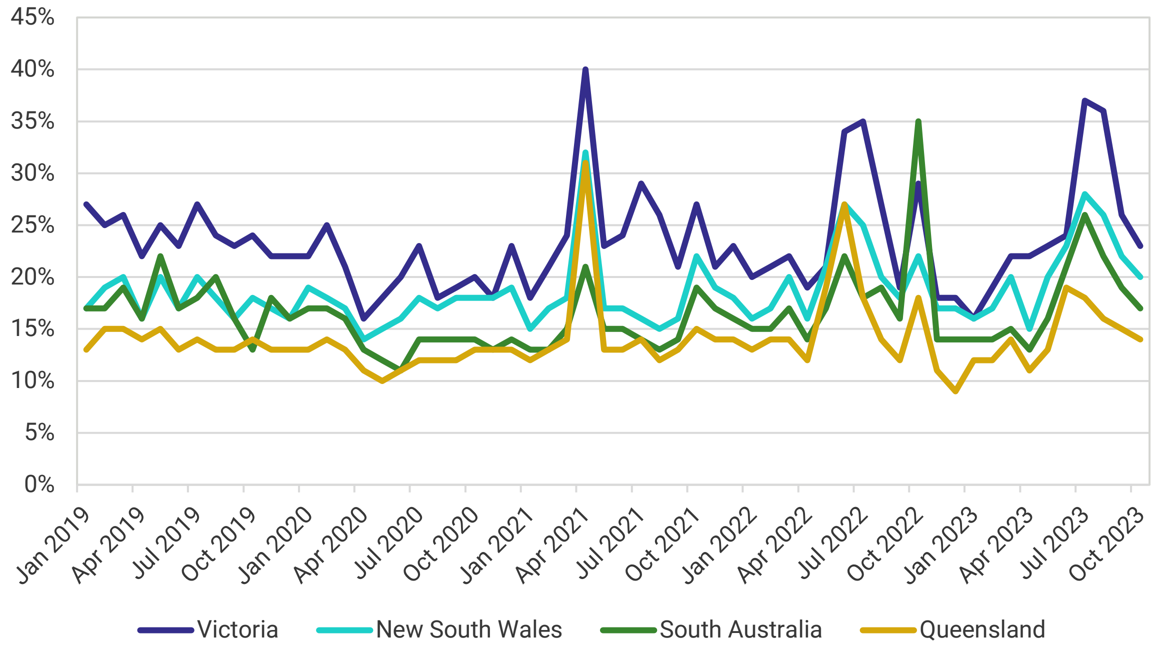
One source of data on customer switching is the Australian Energy Market Operator's monthly retail transfer statistics. The statistics are based on the number of consumer transfers registered in their market system – Market Settlement and Transfer Solutions – where a consumer transfer occurs when a meter is changed to a different retailer.

Presented in Figure 2.7, this data indicates that switching has generally remained relatively static since the start of 2019, aside from sharp increases reported in:

- April 2021: when Click Energy customers transferred to AGL
- April–October 2022: likely in response to the energy volatility events in mid–2022
- July–August 2023: likely in response to significant price increases and widespread media reporting.

Figure 2.7 The proportion of consumers switching has remained static except for sharp increases in response to market events

Historical one-month annualised transfer rate, January 2019 – October 2023



Source: Australian Energy Market Operator, Retail Transfer Statistical Data.

In isolation, this recent spike in customer switching is a positive sign for competition, however, the retail transfer data does not capture the full extent of customer switching. For example, a customer who transfers to a new plan but remains with the same retailer is not captured.

When consumers are asked about their engagement, like in the June 2023 Energy Consumers Australia sentiment survey, only 7% of households said they changed energy companies in the past year, while another 7% switched energy plans with their current provider. This is considerably lower than the churn rate reported across the market by the Australian Energy Market Operator.

2.5. Retail competition co-exists with price regulation and other government interventions

2.5.1. Price caps on standing offers

To protect consumers, the introduction of full retail competition (see section 2.2) was accompanied by a statutory mechanism to set the price for electricity sold under a standard retail contract (a standing offer).

Under the Australian Energy Market Agreement in 2004, federal, state, and territory governments agreed to phase out retail price regulation where effective retail competition could be demonstrated.[19] However, they also agreed that, where competition is not yet effective for a market, group of users or a region, or where effective competition for categories of users ceases, retail price controls can be imposed.[20]

Accordingly, standing offer prices were progressively deregulated in Victoria, New South Wales, South East Queensland, and South Australia, as more customers moved to market retail contracts, while standing offer prices remained regulated in regional Queensland, Tasmania, and the ACT under jurisdiction-specific applications of the *National Energy Retail Law*[21] (Figure 2.8).

Box 2.1 What is a standing offer?

Under the National Energy Retail Law and Victorian Energy Retail Code of Practice, there are 2 types of customer retail contracts:

- standard retail contracts with standing offer prices
- market retail contracts with market offer prices.

Standard retail contracts must contain prescribed terms and conditions, which require customers to be given a higher level of consumer protections than under a market retail contract.

In 2019, standing offer prices were re-regulated in Victoria, New South Wales, South East Queensland, and South Australia. In Victoria this was achieved through the introduction of the Victorian Default Offer[22], while in New South Wales, South Australia and South East Queensland, some standing offer prices were capped by the Australian Government through the introduction of the Default Market Offer (see section 3.1).[23] The Default Market Offer applies to 9.0% of residential customers and 17.9% of small business customers.[24] The Victorian Default Offer applies to 13.7% of residential customers and 19.9% of small business customers.[25]

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19 Department of Climate Change, Energy, the Environment and Water (DCCEEW), Australian Energy Market Agreement (as amended), DCCEEW, Australian Government, 9 December 2013 (entered into force 30 June 2004), cl 14.11.

20 DCCEEW, Australian Energy Market Agreement (as amended), cl 14.15 – 14.16.

21 See *National Energy Retail Law (Queensland)* (Qld) s 22A; *National Energy Retail Law (Tasmania) Act 2012* (Tas) s 18; *National Energy Retail Law (ACT) Act 2012* (ACT) s 14.

22 See Minister for Energy, Environment and Climate Change, 'Order under section 13 of the *Electricity Industry Act* 2000' in Victoria, *Victoria Government Gazette,* No S 208, 30 May 2019.

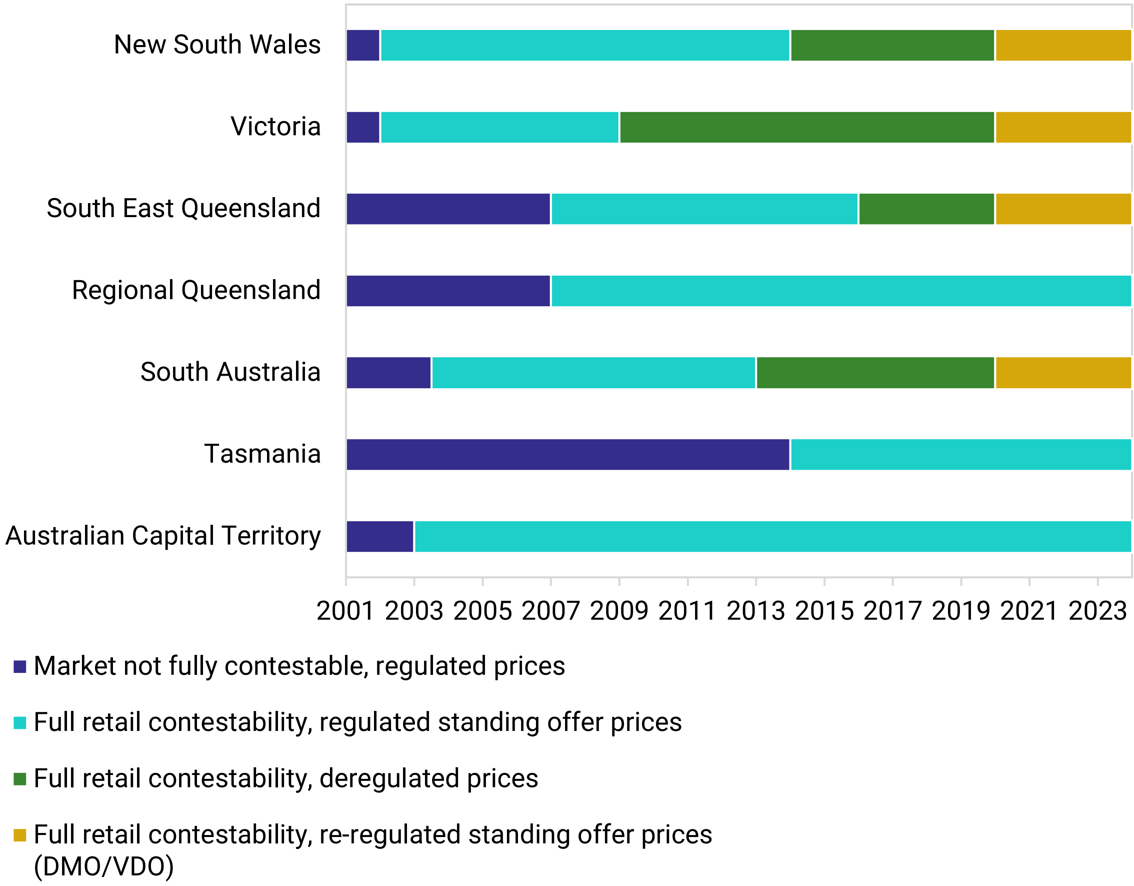
23 See Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (Cth) s 10.

24 AER, Retail Market Performance Data Schedule 2 [data set], accessed 16 November 2023.

25 Essential Services Commission of Victoria (ESC), Energy Market Dashboard [data set], Essential Services Commission of Victoria website, n.d., access 16 November 2023.

Figure 2.8 Full price deregulation was a short-term proposition

Timeline of deregulation and retail contestability by region



Under the Energy Retail Code of Practice in Victoria and the Electricity Retail Code in New South Wales, South Australia and South East Queensland, retailers are required to advertise their electricity prices with reference to the Victorian Default Offer and Default Market Offer, respectively.

As a mandatory industry code under Part IVB of the Competition and Consumer Act, the ACCC is responsible for monitoring and enforcing compliance with the Electricity Retail Code.

In June 2023, CovaU and ReAmped Energy each paid $33,300 in penalties after the ACCC issued each retailer with 3 infringement notices for alleged contraventions of the Electricity Retail Code. It was alleged that, when sending information to customers about changes to their electricity prices in 2022, CovaU and ReAmped Energy each failed to include required information to help consumers compare electricity plans.[26]

On 22 September 2023, the ACCC instituted proceedings against EnergyAustralia, alleging contraventions of the Code and the Australian Consumer Law. This is the first time the ACCC has commenced litigation in relation to an alleged breach of the Electricity Retail Code.[27]

26 ACCC, CovaU and ReAmped pay penalties for alleged breaches of electricity code [media release], ACCC, Australian Government, 27 June 2023, accessed 27 November 2023.

27 ACCC, EnergyAustralia in court over alleged misleading electricity price information [media release], ACCC, Australian Government, 22 September 2023, accessed 27 November 2023.

2.5.2. The Competition and Consumer Act imposes specific obligations on electricity companies

Further intervention in the retail electricity market occurs under Part XICA of the Competition and Consumer Act. Part XICA sets out 3 kinds of prohibited conduct, being in relation to retail prices, the electricity financial contract market, and the wholesale electricity market.

The retail pricing prohibition requires electricity retailers to make reasonable adjustments to the prices of their offers to reflect sustained and substantial reductions in their underlying cost of procuring electricity.

Part XICA commenced on 10 June 2020 and is currently due to sunset on 1 January 2026[28], after the ACCC's inquiry into the NEM concludes. The Treasurer is required to establish a review of the effectiveness of the provisions within 4 years of their commencement, which will examine their impact on electricity market performance, including market efficiency, equity, reliability, affordability, emission reduction and investment outcomes.[29]

2.6. Retailers' costs and profitability increased in most regions in 2022–23

In this section, we analyse retailer costs to show the aggregated costs that underlie customers' electricity bills. This provides insights into the drivers of retail electricity price changes.

We do this by building a 'cost stack' of the different cost components that retailers incur to supply electricity to their customers. Doing so allows us to calculate a retail margin, which is the amount left after the retailer has accounted for all other components of its cost stack. The higher the margin, the more profitable a retailer is.

We average our cost stack results across retailers to produce an average annual cost to supply electricity per customer. We also calculate a cost per unit of electricity usage (measured in cents per kilowatt hour) by dividing retailer costs by usage (termed the 'effective price').[30] Both measures are based on the costs faced by retailers for supplying electricity to customers. We also measure retail margin using earnings before interest, tax, depreciation, and amortisation (EBITDA), which reflects what a retailer earns after accounting for its costs.

We have collected retailer cost stack information up to 30 June 2023, capturing the financial implications for retailers of the June 2022 events in the NEM up to this time, and supporting comparison of retailer costs and margins over time since 2007–08.

Box 2.2 summarises the retail costs underlying the supply of electricity to customers and provides further explanation of retail margins.

28 *Competition and Consumer Act 2010* (Cth) s 153B.

29 *Treasury Laws Amendment (Prohibiting Energy Market Misconduct) Act 2019* (Cth) sch 1 pt 4.

30 Noting that usage differences can vary dramatically within residential samples, and for small business customers, which have a much larger range of electricity usage than residential customers.

Box 2.2 What are the components of a retailer's cost stack?

A retailer's total cost stack comprises a number of components:

- network costs charged by network operators for the transmission and distribution of electricity (for the use of the 'poles and wires' to transport electricity) and metering
- wholesale costs of purchasing electricity from the wholesale spot market (or costs of generation for vertically integrated retailers owning generation assets), and of managing price exposure
- costs of complying with environmental (green) schemes, both state and national
- costs of running a retail business, such as billing, customer service, or marketing costs.

A retail margin is what a retailer earns after accounting for the above costs, reflecting the return to the retailer's investors.

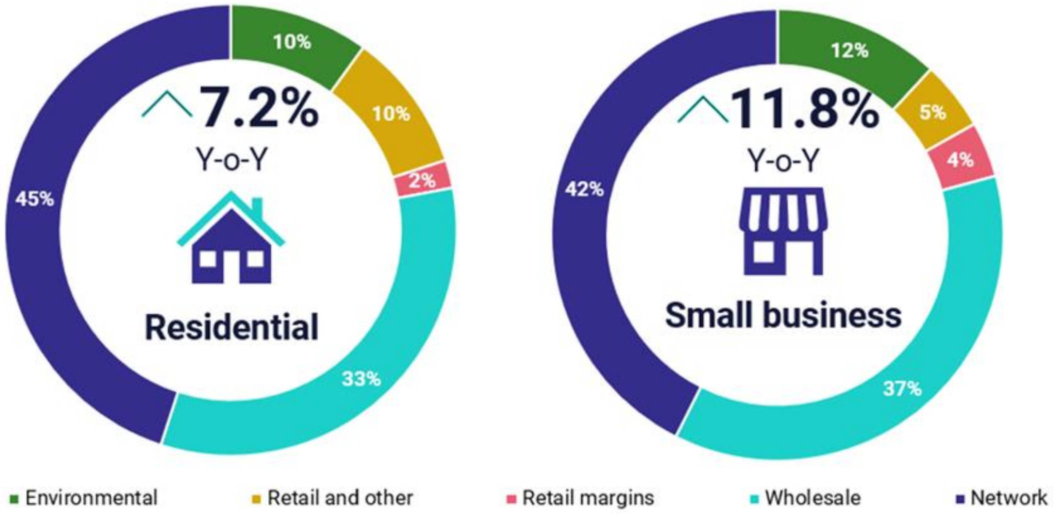
The retail margin is measured as earnings before interest, tax, depreciation, and amortisation (EBITDA). The EBITDA margin reflects a level of return for the risks faced by retailers in the market. A retailer's EBITDA does not include the retailer's earnings from other parts of the supply chain, such as electricity generation.

2.6.1. Rising wholesale costs drove increased costs for retailers in 2022–23

As in previous years, network and wholesale costs combined to form the major proportion of annual costs to retailers for supplying both residential and small business customers (Figure 2.9). Wholesale costs grew as a proportion of the average annual cost of supplying electricity to a residential customer in the NEM, from 28% in 2021–22 to 33% in 2022–23.

Figure 2.9 Retailer cost stacks increased in 2022–23

Cost components for the average residential and small business customer in the National Electricity Market, 2022–23, nominal, excluding GST



Source: ACCC analysis of retailers' data.

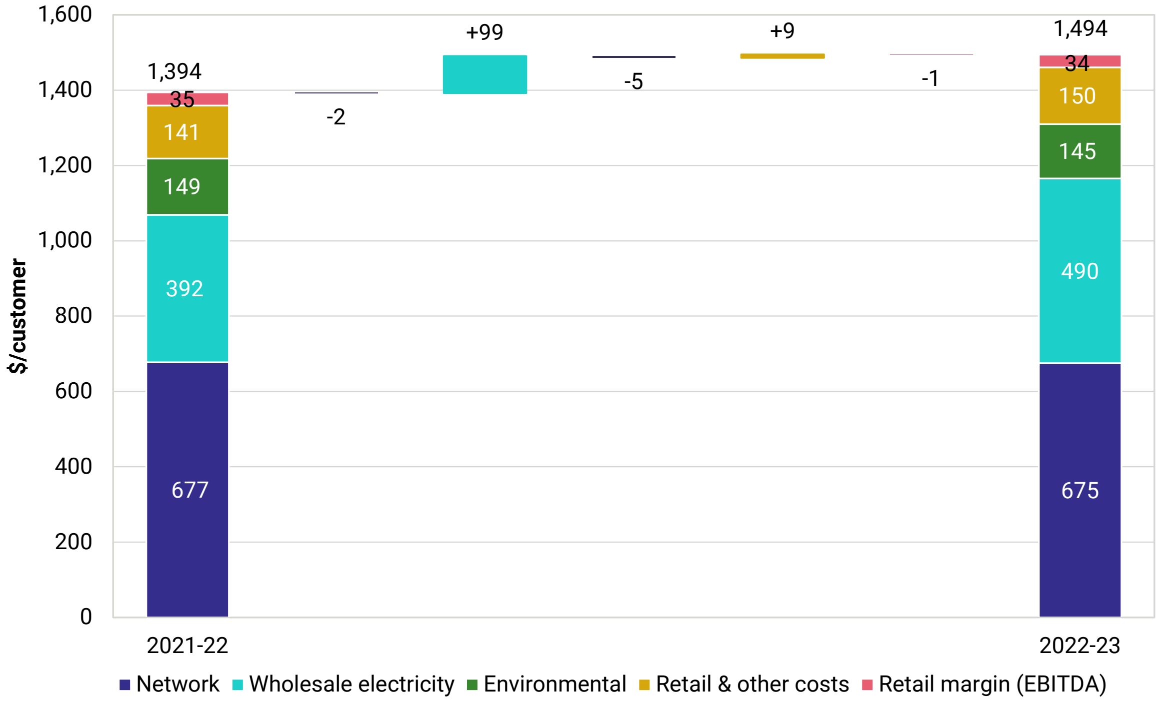
Note: Year on year percentage change is in nominal dollars.

The average total cost stack for retailers supplying residential customers in the NEM increased by 7.2% in nominal terms from 2021–22 to 2022–23 (1.1% in real terms) (see Figure 2.10). This increase was attributable to a 25% increase in wholesale electricity costs per customer (18% in real terms), with all other cost components remaining relatively stable.

Meanwhile, the average total cost stack for retailers supplying small business customers in the NEM increased 11.8% in nominal terms (5.4% in real terms). Similar to the supply of electricity to residential customers, this was driven by an increase of 28% (nominal) in wholesale electricity costs per customer (20% in real terms). While network costs and retail margins also increased for small business customers, a small reduction in environmental costs per customer offset these increases.

Figure 2.10 Retailer wholesale costs for residential customers increased in 2022–23

Change in retailer cost components for supplying the average residential customer across the National Electricity Market, 2021–22 to 2022–23, nominal, excluding GST

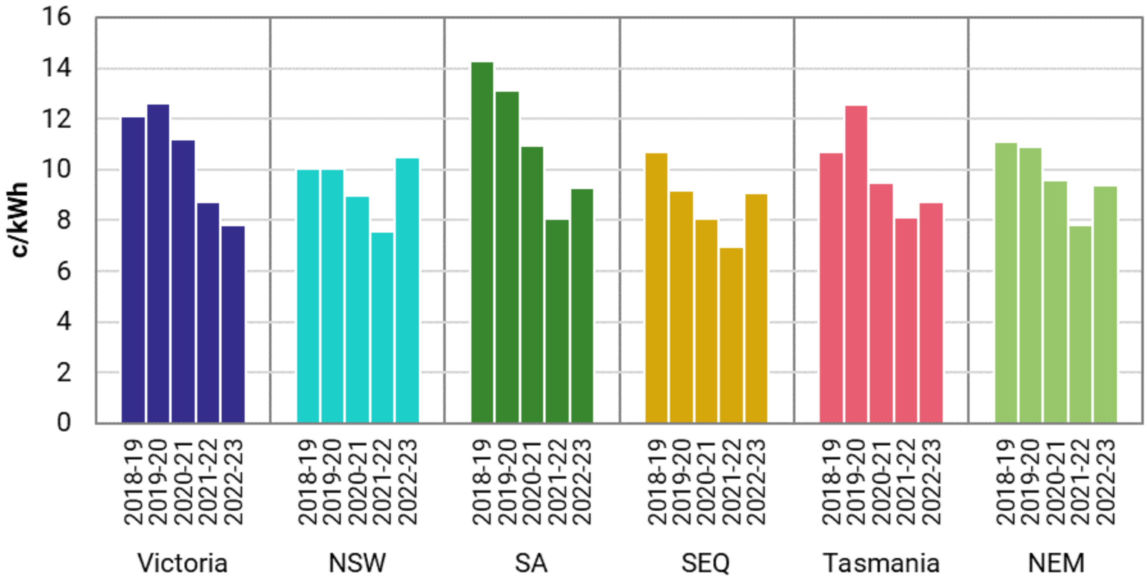


Source: ACCC analysis of retailers' data.

Figure 2.11 illustrates that wholesale costs (measured in effective price, or cents per kilowatt hour) increased for all regions except Victoria. Prior to 2022–23, the general trend was toward wholesale costs reducing over time. Nevertheless, wholesale costs in 2022–23 remained lower than in 2018–19, in real terms, in all regions except New South Wales. This reflects the relatively long period of declining electricity spot and wholesale contract prices prior to 2022–23.

Figure 2.11 Retailer wholesale costs increased in most regions in 2022–23

Average retailer wholesale costs (measured in effective price) for residential customers by National Electricity Market regions, 2018–19 to 2022–23, real, excluding GST



Source: ACCC analysis of retailers' data.

Wholesale costs for residential customers (measured in effective price) in New South Wales in 2022–23 were above those in 2018–19, and higher than in all other regions. The increase in effective prices in New South Wales was largely driven by increases in the costs incurred pursuant to a transfer price, likely reflecting increased generation costs stemming from higher priced generation fuels in 2022–23.

New South Wales and Queensland electricity generation costs were pushed up by rising prices for black coal, which supplied about 60% and 67% of those regions' electricity generation in 2022–23, respectively.[31] In mid-2022, international prices for black coal reached around $700 per tonne from under $100 per tonne in 2020.[32] South Australian wholesale prices also rose due to a greater reliance on gas generation in 2022–23, which was also subject to substantial fuel price increases.[33] Our November 2022 report outlines a number of factors that contributed to these price rises, which included international geopolitical factors, domestic generator outages, weather conditions and logistics issues for the supply of coal.[34]

Accordingly, in December 2022, the Australian and state governments intervened to cap the price of black coal at $125 per tonne and gas at $12 per petajoule.[35] The Australian Energy Regulator noted the coal price cap resulted in some coal generators offering cheaper electricity into the wholesale market.[36] While it is likely that this had an effect in constraining wholesale costs, the ACCC heard that the effect of coal price caps on wholesale costs was

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31 Australian Energy Market Operator (AEMO), Australian PV Institute, Bureau of Meteorology, OpenNEM - Energy - NEM, OpenNEM website, AEMO, Australian Government 2023, accessed 8 November 2023.

32 AER, State of the energy market 2023, AER, Australian Government, 5 October 2023, accessed 24 November 2023, p 43.

33 AER, State of the energy market 2023, p 42.

34 ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 16.

35 Queensland also has a mechanism in place to achieve similar outcomes, though the directions to Queensland coal companies are not public; AER, State of the Energy Market 2023, accessed 23 November 2023, p 41.

36 AER, State of the Energy Market 2023, p 29.

not immediately reflected in retailers' generation costs due to the higher cost of coal already in the stockpile being accounted for, and so the impacts on 2022–23 data may be relatively limited.

Rises in spot and hedging contract prices in the first half of 2022 (and beyond) also contributed to increasing wholesale costs for retailers in 2022–23. While government interventions to cap coal and gas prices resulted in drops in hedging contract prices in December 2022 (Figure 2.2), many retailers likely already had hedging contracts in place for 2022–23 by the time the interventions were implemented.

Declining wholesale costs for small customers in Victoria were caused by a mix of factors

Wholesale costs for residential customers in Victoria declined, which contrasted with other regions. As noted above, spot and hedging contract prices rose in all regions, though Figure 2.2 reveals hedging contract prices in Victoria did not rise as high as in other regions (see Chapter 4 for further discussion of contract market outcomes).

Additionally, brown coal provides 58% of electricity generation in Victoria, and its price was generally insulated from the international fuel price spikes that contributed to the energy market volatility in mid–2022.[37] It appears that together, the availability of relatively low-cost generation from brown coal, and an increased proportion of renewables (36%), provided some insulation from pressures driving up wholesale costs in other regions, particularly for vertically integrated retailers.[38] In particular, as a group, the big 3 retailers reported substantial combined reductions in wholesale costs for residential customers in Victoria, which contributed to the results depicted in Figure 2.11.

While we note there are differences in methodology between calculation of the wholesale component of the Victorian Default Offer (a forecast based on hedging contract prices from the previous 12 months) and ACCC cost stack figures (historical costs reported by retailers, many of which are vertically integrated), the Essential Services Commission of Victoria noted in its 2023–24 price determination:

> [T]here are some retailers in Victoria that are vertically integrated and currently enjoy temporary cost advantages. This includes those that generate electricity using brown coal for which the prices are not tied to the international market. Retailers with established renewable generation assets such as wind and solar farms have also not had to face increases in fuel costs.[39]

Several retailers reported that their reduced wholesale costs for residential customers in Victoria were caused by having a greater volume of hedge contracts than needed for their retail load in 2022–23. These retailers reported that they were able to sell the extra contracts at particularly high prices, which offset their wholesale costs in that region, reducing the region's wholesale costs in Figure 2.11.

The regulatory transition in Victoria, which did not occur in other regions, may also have contributed to regional differences in year-on-year comparisons of wholesale costs between 2021–22 and 2022–23.

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37 AEMO, OpenNEM - Energy - NEM, OpenNEM website.

38 AEMO, OpenNEM - Energy - NEM, OpenNEM website.

39 ESC, *Victorian Default Offer 2023-24: Final Decision*, ESC, Victorian Government, 25 May 2023, accessed 23 November 2023, p 18.

While the Australian Energy Regulator sets the Default Market Offer price in New South Wales, South Australia and South East Queensland, the Essential Services Commission of Victoria sets the Victorian Default Offer. The Essential Services Commission moved the determination period for the Victorian Default Offer price from a calendar year basis to a financial year basis. This involved resets to the wholesale cost component of the Victorian Default Offer taking effect 3 times over the period January 2021 to July 2022 (inclusive).[40]

Several retailers noted that the change to the period of the regulatory determination referred to above influenced when they set their internal measure of wholesale costs, which in turn impacted that measure. This fed into their reported data for the relevant time periods. One such retailer's methodology for reporting wholesale costs to the ACCC does not apportion all of the outcomes of its hedging contract trading to its retail arm.

Vertically integrated retailers' internal measures of wholesale costs are often represented by a transfer price. Internal transfer pricing is the accounting practice of pricing transactions within businesses or between related parties, such as vertically integrated energy companies that have both generation and retail arms. A transfer price theoretically represents the price paid by a retail business to its generation arm for the supply of wholesale electricity. Although, it important to note that a transfer price may not represent a retailer's actual incurred costs. While variation exists between the transfer price methodologies applied by retailers that supply cost data to the ACCC, this does not diminish the utility of analysis of aggregated results presented in this and previous year's results.

Finally, a methodological change in the reporting from one retailer impacted the allocation of data between residential and small business customers, which impacted Victorian wholesale cost results. This had a small contribution to reducing wholesale costs for residential customers in Victoria (and other regions) and increasing wholesale costs for small business customers.

Nevertheless, we anticipate that wholesale costs will likely increase for Victorian residential customers in 2023–24, given the Essential Services Commission of Victoria increased the wholesale cost component in the Victorian Default Offer by 87% compared to its previous determination for 2022–23.[41]

2.6.2. Retail margin results were mixed across regions

Figure 2.12 shows that the average retail margin across the NEM declined in 2022–23 by $3 per residential customer (an 8% decline) in real terms. This is consistent with the general trend observed in retail margins of a decline from a peak of $154 per residential customer in 2016–17 to a new low in our timeseries of $34 per residential customer in 2022–23 (in real terms).

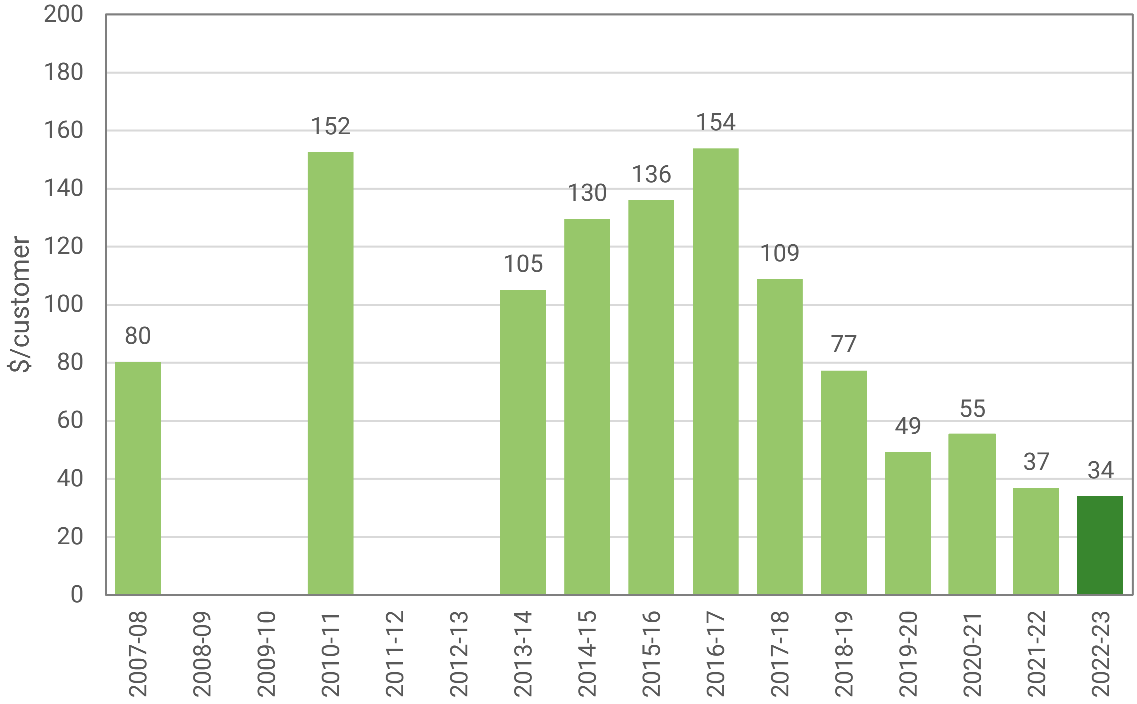
Over this timeframe, retail margins declined as a proportion of the total residential cost stack from 8.9% in 2016–17 to 2.3% in 2022–23. This substantial decline since 2016–17 was driven by declines in New South Wales and Victoria (Figure 2.12).

40 ESC, Victorian Default Offer Reviews, ESC website, n.d., accessed 23 November 2023.

41 ESC, *Victorian Default Offer 2023-24: Final Decision*, p 12.

Figure 2.12 National Electricity Market-wide retail margins in 2022–23 declined slightly to the lowest in our timeseries

Average retail margins (earnings before interest, tax, depreciation and amortisation) per residential customer across the NEM, 2007–08 to 2022–23, real, excluding GST[42]



Source: ACCC analysis of retailers' data.

Despite the small decline in retail margins for residential customers across the NEM in 2022–23, there was significant variation in changes in retail margins between regions. Margins increased in all regions except New South Wales (Figure 2.13). Negative margins in New South Wales brought down the NEM-wide results.

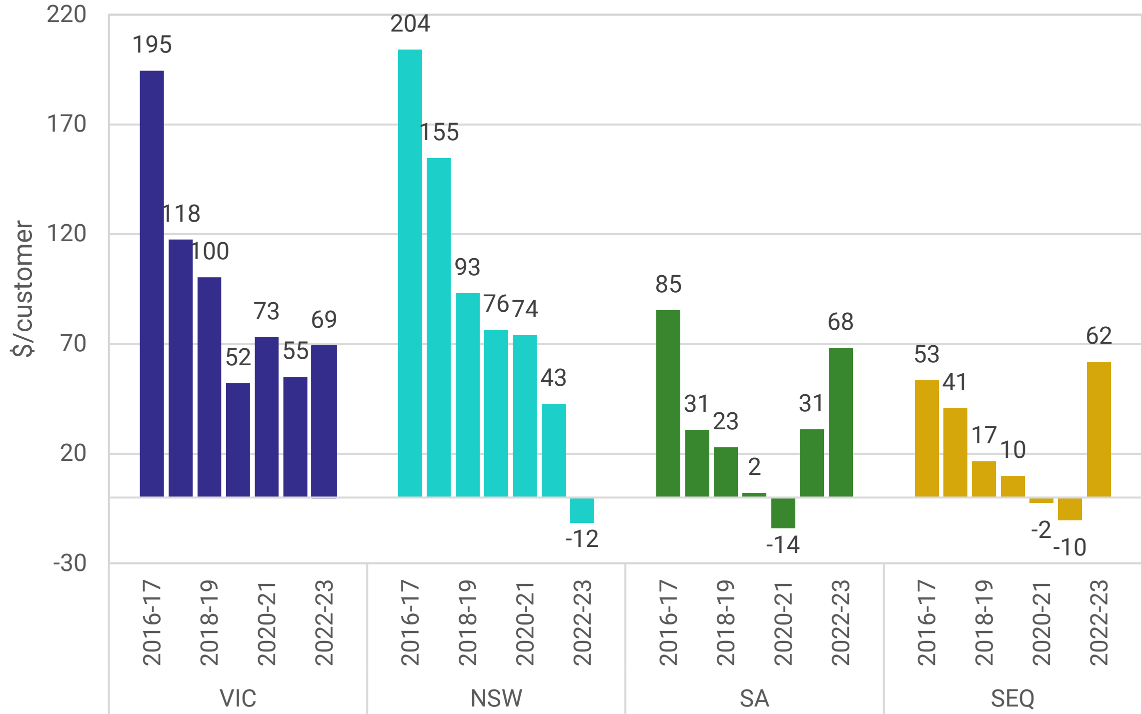
The retail margins for residential customers as a proportion of the total cost stack in each region in 2022–23 were:

- NEM: 2.3%
- New South Wales: -0.7%
- Victoria: 5.2%
- South Australia: 4.5%
- South East Queensland: 4.3%.

42 The Retail Electricity Pricing Inquiry only collected data for select years (2007–08 and 2010–11) prior to 2013–14 to reduce regulatory burden on retailers.

Figure 2.13 Retail margins for residential customers increased in all regions except New South Wales in 2022–23

Average retail margins (earnings before interest, tax, depreciation and amortisation) per residential customer, by region, 2016–17 to 2022–23, real, excluding GST



Source: ACCC analysis of retailers' data.

Information provided by the surveyed retailers indicates that aggregate revenues increased in New South Wales, South Australia, Queensland, and Victoria, for both residential and small business customers. Increasing revenues are to be expected as costs rise, as retailers increase prices to recover rising costs, resulting in increased revenues per residential and small business customer. Increased prices under the Default Market Offer and Victorian Default Offer also likely contributed to increased revenues. Where a retailer's revenues rise more than its costs, its margins will increase.

Both South Australia and South East Queensland saw substantial increases in retail margins per residential customer from 2021–22 to 2022–23, whilst Victoria recorded a somewhat smaller increase. The increased margins in South Australia and Queensland represent a substantial recovery after being negative in recent years. Retail margins in South Australia increased nearly to 2016–17 levels, while in South East Queensland, margins actually exceeded those in 2016–17.

The increases in the South Australian and South East Queensland margins occurred despite increasing wholesale costs in 2022–23. Different retailers each attributed varying reasons for this result. Some drivers of rising margins in these regions provided by some retailers included increased retail prices recovering higher costs associated with the current and prior period, better hedging performance, and increased customer numbers.

Meanwhile, New South Wales recorded a negative retail margin and a decrease that was significant enough to drive the NEM-wide decrease in Figure 2.12.

The retail margin result for residential customers in New South Wales was caused primarily by a substantial EBITDA loss by Origin Energy for this customer group. Origin Energy attributed this to higher coal costs increasing the cost of generation at the Eraring coal-fired power plant and hence, wholesale costs. Additionally, Origin Energy's reassessment of Eraring's useful life has resulted in accelerated depreciation of its asset, resulting in higher costs and lower retail margin. Our analysis revealed that, absent Origin Energy's New South Wales data, the average retail margin per residential customer would have increased substantially.

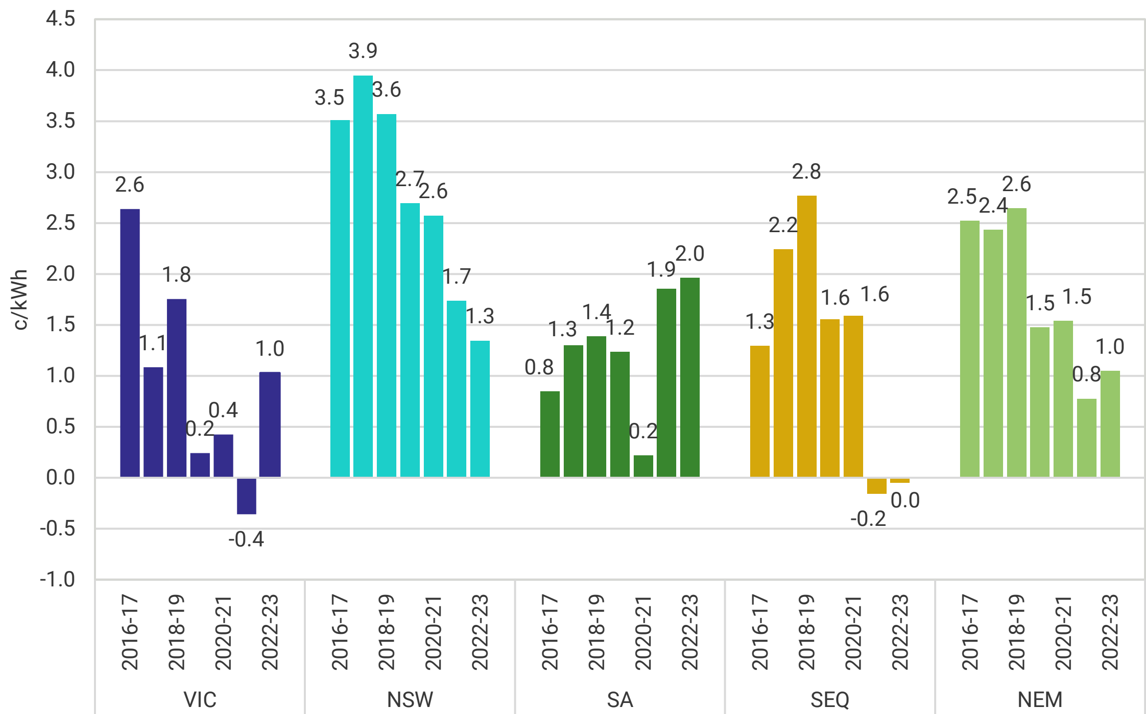
Retail margins for small business customers increased in 2022–23 from the record lows of 2021–22. Retail margins represent 3.9% of the average annual cost of supplying electricity to a small business customer in the NEM for 2022–23. Retail margins for small business customers increased in all regions except New South Wales.

However, as for residential customers, margins for small business customers have declined substantially in recent years. Particularly, retail margins dropped significantly from 2019–20, coinciding with the implementation of the Default Market Offer and Victorian Default Offer.

In 2022–23, margins remain substantially lower than in 2020–21. Consistent with outcomes for residential customers, declining small business margins were driven by New South Wales and Victoria, though South Australia has recorded generally increasing margins since 2016–17 (with the exception of 2020–21).

Figure 2.14 Retail margins for small business customers also increased in all regions except New South Wales in 2022–23

Average retail margins (earnings before interest, tax, depreciation and amortisation) for small business customers, c/kWh, by region, 2016–17 to 2022–23, real, excluding GST



Source: ACCC analysis of retailers' data.

The significant variance in retail margins between years, retailers, customer segments and regions highlight that the turmoil in electricity markets since the energy volatility events of mid-2022 has had varied effects on the market. It is crucial for the long-term health of the market that retail margins allow for an efficient retailer to earn a reasonable profit, whilst also ensuring that customers benefit through economically efficient pricing.

As noted in section 2.1, retailers play an important role in insulating consumers from spot price risk. Retail margins compensate retailers for taking on the risk of volatility in the market.

The ACCC has concerns that the risks associated with being an electricity retailer have increased in recent years. In part, the effects of the COVID-19 pandemic and rising costs of living appear to be impacting consumers' ability to pay their electricity bills.[43] This is resulting in increased bad debt costs, which rose by $9 per residential customer and $18 per small business customer in 2022–23 (in real terms).

In the context of stalled measures of market concentration and participation outlined in sections 2.2 and 2.3, the ACCC will continue to closely monitor how retail margins evolve and will consider implications for the competitiveness of the retail market.

Our analysis in Chapter 5 also reveals that challenging conditions in hedging contract markets have impacted retailers' ability to manage their spot price risk, particularly standalone retailers. It also finds that there are likely to be long-term challenges facing retailers that rely on the hedging contract market to manage their risk.

2.6.3. Retail costs stabilised in 2022–23 after years of decline

While we have observed declines in retail and other costs (which include costs to serve[44] and costs to acquire and retain customers[45]) over a similar period as for retail margins, these costs plateaued in 2022–23 (in real terms) (see Figure 2.15). Long term declines in retail and other costs support the view that retail competition has delivered benefits to consumers. It will be important to monitor how retail market performance and margins change as the retail market structure evolves.

As shown in Figures C8.6 and C8.8 in Appendix C, in aggregate, the big 3 retailers group continue to have significant cost advantages over the non-big 3 retailers group in both the costs to serve and costs to acquire and retain categories, indicating that the cost advantages for those retailers highlighted in the November 2022 report still exist.[46]

43 The number of hardship customers in New South Wales, South Australia, Queensland and Tasmania grew by 19% from quarter 3 2021–22 to quarter 3 2022–23; AER, Schedule 4 - Quarter 3 2022–23 retail performance data, [data set], accessed 7 November 2023.

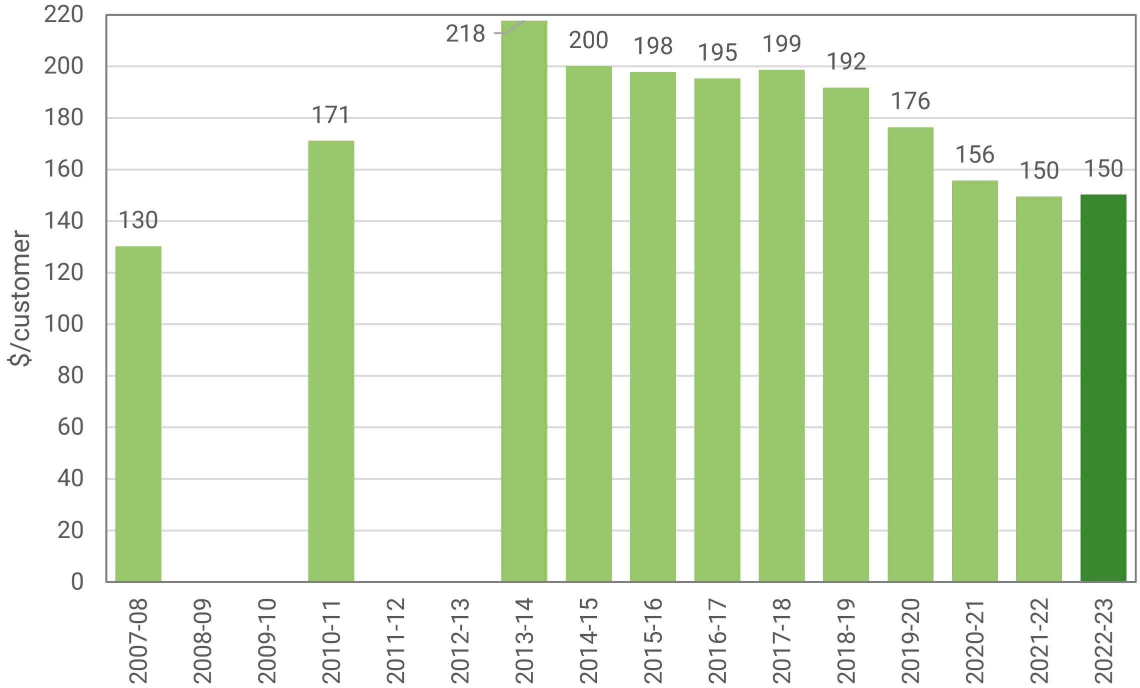
44 A retailer's cost to serve customers includes expenditure on billing, customer service, IT, debt collection and hardship programs.

45 A retailer's cost to acquire and retain customers includes expenditure on marketing and advertising, customer loyalty programs, and third-party sales.

46 ACCC, *Inquiry into the National Electricity Market: November 2022 report* , pp 66 to 76.

Figure 2.15 Retail and other costs for residential customers plateaued in the National Electricity Market in 2022–23

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



Source: ACCC analysis of retailers' data.

3. Retail pricing

Key Points

- For the first time in this inquiry, we collected retail prices from retailers, using our compulsory information gathering powers, to understand how retailers are changing prices for their existing customers on market retail contracts (or plans).
- In jurisdictions with retail competition, the majority of customers are on plans with prices which are determined by retailers. About 10% of residential customers and 20% of small business customers are on standard retail contracts with standing offer prices which are capped by the Default Market Offer or Victorian Default Offer.
- Importantly, prices for existing customers are not publicly available and prior analysis of market offer prices by the ACCC and other regulators has focused on competitive offers currently in the market on government comparison websites.
- Using our new data set, we compare prices for existing customers to the default offer prices, to understand how prices for existing customers compare to regulated prices.
- We also compare prices to publicly available offers on government comparison websites. This helps us understand how outcomes for existing customers compare to acquisition offers. In this way we simulate a comparison of non-observable prices to publicly visible offers at the point of acquisition, which is where competition for customers occurs.
- Our analysis also helps us understand the benefits of competition (in the form of lower prices) that are available to customers if they are able to engage in the market and continue to engage in the market.
- Our analysis relies on model usage assumptions, does not account for all variables that make up an energy plan, and does not reflect actual bills paid. Individual customers should use their actual electricity usage and actual level of solar exports, if applicable, to compare energy plans.
- We analysed our sample of flat rate plans for over 5 million existing residential customers, assuming achievement of conditional discounts, and found that, in August 2023:
  - 47% of all residential customers were on plans with a calculated annual cost equal to or higher than the default offer
  - 42% of concession customers were on plans with a calculated annual cost equal to or higher than the default offer
  - 79% of residential customers in our sample could achieve a better offer by switching to a competitive acquisition offer in Energy Made Easy or Victorian Energy Compare.
- 96% of residential customers on plans with an unconditional price more than 25% above the default offer have a conditional discount in 2023. The customer-weighted average conditional discount for this group of customers is 29%, indicating they have not changed plan or retailer in the last 3 years since the introduction of rules on conditional discounts.

- When we assume conditional discounts are achieved, customers with large conditional discounts are still paying prices around the default offer prices, suggesting that these customers would benefit from switching energy plan.
- Our analysis shows that default offers are constraining prices for competitive acquisition offers, as retailers must set their prices at a discount to attract new customers. However, they do not necessarily constrain how retailers set prices for their existing customers.
- While the vast majority of publicly observable acquisition offers are set at a discount to the default offers, approximately half of existing customers are on prices set at or above the default offers. This means that lower prices are available, but more customers need to be supported to engage in the market to receive the benefits of competition.
- In response to these findings, we recommend that:
  - policy makers should investigate how best to reduce the number of customers on legacy plans with large conditional discounts as a matter of priority
  - a holistic review of the Electricity Retail Code, scheduled to commence in November 2024, should consider barriers to consumer engagement, the increasing complexity of retail tariff structures and the impact of recent reforms introduced after the Electricity Retail Code.

This chapter focuses on retail pricing for existing residential and small business customers in New South Wales, Victoria, South East Queensland, and South Australia in 2022 and 2023.

To inform this chapter, the ACCC issued compulsory information gathering notices to retailers to capture information on their retail prices, price change process, and pricing strategies.

In this chapter, we:

- examine the change in flat rate market offer prices between 1 August 2022 and 1 August 2023
- examine how flat rate market offer prices compare to the Default Market Offer and Victorian Default Offer prices (**default offers**) and to competitive acquisition offers on government comparison websites, Energy Made Easy and Victorian Energy Compare
- examine price dispersion in the market, including whether market offer customers are experiencing the 'loyalty penalties' that the standing offer price cap was introduced to limit
- examine changes in retailer pricing behaviours as a result of price re-regulation
- outline existing reforms and potential policy responses to address disengagement, conditional discounts, and consumer confidence in the market.

3.1. What are standing offers, market offers and default offers?

There are 2 types of customer retail contracts under the National Energy Retail Law[47] and Victorian Energy Retail Code of Practice:

- standard retail contracts (**standing offers**)
- market retail contracts (**market offers**).

Approximately 90% of residential and 80% of small business customers are on market offers.[48]

There are several differences between standing and market offers which relate to how the contracts are formed and the types of consumer protections that apply. These differences are a result of the evolution of retail competition in the National Electricity Market (NEM) which saw state and territory governments retain standard retail contracts to provide a safety net for consumers who had not or could not engage in the market (see section 2.5).

As outlined in Chapter 2, most standing offer prices were re-regulated in 2019 through the introduction of the Victorian Default Offer and Default Market Offer. At the same time, retailers were required to start comparing prices against the default offer prices to make it easier for consumers to compare electricity plans.

This means that when retailers advertise prices, they are discounting off the Victorian Default Offer and Default Market Offer prices (for example, 15% off the Victorian Default Offer).

Although broadly similar, the Default Market Offer and Victorian Default Offer operate differently, are set by different regulators, and have different guiding principles and objectives.

The Default Market Offer consists of 2 components: an annual reference price ($/year) and model annual usage (kWh/year). Retailers are able to set their own supply and usage charges, so long as the total annual cost does not exceed the reference price at the model annual usage.[49] It does not apply to plans with demand charges or to small business time-of-use or controlled load plans.[50]

The Default Market Offer was not intended to be the lowest price, or close to the lowest price in the market. It was intended to be set above the price for competitive acquisition offers to avoid incentivising consumer disengagement and would ideally be used by only a small number of consumers.[51]

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47 Adopted by New South Wales, Queensland, South Australia, Tasmania, and the Australian Capital Territory.

48 ACCC, *Inquiry into the National Electricity Market: June 2023 report*, ACCC, Australian Government, 30 June 2023, p 28.

49 Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (Cth) s 10.

50 Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (Cth) s 6.

51 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry Final Report*, ACCC, Australian Government, 2018, p 249.

The policy objectives of the Default Market Offer are to:[52]

- reduce unjustifiably high standing offer prices and continue to protect consumers from unreasonable prices
- allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention
- maintain incentives for competition, innovation and investment by retailers, and incentives for consumers to engage in the market.

The objective of the Victorian Default Offer is to provide a simple, trusted and reasonably priced option that safeguards customers unable or unwilling to engage in the retail electricity market without impeding the consumer benefits experienced by those who are active in the market.[53] In setting the Victorian Default Offer, the Essential Services Commission of Victoria is required to base prices on the efficient costs of supplying retail electricity.

The Victorian Default Offer specifies prices to be charged to customers for flat rate and simple time-of-use tariffs and sets a maximum annual bill amount and usage assumption to be complied with for other tariff types.

To set the Default Market Offer and Victorian Default Offer prices in 2022–23 and 2023–24, both the Australian Energy Regulator and the Essential Services Commission of Victoria used a cost build-up approach.

This means that the regulator forecasts the network, wholesale, environmental and retail costs[54] on a per-customer basis for each distribution region, before adding a retail margin to reflect a reasonable rate of return. The Default Market Offer also includes an additional retail allowance, often termed ‘headroom’, that the Victorian Default Offer does not include. This additional retail allowance is intended to provide room for retailers to effectively compete.[55]

3.2. Retailers are charging higher electricity prices in 2023

For the first time in this inquiry, we collected retail prices from retailers, using our compulsory information gathering powers, to understand how retailers are changing prices for their existing market offer customers. This is a new dataset that helps us understand the level and spread of retail electricity prices. Together, the retailers we collected information from supply electricity to 4 in 5 customers in New South Wales, Victoria, South East Queensland, and South Australia.

Specifically, we collected retail prices of all flat rate and flat rate with controlled load residential plans and of all flat rate small business plans with customers as at 1 August 2022 and 1 August 2023, to understand how prices have changed for retailers’ existing customers in the context of widely reported price increases.

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52 AER, *Default market offer prices 2023–24: Final determination*, p 39.

53 ESC, Fair Pricing in the Energy Market: Terms of Reference for the Essential Services Commission, ESC, Victorian Government, 21 December 2018, p 1; Minister for Energy, Environment and Climate Change, ‘Order under section 13 of the *Electricity Industry Act 2000*’ in Victoria, Victoria Government Gazette, No S 208, 30 May 2019, p 1.

54 Both the AER and ESC are required to include costs to acquire and retain customers in setting the Default Market Offer and Victorian Default Offers, respectively.

55 AER, *Default Market Offer prices 2023–24: Final determination*, p 39.

This dataset does not tell us how much in total consumers are paying or being charged, as electricity bills are dependent on usage. We last comprehensively reported on bill outcomes in our June 2023 report, which examines the change in bills up to September 2022.

As discussed in Chapter 2, retailers incurred higher wholesale electricity costs in 2022–23 than in previous years, which ultimately are passed through to consumer bills. Changes in retailers' costs take time to flow through to retail prices and, even more belatedly, actual billing outcomes experienced by consumers.[56] This is because retail prices are set prospectively using cost forecasts, before actual costs are incurred, and customers are billed in arrears.

While our billing analysis provides stakeholders with accurate information on the actual costs faced by consumers, it is retrospective and not current or prospective. In contrast, the prices we collected as at 1 August 2023 are still likely to be reflected in consumer bills at the time of publication.[57]

Retailers typically undertake a repricing process on an annual basis, generally changing prices around 1 July in New South Wales, South East Queensland and South Australia, and 1 August in Victoria.[58]

Out of cycle price increases have also been observed, as retailers in New South Wales, South Australia, and South East Queensland, can change prices for customers on variable market offer plans at any time, provided they give at least 5 business days' notice.[59] In Victoria, retailers are only able to increase prices once per year but can decrease prices at any time.[60]

Customers are also able to change plans or retailers at any time, depending on the terms of their contract. Many customers are on ongoing or evergreen market retail contracts, which means they are not required to regularly reengage with the market and may stay with the same retailer or on the same plan for a long period of time, while continuing to receive unilateral price increases.

As we asked for prices on a point-in-time basis, we also asked retailers for information about when they changed their prices, the proportion of customers affected, and the customer-weighted average change in price. While some retailers changed their prices in 2022 after 1 August 2022, all retailers surveyed had changed their prices at least once in every state in 2023 by 1 August 2023.

This means that prices collected as at 1 August 2022 were not necessarily charged for the whole of 2022–23 and prices collected as at 1 August 2023 may be charged to customers for all or only part of 2023–24.

56 ACCC, *Inquiry into the National Electricity Market: June 2023 report*, p 2.

57 For further information about the differences between our billing analysis and the analysis in this chapter in regard to comparing standing offer and market offer prices, see Appendix B: Methodology for data collection and analysis.

58 Price increases in Victoria may only be made on a network tariff change date (1 August). See Energy Retail Code of Practice (Victoria) cl 94.

59 National Energy Retail Rules r 46.

60 On 1 July 2020, the Essential Services Commission introduced price certainty rules to protect residential and small business consumers from unexpected energy price increases. These rules mean energy retailers are only allowed to increase prices once a year. For many customers, this will happen on a set date one month after network tariff prices change (usually on 1 August each year). Customers on fixed-price contracts will only experience any price increases on the anniversary of their initial fixed-price period expiring.

The prices we collected included supply charges, usage charges, controlled load charges, solar feed-in tariffs, proportional conditional discounts, proportional unconditional (guaranteed) discounts and GreenPower charges.[61] We also collected the number of customers on each plan. In total, the prices we collected apply to over 5 million residential customers and 400,000 small business customers, representing approximately 60% and 50% of the total number of residential and small business customers respectively.

To compare these different prices, we have, in the first instance, calculated an annual cost using the annual usage in the Default Market Offer and Victorian Default Offer determinations. In calculating the annual cost, we have excluded proportional conditional discounts, solar feed-in tariffs and GreenPower charges. However, we have included proportional guaranteed discounts in calculating the annual cost, as they amount to lower prices, albeit communicated in a less transparent way, and do not represent additional value.

We have then determined a customer-weighted average price, by taking the calculated annual cost of each plan and weighting it by the number of customers.

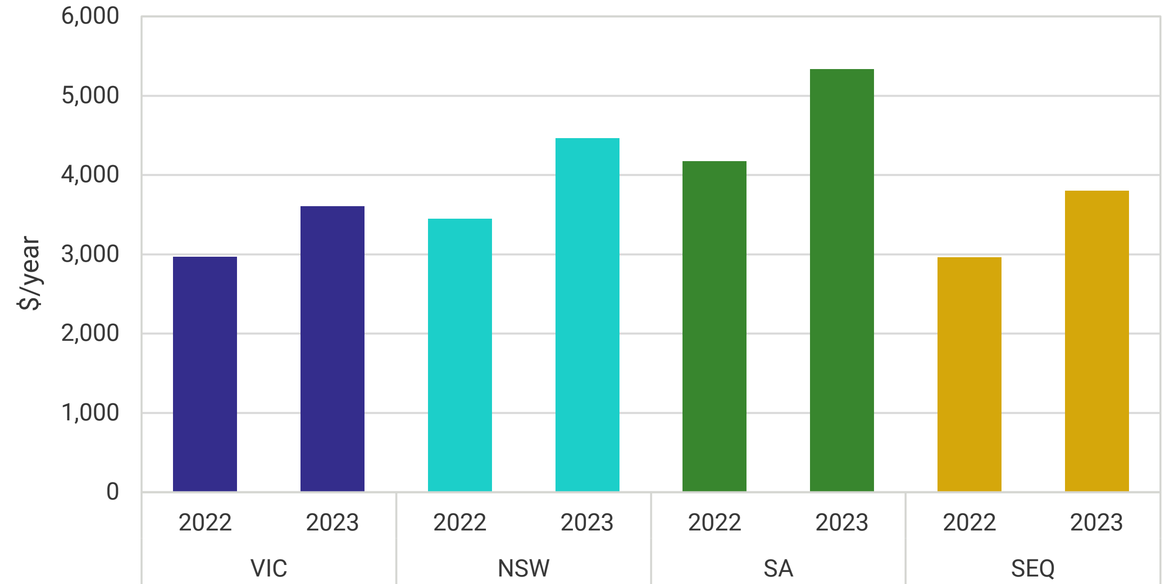
The customer-weighted average annual price for each tariff type and state is presented in Figure 3.1. It shows that prices increased by between 11.3% (Victoria) and 35.6% (New South Wales) year-on-year for residential flat rate customers with controlled load tariffs and by between 22.4% (Victoria) and 33.9% (New South Wales) for residential flat rate only customers, depending on the state. For small business customers on flat rate offers, prices increased by between 21.4% (Victoria) and 29.5% (New South Wales) year-on-year, depending on the state.

[61] We explained the kinds of prices, fees, charges, and benefits which make up an energy plan in section 3.1 of our June 2023 report. See: ACCC, *Inquiry into the National Electricity Market: June 2023 report*, p 24.

Figure 3.1 Prices are considerably higher for customers on flat rate market offer plans in 2023

Customer-weighted average unconditional annual price, residential customers by tariff type and year, all regions, nominal, GST inclusive.

Customer-weighted average unconditional annual price, small business customers on flat rate tariffs by year, all regions, nominal, GST inclusive.



Source: ACCC analysis of retailers' data.

Notes: 2022 prices as at 1 August 2022 and 2023 prices as at 1 August 2023. Customer-weighted average annual price includes supply and usage charges and guaranteed discounts only and is calculated using the model annual usage assumptions, which differ by state. Solar feed-in tariffs, conditional discounts and GreenPower charges are excluded. See Appendix C for a version of this figure inclusive of conditional discounts. See Appendix B for details about the model annual usage assumptions used for each distribution region and state.

3.3. More customers are paying prices equal to the default offer prices

As set out in section 3.2, we calculated an annual cost using the annual usage in the Default Market Offer and Victorian Default Offer determinations for each plan in our data set.

This calculated annual cost excludes solar feed-in tariffs and proportional conditional discounts.

We then compared those annual costs against the equivalent Default Market Offer and Victorian Default Offer prices to see how many customers in our sample were being charged prices higher or lower than the regulated default offer price.

In the course of undertaking this analysis, we observed that plans with a calculated annual cost above the equivalent default offer often included proportional conditional discounts. We discuss this correlation further in section 3.4 below. In our June 2023 report, we found that 91% of residential customers and 85% of small business customers in our sample achieved their conditional discounts as at 1 July 2022.[62]

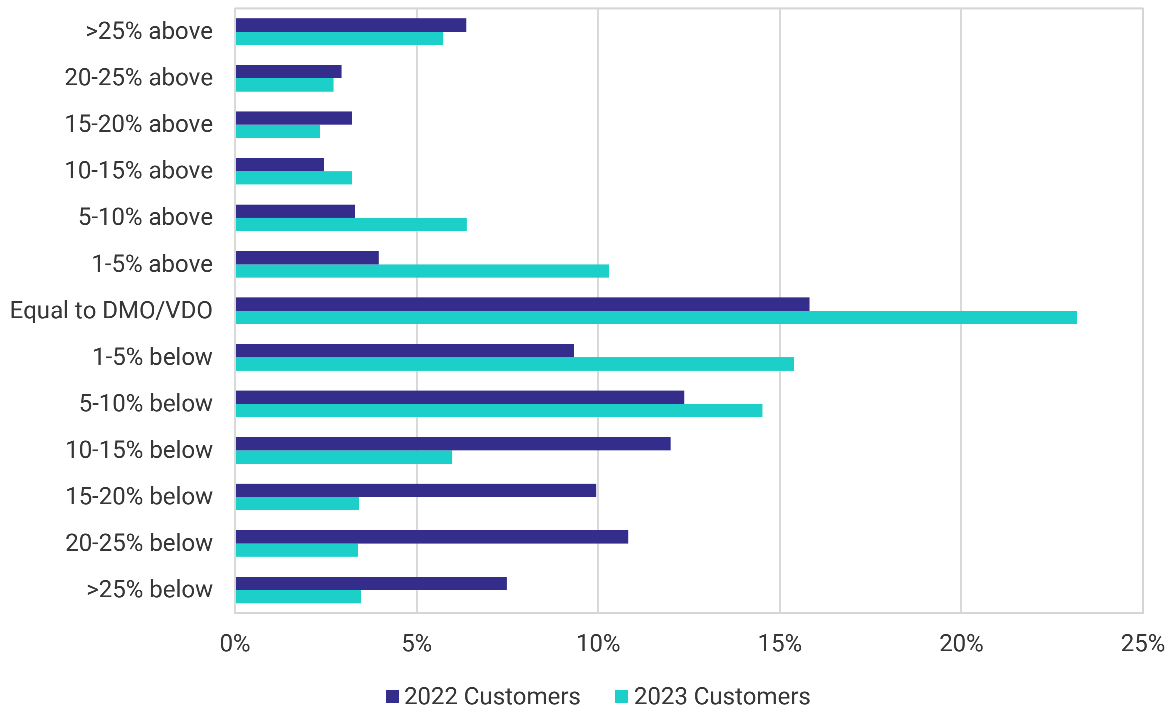
Given the high overall rate of achievement of conditional discounts, we have also presented the distribution of customers by discount tier to the Default Market Offer and Victorian Default Offer prices for 2022–23 and 2023–24, assuming 100% of conditional discounts are achieved.

Figure 3.2 and Figure 3.3 show these distributions for residential and small business customers respectively.

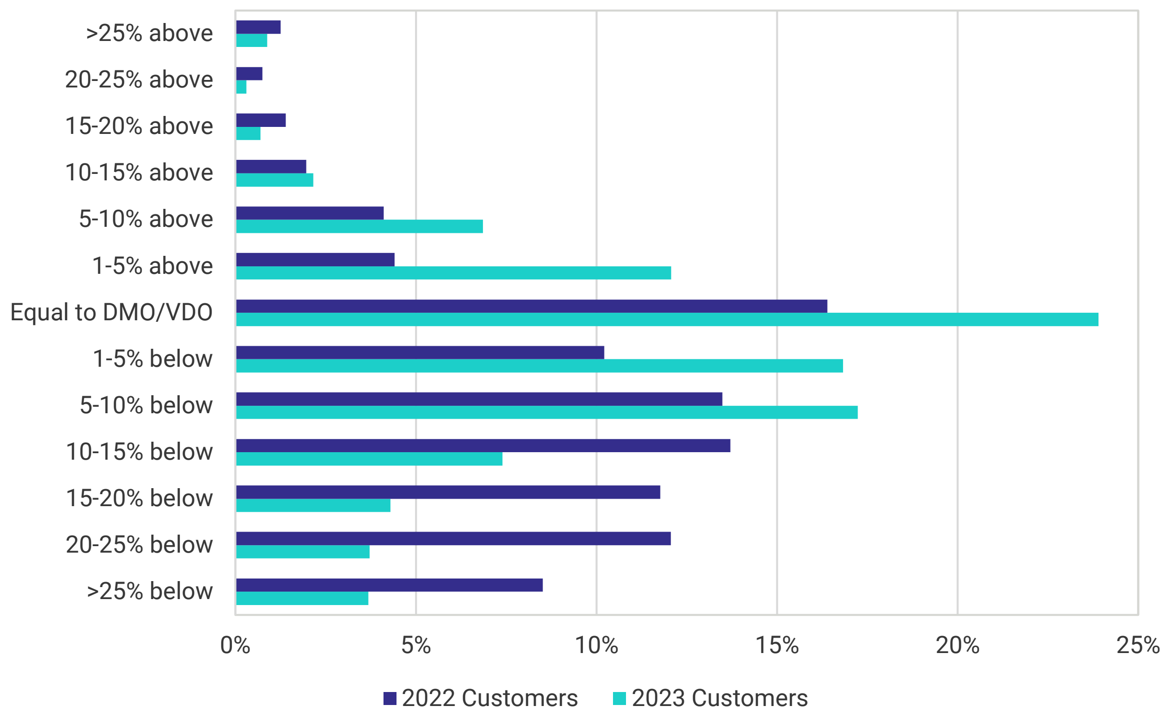
[62] ACCC, *Inquiry into the National Electricity Market: June 2023 report*, , Appendix E: Data appendix [data set].

Figure 3.2 More residential flat rate market offer customers are paying prices equal to the default offers

Proportion of residential customers on flat rate plans paying more, equal to, or less than the DMO/VDO, assuming conditional discounts are not achieved



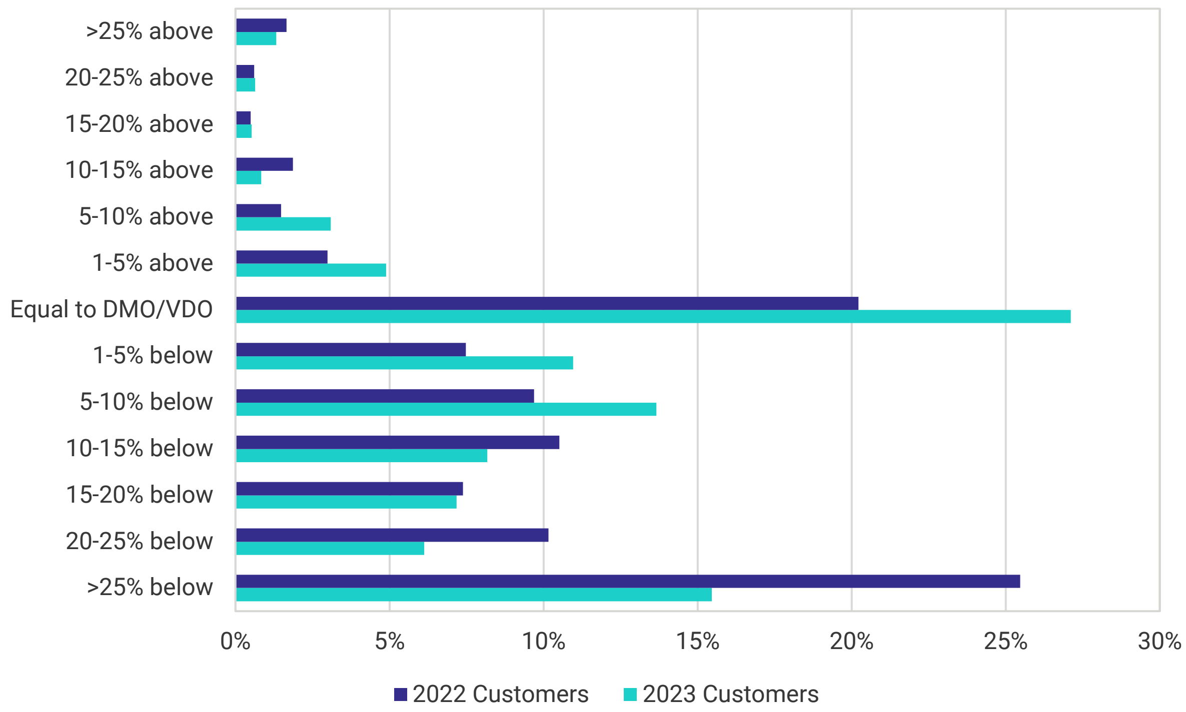
Proportion of residential customers on flat rate plans paying more, equal to, or less than the DMO/VDO assuming 100% achievement of conditional discounts



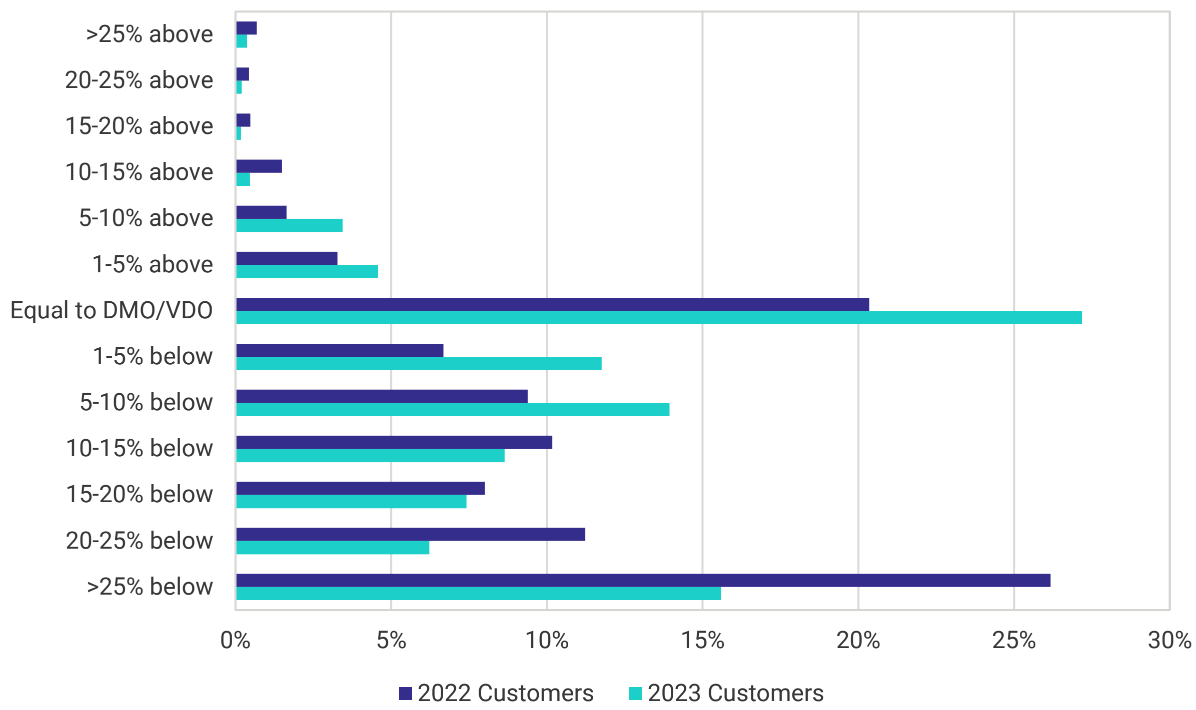
Source: ACCC analysis of retailers' data.

Figure 3.3 Prices for small business customers on flat rate plans have also converged around the default offer prices

Proportion of small business customers on flat rate plans paying more, equal to, or less than the DMO/VDO assuming conditional discounts are not achieved



Proportion of small business customers on flat rate plans paying more, equal to, or less than the DMO/VDO assuming 100% achievement of conditional discounts



Source: ACCC analysis of retailers' data.

While prices were dispersed above and below the Default Market Offer and Victorian Default Offer in both 2022 and 2023, the proportion of residential customers on plans with a calculated annual cost at or above the Default Market Offer and Victorian Default Offer increased from 38% in 2022 to 54% in 2023, assuming conditional discounts were not achieved (Figure 3.2).

Similarly to residential customers, the proportion of small business customers on plans with a calculated annual cost at or above the Default Market Offer and Victorian Default Offer increased from 29% in 2022 to 38% in 2023, assuming conditional discounts were not met (Figure 3.3). This included an increase of 7% for both residential and small business customers in the proportion of customers on plans with a calculated annual cost equal to the Default Market Offer and Victorian Default Offer.

When we assumed conditional discounts were achieved 100% of the time, the proportion of residential customers on plans with a calculated annual cost at or above the default offers reduced to 30% in 2022 and 47% in 2023.

However, the proportion of residential customers on plans with a calculated annual cost between 5% below and 5% above the default offers in 2023 increased from 49% to 53% when we assumed achievement of conditional discounts 100% of the time. We also see the number of offers with a calculated annual cost greater than 10% above the default offers decrease from 14% to 4%. These results show a convergence towards the default offer prices even when we assume 100% achievement of conditional discounts.

This convergence of market offer prices toward standing offer prices is also shown when we compare the customer-weighted average price increase to the change in the Default Market Offer and Victorian Default Offer prices (Table 3.1) between 2022 and 2023. In most regions, with the exception of Victoria, the change in the customer-weighted average unconditional price is greater than the change in the equivalent regulated standing offer price, suggesting market offer prices were further away from standing offer prices in 2022. When we include conditional discounts in our calculation of annual cost in 2022 and 2023, we see a slightly larger change between 2022 and 2023 (refer Appendix C). This accords with our findings above.

Table 3.1 Market offer prices for residential customers on flat rate market offer plans increased by more than regulated standing offer prices, leading to a convergence around the DMO/VDO

Year-on-year change in Default Market Offer and Victorian Default Offer prices (1 July 2022 to 1 July 2023) and customer-weighted average unconditional prices (1 August 2022 to 1 August 2023), residential customers, nominal

Distribution Region	Flat rate			Flat rate with controlled load		
	DMO/VDO		Average price	DMO/VDO		Average price
New South Wales						
Ausgrid	20.8%	↑	35.7%	20.7%	↑	39.6%
Endeavour Energy	21.4%	↑	33.4%	24.9%	↑	38.0%
Essential Energy	20.8%	↑	30.0%	19.6%	↑	30.1%
Victoria						
Ausnet Services	24.1%	↓	23.5%	28.4%	↓	14.2%
CitiPower	21.5%	↓	19.5%	26.1%	↓	6.6%
Jemena	27.2%	↓	23.4%	31.9%	↓	5.5%
Powercor	27.0%	↓	23.4%	32.2%	↓	15.0%
United Energy	25.9%	↓	21.9%	30.9%	↓	5.5%
South East Queensland						
Energex	21.5%	↑	31.1%	20.5%	↑	31.5%
South Australia						
SA Power Networks	23.9%	↑	24.8%	22.5%	↑	27.1%

Source: ACCC analysis of retailers' data, Victorian Default Offer prices, and Default Market Offer prices.

Notes: See Appendix C for a version of this table with values calculated inclusive of conditional discounts.

The convergence towards the regulated default offer prices reflects a reduction in price dispersion in the market.

In 2018, we expressed concerns that there was a significant amount of price dispersion in retail electricity markets which was not a result of efficient price discrimination, but rather confusing discounting practices, information asymmetries and barriers to switching.[63]

It was in this context that the ACCC recommended a range of reforms, including the Default Market Offer, to protect disengaged consumers and ensure consumers could better compare plans.

[63] ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry Final Report*, , p 259.

The Australian Energy Market Commission's advice prior to the implementation of the Default Market Offer considered:

- Retailers would respond to the introduction of the default offer by attempting to increase market offer prices.
- This would result in a reduction in the price of standing offers and high-priced market offers, and price increases in the lower priced market offers available to customers.
- Depending on the level of the Default Market Offer, the only way for retailers to recover a revenue shortfall would be to set market offer prices above the default offer, which was considered to be 'clearly not a feasible outcome but does illustrate the potential detrimental implications for retail competition if the default offer is set too low.'[64]

While setting acquisition prices above the Default Market Offer and Victorian Default Offer may not be feasible for retailers seeking to acquire new customers, as customers would opt for the default offer instead, it is clear from our analysis of flat rate plans that retailers have set prices for their existing customers above the default offer prices.

3.3.1. Price outcomes are similar for concession customers

Retailers were also required to identify the number of concession customers on each residential flat rate market offer plan. Our definition of a concession customer is a customer eligible for financial assistance from the government in the form of a rebate, discount or subsidy that relates to the customer's electricity bill.

The broad rationale behind energy concession schemes is to assist consumers who might otherwise experience forms of energy poverty, such as struggling to pay for electricity or opting to under-consume electricity through restricting heating and cooling to reduce their electricity costs. Concession schemes are therefore important for ensuring vulnerable consumers continue to have access to electricity, given it is an essential service.

Each state and territory has different energy concession schemes with different eligibility criteria. In Appendix B to our June 2023 report, we provided a detailed breakdown of electricity concessions and rebates for households by region. This breakdown shows that many concession schemes provide a lump sum rebate or subsidy. These schemes therefore can have a greater impact on a concession customer's overall cost-of-living when the customer's electricity plan has lower underlying prices.

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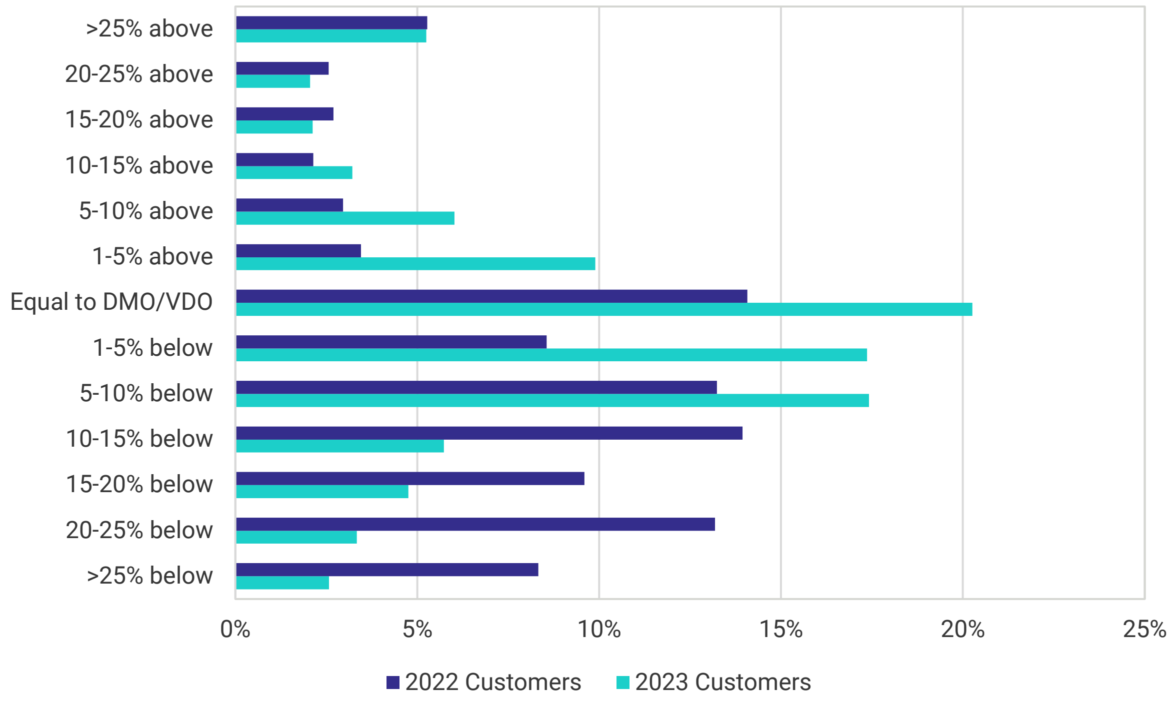
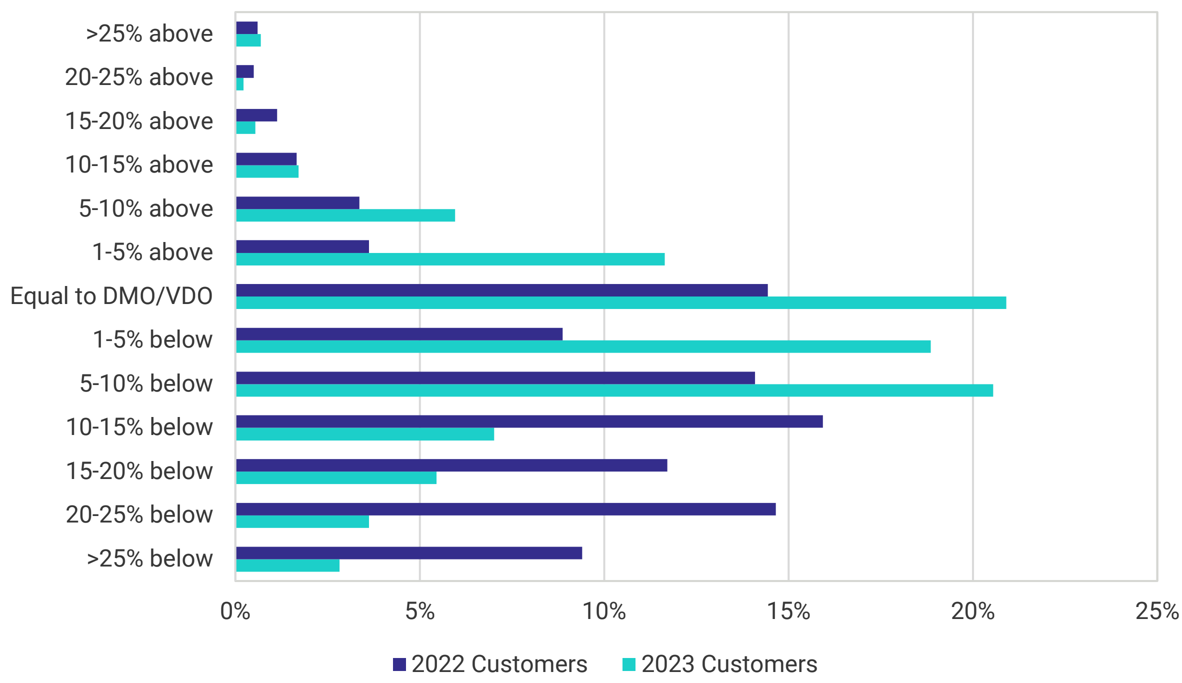
64 Australian Energy Market Commission (AEMC), *Advice to COAG Energy Council: Customer and competition impacts of a default offer*, AEMC, Australian Government, 2018, p v.

Figure 3.4 Price outcomes for existing customers with concessions

Proportion of residential concession customers on flat rate and flat rate with controlled load market offer plans paying more, equal to, or less than the DMO/VDO, assuming conditional discounts are not achieved, all regions



Proportion of residential concession customers on flat rate and flat rate with controlled load market offer plans paying more, equal to, or less than the DMO/VDO, assuming 100% achievement of conditional discounts, all regions



Source: ACCC analysis of retailers' data.

Approximately 25% of customers in our data set were identified by retailers as concession customers. The unconditional price outcomes for concession customers (Figure 3.4) are broadly similar to the outcomes for all residential customers:

- 49% of concession customers are paying unconditional prices at or above the Default Market Offer or Victorian Default Offer in 2023, compared to 33% in 2022 (compared to 54% and 38% for all residential customers)
- The proportion paying between 1–10% below increased from 22% in 2022 to 35% in 2023 (compared to 22% and 30% for all residential customers)
- The proportion paying 10% or more below decreased from 45% in 2022 to 16% in 2023 (compared to 40% and 16% for all residential customers).
- When conditional discounts are assumed to be achieved 100% of the time, we see 42% of concession customers in 2023 on calculated annual costs equal to or above the Default Market Offer or Victorian Default Offer, compared to 25% in 2022.

As the distribution is broadly similar to that of all residential customers, this suggests that many concession customers are on electricity offers which would not be well aligned with their ability to pay.

When concession customers are on higher prices than they need to be, energy concession schemes have less impact on bill outcomes. Ultimately, the lower underlying prices are for concession customers, the less they have to pay once their concession is applied.

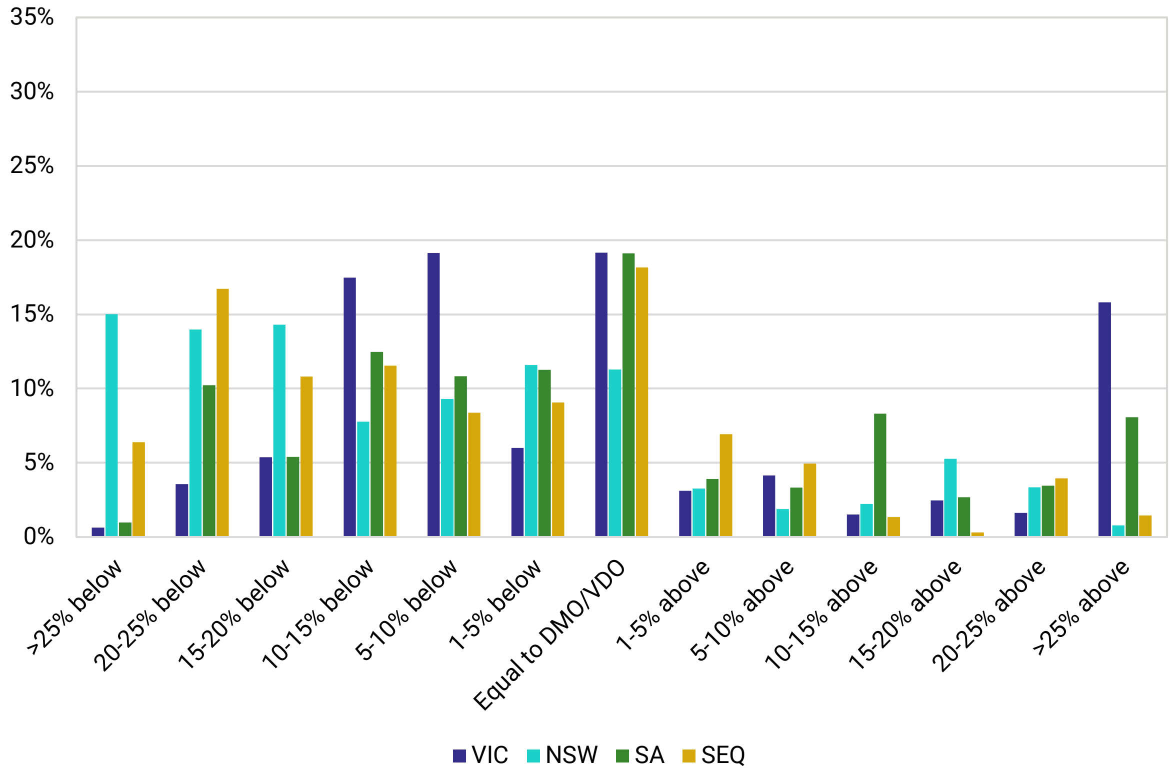
3.3.2. Price outcomes are influenced by regional factors and determined by retailers

When we present the same information in Figure 3.2 above on a state-by-state basis, we see considerable variation in outcomes. For instance:

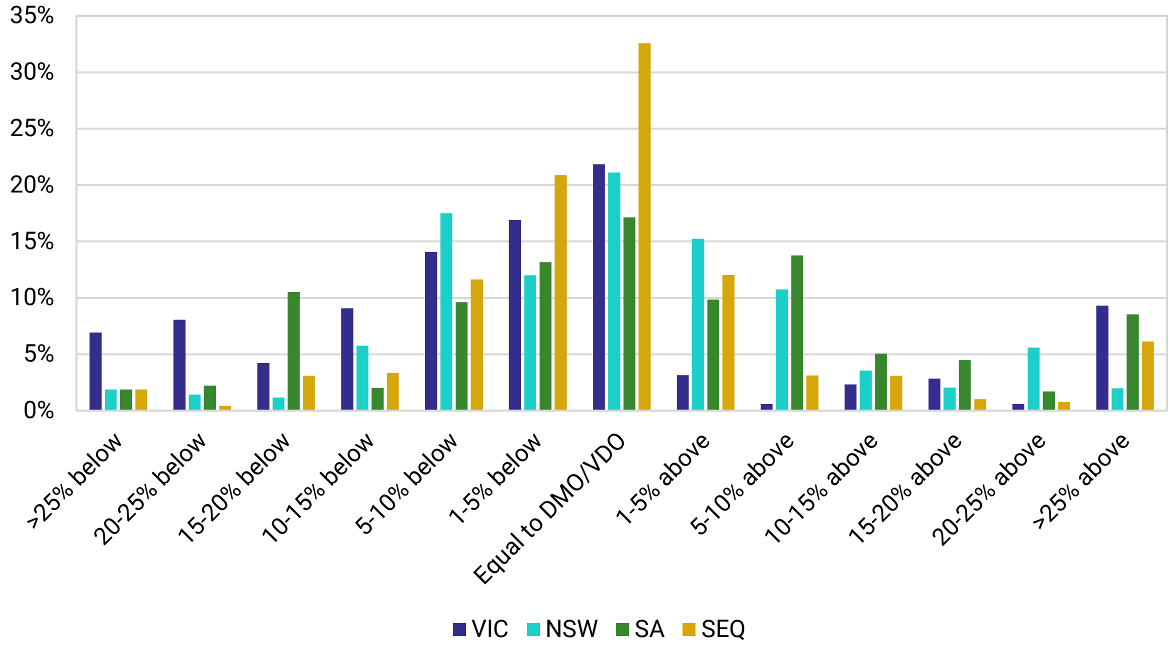
- in South East Queensland, the proportion of residential customers paying annual prices equal to the Default Market Offer in 2023 is considerably larger than in other states
- in Victoria, the proportion of residential customers on annual prices more than 25% above the Victorian Default Offer in 2022 is larger than in other states, but comparable to South Australia in 2023
- in New South Wales, South Australia and South East Queensland, the proportion of residential customers paying annual prices more than 20% below the Default Market Offer decreased between 2022 and 2023, while the opposite occurred in Victoria.

Figure 3.5 Pricing outcomes vary between regions

Proportion of residential customers on flat rate plans paying annual unconditional prices that are more, equal to, or less than the DMO/VDO in 2022 by state



Proportion of residential customers on flat rate plans paying annual unconditional prices that are more, equal to, or less than the DMO/VDO in 2023 by state



Source: ACCC analysis of retailers' data.

Note: See Appendix C for a version of this figure inclusive of conditional discounts.

There are a number of underlying reasons for this regional variation, with one key reason being that the change in the regulated default offer price (our benchmark) between 2022 and 2023 is different for each state (see Table 3.1).

Another key reason is that prices are determined by retailers in accordance with their pricing policy and pricing strategy. Retailers typically take a cost build-up approach to setting prices in the first instance to ensure cost recovery. Prices may then be adjusted up or down to achieve target profit margins, ensure regulatory compliance, retain market competitiveness, and reduce customer churn, among other considerations.

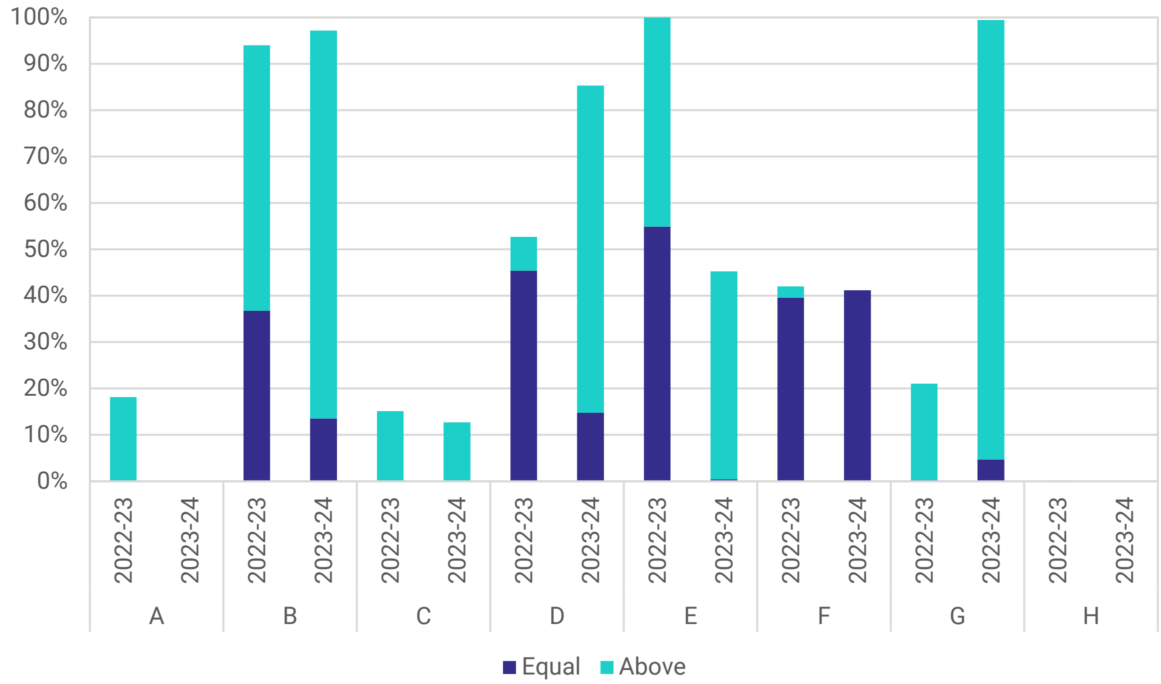
If a retailer has a large market share in a state, its approach to setting prices may impact the overall result. For instance, if a retailer with 30% market share in a state chooses to set prices for all customers below the default offer, then at least 30% of customers in that state will be on prices below the default offer.

To complement our analysis of flat rate with or without controlled load plans, each retailer was also required to report the proportions of customers paying more, equal to or less than the equivalent standing offer price by tariff type for each distribution region.

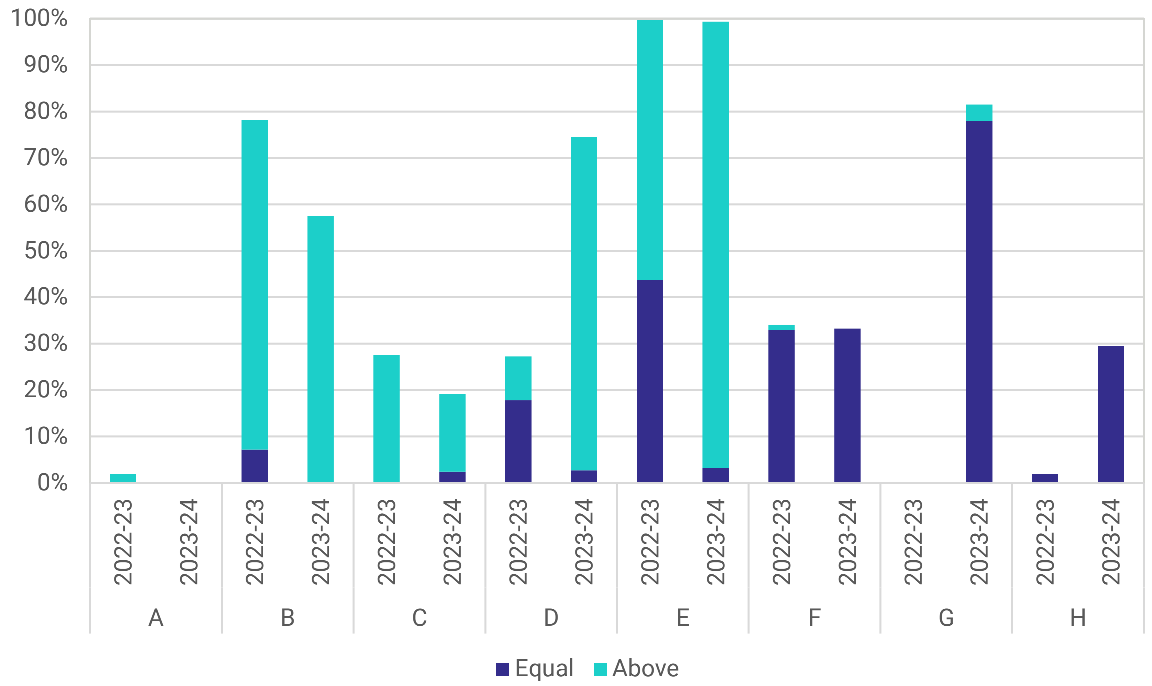
Figure 3.6 shows the proportions reported by each retailer for time-of-use residential customers in 2 distribution regions: SA Power Networks in South Australia and Ausgrid in New South Wales.

Figure 3.6 Pricing approaches vary between retailers

Proportion of residential customers on time-of-use only tariffs paying equal to or more than the DMO by retailer (anonymised) and year, SA Power Networks distribution region



Proportion of residential customers on time-of-use only tariffs paying equal to, or more than the DMO by retailer (anonymised) and year, Ausgrid distribution region



Source: ACCC analysis of proportions reported by retailers.

Notes: 2022-23 proportions reported as at 30 June 2023. 2023-24 proportions reported as at 10 August 2023. The ACCC did not specify a methodology to be used in calculating the proportions.

As shown above, each retailer sets prices differently – some retailers set prices for most customers above the default offer, while other retailers had no customers priced above. The same retailer may also have customers priced above in one distribution region, but not in another distribution region.

This may be for reasons including that the retailer's costs are lower relative to the cost inputs used to set the default offer, or that the retailer is seeking to acquire or retain market share.

3.3.3. On average, solar feed-in tariffs do not increase with prices

As of August 2023, more than 3 million households and businesses have installed rooftop solar photovoltaic systems across the NEM.[65] By installing solar panels, consumers are able to reduce their grid electricity usage and receive solar feed-in tariff credits for exporting excess solar generation to the grid. This means that the level of solar feed-in tariff is important for many consumers, as it reduces the total cost of electricity.

However, as mentioned above, we excluded solar feed-in tariff rebates from our calculated annual cost because the default offer determinations do not include assumptions about the level of solar exports. Arriving at a representative export level to account for solar feed-in tariffs is difficult as there is considerable variation in the size of solar systems, level, and pattern of grid consumption.

To address this, we have performed a separate analysis of the level of solar feed in tariffs available to customers in our sample. We find that, although individual outcomes may vary, for most customers, better priced offers are available even when we account for the size of the solar feed in tariff.

Some electricity retailers offer targeted solar plans that typically have a higher-than-average solar feed-in tariff rate, but also have higher underlying supply and usage charges. As acquisition offers, these plans are typically priced at or below the default offer prices before accounting for solar feed-in tariffs. Some consumers, especially those with large solar systems who have low grid consumption and high export volumes, may benefit from paying slightly higher prices if they receive a larger solar feed-in tariff.

For customers comparing these plans, a comparison exercise which excludes solar feed in tariffs, will not provide a comprehensive comparison of value. However, by analysing the range of solar feed in tariffs associated with the plans in our data set, we have been able to demonstrate that such a comparison is still instructive as higher solar feed-in tariffs are also available on plans with a calculated annual cost below the default offers in 2023.

65 Clean Energy Regulator, Postcode data for small-scale installations [data set], CER, Australian Government, 15 November 2023.

Box 3.1 Weighing up whether your existing solar offer is a good deal

Our example customer receives a price change notice from their retailer. The notice says that their new prices are 10% above the reference price, assuming they use 4,500 kWh. The reference price is $1,800.

While their supply and usage charges have changed, their solar feed-in tariff has not and will remain high at 16c/kWh.

Our example customer also sees a plan being advertised by another retailer, which is equal to the reference price and includes a solar feed-in tariff of 12c/kWh.

The comparison to the reference price helps our customer understand that the prices for consuming electricity from the grid are lower for the advertised plan.

	Supply charge	Usage charge	Annual cost	% Comparison
New Prices	$1.36/day = $496/year	33 c / kWh = $1,485/year	$1,981	10% above
Advertised plan	$1.23/day = $449/year	30 c / kWh = $1,350/year	$1,799	Equal to

However, our customer has a large solar system, so they need to use their own usage and export volumes to compare their plans.

Our example customer, on average, consumes 7,000 kWh per year and exports 4,000 kWh.

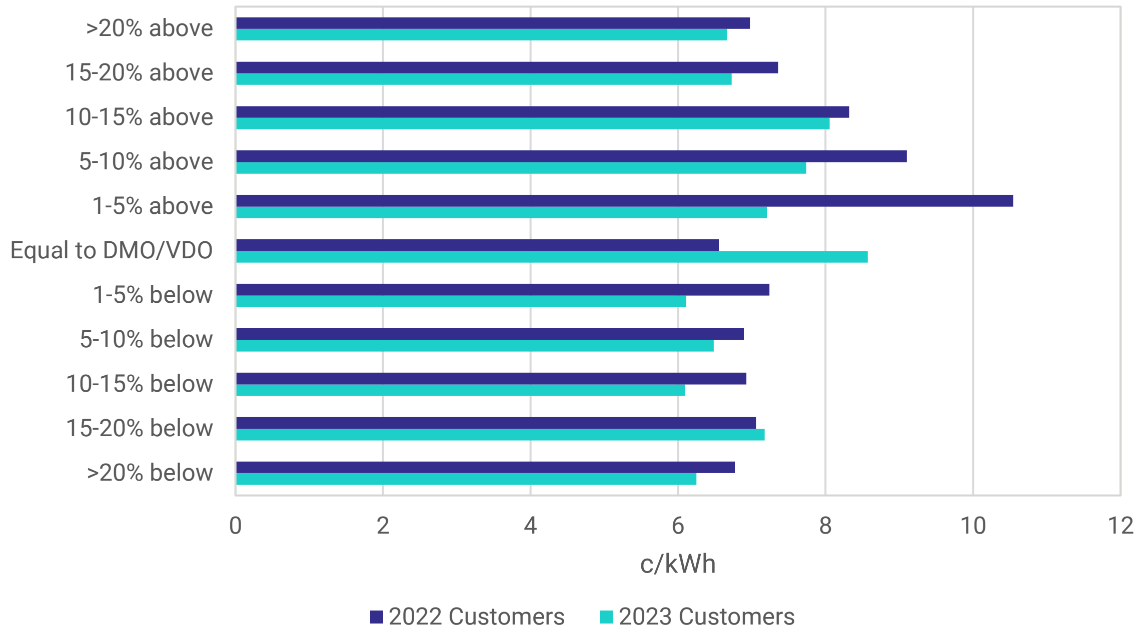
	Supply charge	Usage charge	Solar feed-in	Annual cost
New prices	$1.36/day = $496/year	33 c / kWh = $2,310/year	16c/kWh = - $640	$2,166
Advertised plan	$1.23/day = $449/year	30 c / kWh = $2,100/year	12c/kWh = - $480	$2,069

While the advertised plan is still cheaper, when the customer uses their own electricity consumption and solar export volume, the relative value of the plans change and the gap narrows.

As shown in Figure 3.7, our analysis shows that the customer-weighted average solar feed-in tariff does not uniformly increase as the customer-weighted average calculated annual cost increases. For instance, when we assume conditional discounts are not achieved, customers in 2023 on plans in the 15–20% above tier receive a lower solar feed-in tariff than customers in the 15–20% below tier.

Figure 3.7 The customer-weighted average feed-in tariff does not increase with price

Customer-weighted average solar feed-in tariff for solar residential flat rate and flat rate with controlled load market offer plans by discount tier to the DMO/VDO, assuming conditional discounts are not achieved and excluding offers with subsidised solar feed-in tariffs, all regions



Customer-weighted average solar feed-in tariff for solar residential flat rate and flat rate with controlled load market offer plans by discount tier to the DMO/VDO, assuming 100% achievement of conditional discounts and excluding offers with subsidised solar feed-in tariffs, all regions

Source: ACCC analysis of retailers' data.

Notes: To exclude government subsidised solar feed-in tariffs, we excluded all solar feed-in tariffs which were equal to or greater than 44c/kWh. See Appendix B for additional qualifications about this figure.

The above analysis indicates that solar customers can receive both a higher solar feed-in tariff and pay higher underlying prices for electricity consumed from the grid, but that better offers are also available relative to the default offer. While solar plans with higher underlying prices and higher solar feed in tariffs will have reduced comparability to other offers, this is easily overcome by customers using their historical electricity consumption and solar export volume, when comparing energy plans, to ensure they are on the best possible offer for their circumstances, as shown in the worked example in Box 3.1.

3.4. Higher prices correlate with large conditional discounts

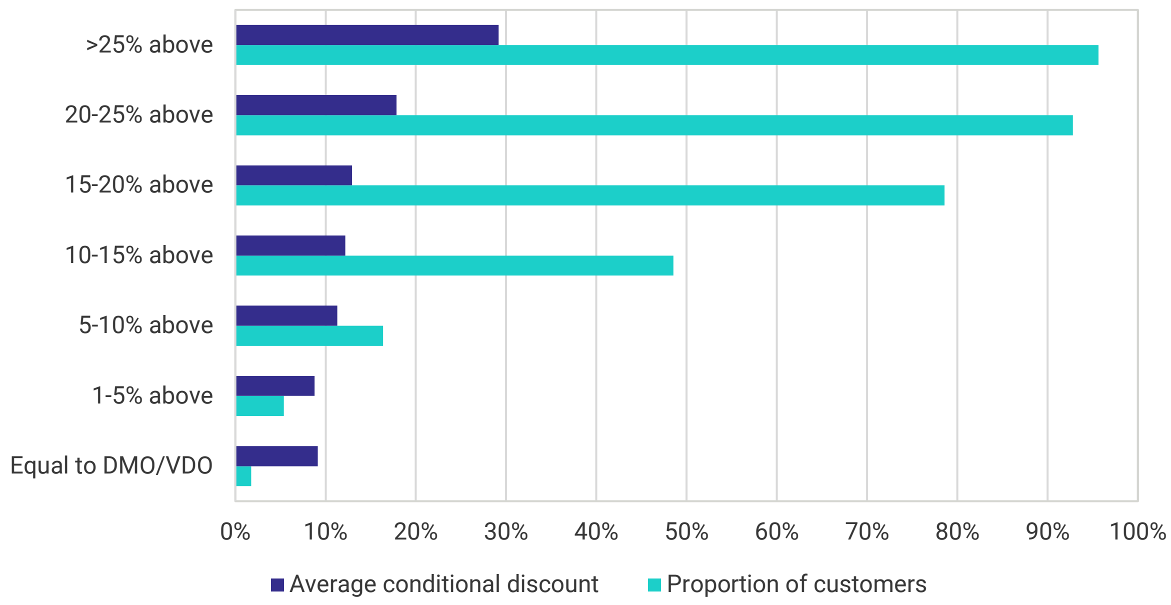
When we examined the relationship between conditional discounts and unconditional price, we saw a strong relationship (see section 3.3 above). There were very few customers paying unconditional prices significantly above the Default Market Offer and Victorian Default Offer that did not have a conditional discount.

The below chart shows that the majority of residential customers on higher priced plans have conditional discounts and that the size of these conditional discounts increases the further away the underlying prices are from the Default Market Offer and Victorian Default Offer:

- 79% of the 2% of residential customers paying unconditional prices between 15–20% above the default offers have conditional discounts in 2023. This equates to about 95,000 customers with a customer-weighted average conditional discount of 13%.
- 96% of the 6% of residential customers paying unconditional prices more than 25% above the default offers have conditional discounts in 2023. This equates to about 290,000 customers with a customer-weighted average conditional discount of 29%.

Figure 3.8 Higher priced plans have large conditional discounts

Proportion of residential customers on plans with conditional discounts and customer-weighted average conditional discount by percentage above the DMO/VDO in 2023



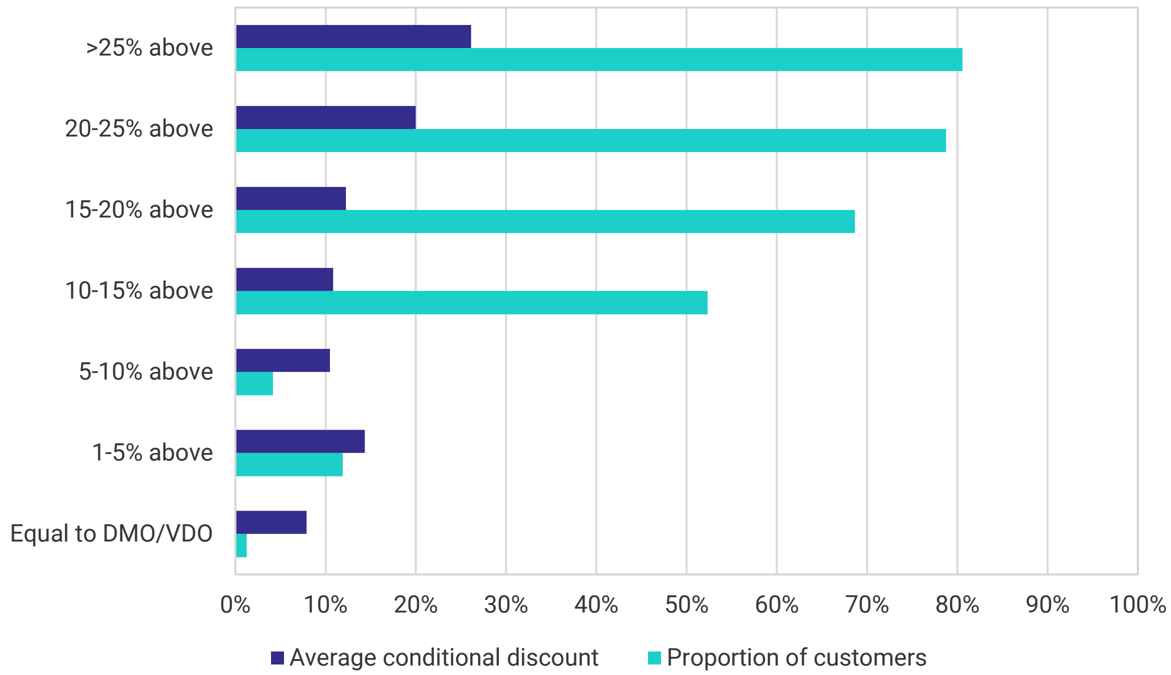
Source: ACCC analysis of retailers' data.

We saw a similar trend for small business customers, with discounts increasing as underlying prices increased. However, the proportion of customers both receiving a conditional discount and paying high prices was lower.

For instance, 81% of the 1% of small business customers paying unconditional prices that are more than 25% above the default offers had a conditional discount in 2023. This equates to around 4,400 small business customers in our sample. For this group of customers, we can see that even if conditional discounts are achieved, many customers would merely achieve prices equivalent to or above the default offers, particularly for customers on offers at 10–15% above the default offers and higher.

Figure 3.9 We observe a similar trend for small business customers

Proportion of small business customers on plans with conditional discounts and customer-weighted average conditional discount by percentage above the DMO/VDO in 2023



Source: ACCC analysis of retailers' data.

This raises concerns about whether the relationship between risk and reward in these legacy offers is evenly balanced and suggests customers would benefit from new plans.

In our June 2023 report, we found that, as at 1 July 2022, 9% of residential customers and 15% of small business customers failed to achieve their conditional discounts (of the 20% of customers who receive a conditional discount). The results for customers in the hardship and payment plan customer groups were more concerning, with 24% of hardship only customers and 24% of payment plan only customers failing to achieve their conditional discounts (of the 5% of hardship only and 11% of payment plan only customers who receive a conditional discount). These results suggest that some hardship and payment plan customers are not on the most appropriate plans for their circumstances.

Box 3.2 Financial impact of failing to achieve a conditional discount

For customers on plans with significant conditional discounts, whether or not those conditions are achieved can have a material impact on their annual electricity costs.

Using a residential customer on a flat rate tariff in the Endeavour Energy distribution region as an example, we can assess the extent to which a customer is penalised for not meeting a significant conditional discount. Using the Default Market Offer's model annual usage assumptions, a customer on an offer with a 20% conditional discount that is priced 25% above the Default Market Offer would pay an annual price of $2,228 provided they met the relevant conditions in each period (for example, payment of an electricity bill by a certain date to achieve a pay-on-time conditional discount).

However, if the customer was not to meet the relevant conditions on the 25% conditional discount, they would pay a significantly higher price on their electricity bill, especially in instances where the conditions were frequently not met. Assuming that a customer pays for electricity on a quarterly basis, we can assess the differences in price outcomes if a conditional discount is not met:

Conditional discount achievement frequency	Annual price	Penalty
100%	$2228	$0
75%	$2367.25	$139.25
50%	$2506.50	$278.50
25%	$2645.75	$417.75
0%	$2785	$557

The above table shows that failure to meet conditional discounts can result in a significant financial penalty, in addition to any late payment fees which may apply.

In 2018, the ACCC raised concerns with retailers' confusing discounting practices. At that time, 66% of residential customers received a conditional discount, while 27% of residential customers and 58% of hardship customers failed to achieve their conditional discount. The ACCC subsequently recommended that conditional discounts be restricted to the reasonable savings to the retailer of the condition being met.[66]

In response to these findings, conditional discounts attracted further regulation (see Box 3.3).

66 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry Final Report*, pp xii–xiii.

Box 3.3 Regulation of conditional discounts

Between 2018 and 2020, the following regulation was introduced to address conditional discounts:

- The Electricity Retail Code prohibits advertising conditional discounts as the headline price-related item, requires conditions to be clearly & conspicuously stated, and requires the conditional price and unconditional price to be compared to the reference price.
- The National Energy Retail Rules now state:
  - conditional discounts must not exceed a reasonable estimate of the costs incurred, or likely to be incurred, by the retailer resulting from the customer's failure to satisfy the relevant payment condition
  - market retail contracts cannot include conditional discounts where customers would definitely be worse off under the undiscounted market offer than under an equivalent standing offer.
- In Victoria, similar changes were introduced:
  - retailers must advertise offers with reference to the Victorian Default Offer
  - pay-on-time discounts are capped at a level set by the Essential Services Commission of Victoria (currently 7.16%) and must be honoured for customers receiving financial assistance.

In our August 2019 report, following the introduction of the Electricity Retail Code, we observed that retailers had undertaken 'a shift away from the use of conditional discounts…to instead advertise offers with eligibility criteria'.[67]

The ACCC is not concerned about conditional discounts which appropriately and efficiently allocate risk between consumers and retailers. Conditional discounts which reflect reasonable costs to the retailer of the consumer failing to meet a payment condition meet this criterion. When applied in this way, conditional discounts ensure all customers benefit, as the costs of late payment are not distributed across all customers.

A review of acquisition offers in Energy Made Easy and Victorian Energy Compare reveals that very few retailers (less than 5) currently offer pay-on-time conditional discounts, and the level of discount is considerably lower (1–5%). These lower conditional discounts reflect the successful impact of regulation on contracts that post-date regulatory changes.

We continue to observe that retailers offer lower priced products which require the customer to sign up through a particular method or pay by direct debit or automatic card payment, as an alternative to applying a conditional discount. As in 2019, the ACCC considers that 'changes by retailers that increase the transparency and certainty of prices that customers are likely to face when signing up to an electricity plan are a positive step.'[68]

In our June 2023 report, we found that the proportion of residential customers receiving a conditional discount had declined from 66% in the third quarter of 2018 to 20% in the third quarter of 2022.[69]

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67 ACCC, *Inquiry into the National Electricity Market: August 2019 report*, ACCC, Australian Government, p 63.

68 ACCC, *Inquiry into the National Electricity Market: August 2019 report*, p 63.

69 ACCC, *Inquiry into the National Electricity Market: June 2023 report*, Appendix E: Data appendix [data set].

However, as shown in Figures 3.8 and 3.9 above, a large number of customers continue to be on plans with large conditional discounts. When the Australian Energy Market Commission and Essential Services Commission of Victoria introduced restrictions on the size of pay-on-time conditional discounts (see Box 3.3), the new rules were only applied prospectively to new contracts entered into from 1 July 2020,[70] as:

- the Essential Services Commission of Victoria considered that if they applied the pay-on-time discount cap to all existing contracts 'it would likely result in retailers reducing the size of pay-on-time discounts that customers are currently receiving, so customers on existing contracts could end up paying more'[71]
- the Australian Energy Market Commission considered that:
  - exposure and experience to the risks and rewards of conditional discounts means that consumers on existing contracts with conditional discounts are more likely to be able to make an informed decision
  - the introduction of the Default Market Offer would improve comparability of plans making it unlikely that engaged consumers would stay on plans with conditional discounts
  - strengthened hardship guidelines from October 2019 mean that 'existing consumers that frequently miss conditional discounts and are in hardship should be moved onto more appropriate tariffs by their retailers'.[72]

As the rules took effect from 1 July 2020, this suggests that customers in our sample with large conditional discounts have not changed plan or provider in the last 3 years, if not longer.

The ACCC is concerned about the continued presence of plans with high conditional discounts and high underlying prices, compared to other offers in the market. In many ways the same concerns identified by the Australian Energy Market Commission regarding conditional discounts remain:

> … many consumers have not been well-placed to meet contract conditions, and that an imbalance in risk allocation between parties exists. Where risk allocation between retailers and consumers is no longer balanced or efficient, targeted restrictions on the level of conditional contract terms may be appropriate. Where such a restriction is set at reasonable costs, this approach would not unduly limit retailers' pricing freedom, while also providing a degree of protection for consumers.[73]

We consider that given the current cost of living pressures that Australians are facing, large conditional discounts which are beyond reasonable costs unnecessarily expose customers to the risk of higher prices. Our analysis shows that better offers are available for customers on plans with high underlying prices and high conditional discounts. For the customers in our sample, better offers include both the default offers as well as competitive acquisition

70 AEMC, *National Energy Retail Amendment (Regulating Conditional Discounting) Rule: Final determination*, AEMC, Australian Government; ESC, *Ensuring energy contracts are clear and fair: Final decision*, ESC, Victorian Government, 2020, p 55.

71 Essential Services Commission, *Ensuring energy contracts are clear and fair: Final decision*, p 56.

72 AEMC, *National Energy Retail Amendment (Regulating Conditional Discounting) Rule: Final determination*, pp 32–33. We note that the obligation in the AER Customer Hardship Policy Guideline is for retailers to include the following standardised statement in their hardship policy:

> When you join our hardship program, we will talk to you about your energy use and whether you are on the right plan. If we think there is a better energy plan for you, we will:
>
> - explain why the plan is better!
> - ask if you'd like to transfer to the new plan for free.

73 AEMC, *National Energy Retail Amendment (Regulating Conditional Discounting) Rule: Final determination*, p 11.

offers, and neither carry the same imbalance of risk allocation, either because there is no conditional discount attached or because the conditional discount reflects reasonable costs and is around 1–5%.

Conditional discount regulation has been effective, but the combination of consumer disengagement and the exclusion of legacy contracts from regulation, has allowed conditional discounts to persist.

3.5. Customers can save by switching, but barriers endure

Our analysis indicates that there remain incentives for customers to actively engage in the market and achieve savings by switching their electricity plan. This is supported by analysis of our pricing dataset and publicly available data from independent government comparison websites, Energy Made Easy and Victorian Energy Compare.

3.5.1. Comparing acquisition offers to the Default Market Offer and Victorian Default Offer

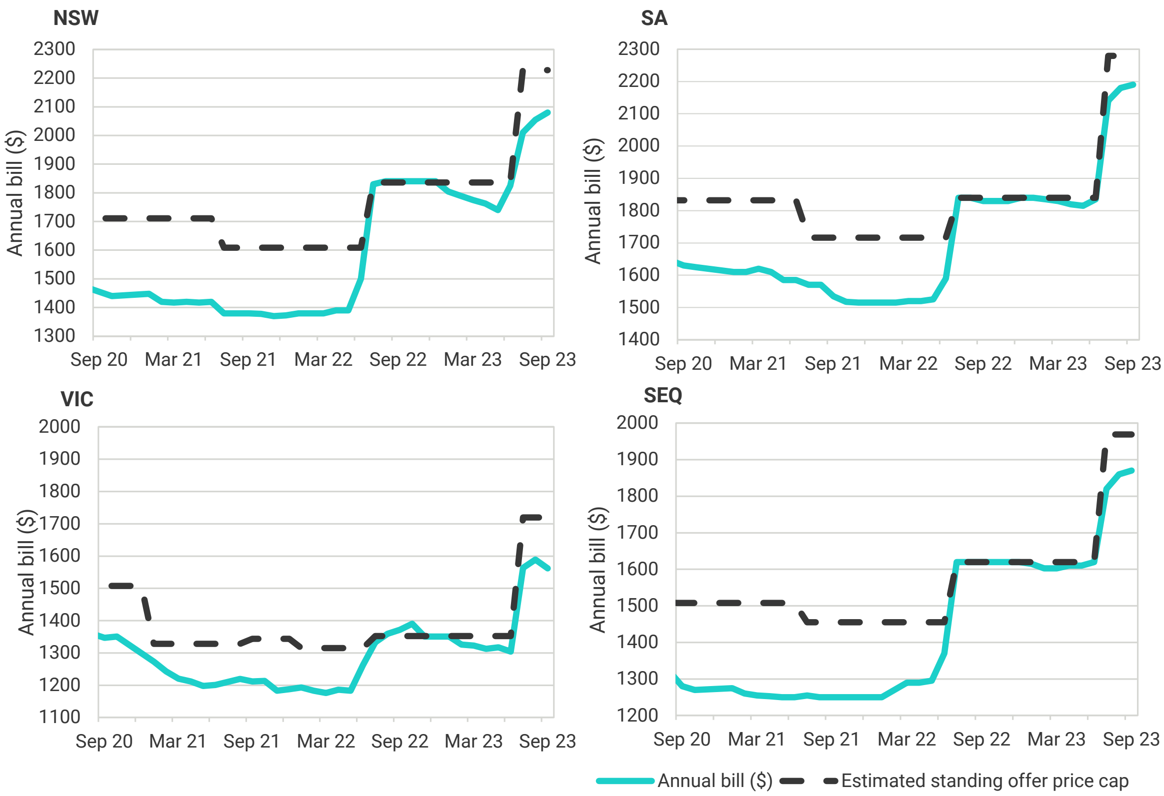
Figure 3.10 below shows median bills for offers on Energy Made Easy and Victorian Energy Compare as compared to the Default Market Offer and Victorian Default Offer between September 2020 and September 2023. Offers available in Energy Made Easy and Victorian Energy Compare are those that are generally available to new customers or switching customers and can be otherwise considered as 'acquisition' offers.

Figure 3.10 shows acquisition offers were offered at a discount to the default offer between September 2020 and June 2022, when acquisition offer prices converged with the standing offer price cap for much of 2022–23 due to the June 2022 energy market events. We also saw a number of retailers withdraw their acquisition offers in June 2022, and withhold offers for several months following the June 2022 energy market events.[74]

[74] ACCC, *Inquiry into the National Electricity Market: November 2022 report*, pp 87–88.

Figure 3.10 Acquisition prices are generally below the price cap on standing offers

Estimated median annual bill, residential flat rate market offers ($, nominal), September 2020 to September 2023



Source: ACCC analysis on Energy Made Easy and Victorian Energy Compare market offers dataset.

Note: The ACCC has not obtained reliable data for November 2020 and December 2020, and as such the observations in each chart for these periods were modelled based on data before or after that period.

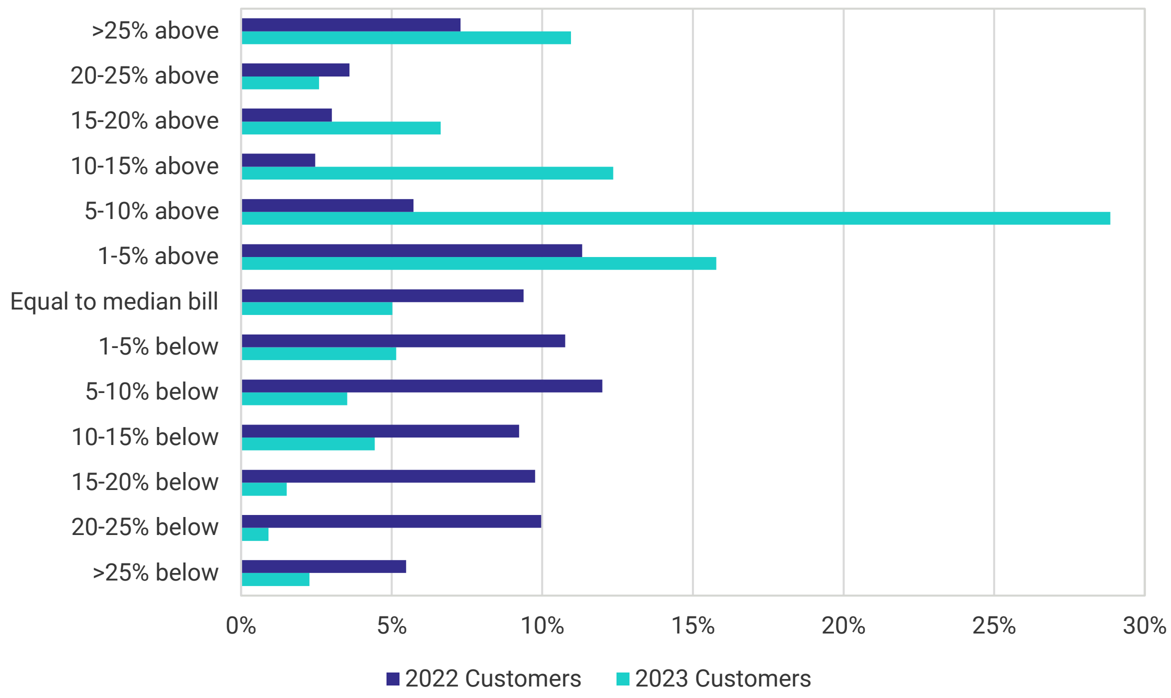
Note: Assumed annual usage in Ausgrid is 3,900 kWh, in Endeavour is 4,900 kWh, in Essential is 4,600 kWh, in Energex is 4,600 kWh, in South Australian Power Network is 4,000 kWh, in all Victorian distribution zones is 4,000 kWh. For states containing multiple distribution regions, the median annual bill is the median of relevant offers in the state, while the standing offer displayed is the median of the default offer prices from the relevant distribution regions.

Whilst median bills for offers on Energy Made Easy and Victorian Energy Compare have increased, the gap between estimated median bills and the standing offer price cap has been somewhat restored to previous levels since the July 2023 increase in the default offer. This indicates the retailers are actively competing for new customers and are able to offer acquisition offers at prices below the default offer.

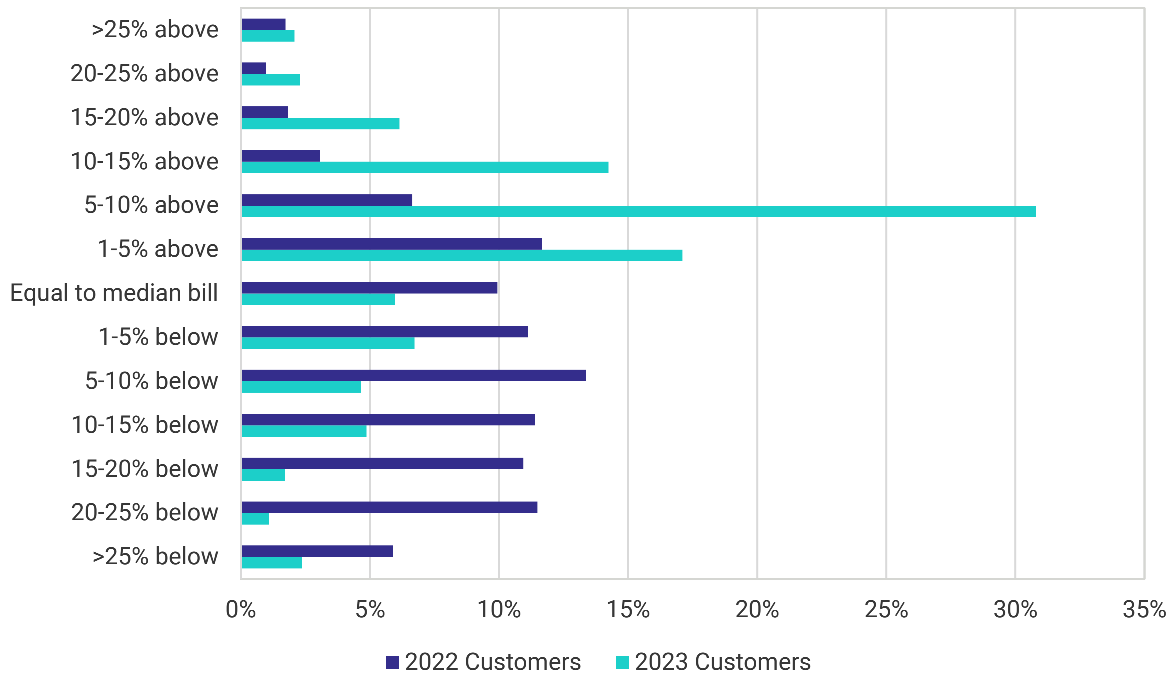
Further, when we compare acquisition offers on Energy Made Easy and Victorian Energy Compare against the prices we collected, we see that a large and increasing share of customers could make substantial savings if they were to switch (Figure 3.11 below).

Figure 3.11 Customers could save by switching

Proportion of residential customers on flat rate and flat rate with controlled load market offer plans paying more, equal to, or less than the EME/VEC median bill, assuming conditional discounts are not achieved



Proportion of residential customers on flat rate and flat rate with controlled load market offer plans paying more, equal to, or less than the EME/VEC median bill, assuming 100% achievement of conditional discounts



Source: ACCC analysis of retailers' data and Energy Made Easy and Victorian Energy Compare market offers dataset.

In 2023, 82% of residential customers were on calculated annual prices at or above the median offer on Energy Made Easy and Victorian Energy Compare, up from 43% in 2022.[75] This indicates that retailers price their existing customers differently to how they price their acquisition offers, and that there is a significant group of customers on existing plans that could save from engaging in the market and switching to a new offer.

Our analysis also indicates that in 2023, 59% of residential customers were on calculated annual prices that are higher than 75% of the offers available on Energy Made Easy and Victorian Energy Compare. The percentage of customers who could save by switching reduces to 53% once 100% achievement of conditional discounts is assumed. This indicates that savings are available to a large portion of customers if they are able to engage in the market and take advantage of an acquisition offer.

As part of collecting retail electricity prices, we asked retailers for information about how they set prices for their existing customer base as opposed to setting prices to acquire new customers. Our review of their responses indicates:

- retailers closely monitor their competitors' prices when setting prices for both acquisition offers and existing customers
- retailers may decide to make offers which are loss-leading or below target margins when competing for new customers
- pricing approaches aim to ensure a positive customer lifetime value, through future price movements, product design (for example, payment method or bill requirements) and targeting higher value customers
- retailers use the cost inputs to the Victorian Default Offer and Default Market Offer determinations for benchmarking and price setting purposes
- retailers use the Victorian Default Offer and Default Market Offer as a price ceiling for competitive acquisition offers, but not for prices for existing customers.

The use of the default offer determinations by retailers confirms that the provision of a common benchmark through a regulated price has changed retailer pricing in the market.

3.5.2. Customers on newer plans are paying less than customers on older plans

Further analysis of our new pricing dataset sheds light on the different price outcomes for customers who switched recently compared to more loyal customers. As outlined at the beginning of this chapter, we collected retail prices of all flat rate and flat rate with controlled load residential plans and of all flat rate small business plans with customers as at 1 August 2022 and 1 August 2023.

By comparing the pricing outcomes of customers on plans that existed as at 1 August 2022 and 1 August 2023 (**Older Plans**) to the outcomes of customers on plans that have only existed since 1 August 2023 (**Newer Plans**), we can draw further conclusions about retailers' approaches to price differentiation.

[75] When 100% achievement of conditional discounts is assumed, 79% of customers in 2023 are at or above the median offer on Energy Made Easy and Victorian Energy Compare, compared to 36% in 2022.

We note that this approach does have some limitations, as the age of a plan does not necessarily correlate with customer tenure. For example:

- customers on Older Plans may have been on the same contract and plan for a number of years prior to 2022
- new customers may have selected an Older Plan between 2022 and 2023 if it was still being marketed and advertised
- customers on Newer Plans may have been on the same contract with the same retailer for a longer period of time but were rolled over onto a new plan between 2022 and 2023.

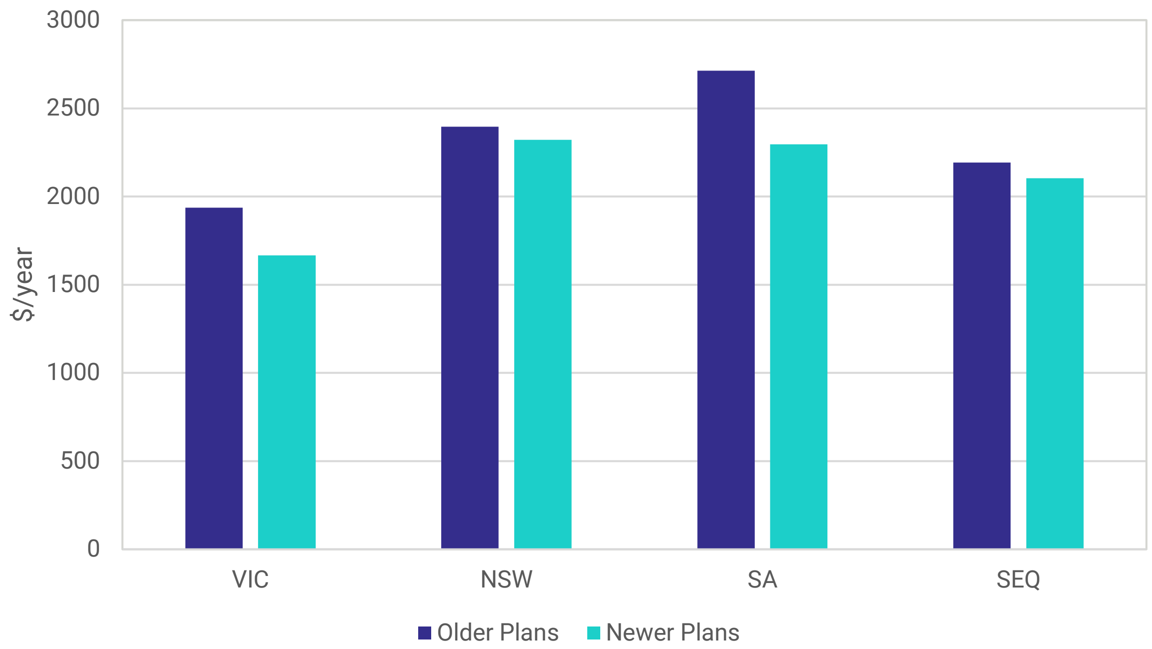
Approximately 70% of customers in 2023 are on Older Plans, compared to 30% of customers on Newer Plans.

Figure 3.12 examines the differences in customer weighted average annual prices between customers on Older Plans and Newer Plans. In all states, customers on Older Plans are paying higher average prices than those on Newer Plans, supporting the finding that:

- customers may achieve better price outcomes if they switch regularly
- customers need to continually re-engage in the market to obtain the benefits of competition
- customers who have not switched are more likely to pay higher prices.

Figure 3.12 Customers on older plans pay more than customers on newer plans

Customer-weighted average price for residential customers on plans which existed in 2022 and 2023 (Older Plans) and on plans which only existed in 2023 (Newer Plans) by state



Source: ACCC analysis of retailers' data.

Note: See Appendix C for a version of this figure inclusive of conditional discounts.

While the price gap is not overly large, it remains significant given the withdrawal of competitive acquisition offers from the market in 2022-23.

As noted above, a number of customers on Older Plans may have been on the same plan for a number of years prior to 2022. We can see that the pricing outcomes of this customer cohort are worse than those on Newer Plans, indicating that customers are being penalised if they have not recently switched plan or retailer.

Box 3.4 Your retailer must tell you if you could be on a better offer

Retailers across the NEM must undertake a better offer check and include a better offer message regularly on customers' electricity bills. This message lets customers know if they could access a better offer from their existing retailer.

This requirement aims to give consumers clear, timely, and transparent information about electricity offers to engage confidently in the market.

However, consumers still need to act in response to these messages. In September 2023, the Essential Services Commission of Victoria found that only 1 in 2 Victorian residential electricity consumers were on their retailer's best offer in 2022–2023.[76]

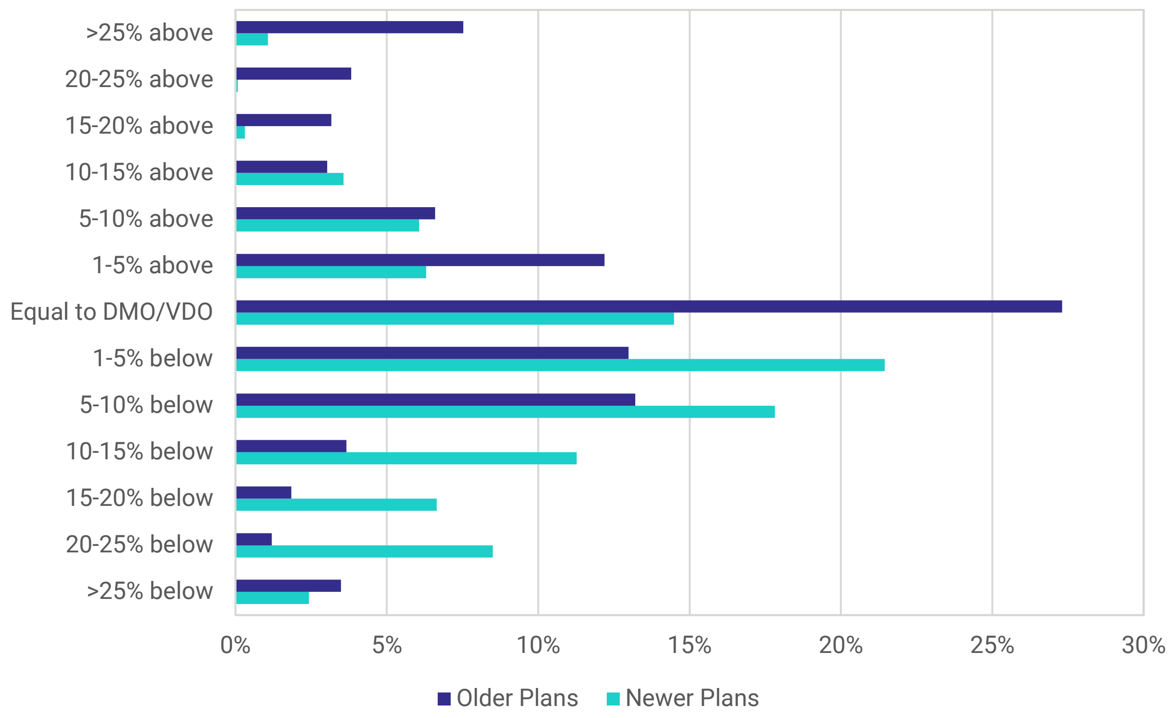
We can also see how longstanding customers are disadvantaged by examining the distribution of Older Plans and Newer Plans compared to the Default Market Offer and Victorian Default Offer.

Figure 3.13 shows that a significantly greater proportion of residential customers on Older Plans are paying prices equal to or above the default offers in 2023 compared to newer plans. Approximately 64% of customers on Older Plans are paying a calculated annual cost equal to or above the equivalent default offer price, as opposed to only 32% of customers on Newer Plans. When we assume conditional discounts are achieved 100% of the time, 31% of customers on Newer Plans are paying a calculated annual cost equal to or above the equivalent default offer price, whereas for customers on Older Plans the percentage drops to 54%.

76 ESC, Victorian Energy Market Report: September 2023, ESC, Victorian Government, pp 6-8.

Figure 3.13 More customers on Older Plans are paying prices equal to or above the Default Market Offer and Victorian Default Offer

Proportion of residential customers by discount to the DMO/VDO, plans which existed in 2022 and 2023 (Older Plans) and on plans which only existed in 2023 (Newer Plans) excluding conditional discounts



Source: ACCC analysis of retailers' data.

Note: See Appendix C for a version of this figure inclusive of conditional discounts.

Together with our other findings on conditional discounts and acquisition offers, we see that:

- retailers continue to compete for new customers by offering acquisition offers at a discount to the default offer
- retailers are not competing as hard to retain existing customers, although they do assess customer churn risk when setting prices
- there is a large cohort of customers who have not recently switched retailer or plan on prices above the default offer, who are being charged a 'loyalty penalty'.

Due to the limitations of plan date information in our dataset, we are unable to examine the full effect of customer tenure on pricing. However, our analysis above suggests that the pricing outcomes of longer-tenured customers would be worse than those who actively engage in the market and regularly switch.

3.6. Reducing uncertainty and complexity to improve consumer outcomes and conditions for competition

Our new data set has been crucial in helping us to trace how market structure and retail pricing practices shape consumer outcomes in the retail electricity market.

Electricity consumers are a diverse population and engage with the retail electricity market in different ways. They fall on a wide spectrum between consumers who are actively engaged, regularly seek out better deals, and feel confident dealing with their electricity retailer, and consumers who do not or are not able to engage.

Many consumers can find navigating the electricity market difficult, from comparing prices and tariffs, to understanding how and why their electricity prices have changed at short notice.

The flat rate market offer plans analysed in this chapter represent simple and traditional energy products which many consumers have experience with. As we increase residential electrification, consumers will be asked to understand and compare more complex energy products and choose the best product for them. Designing a market which facilitates consumer choice and efficient outcomes for consumers while also ensuring there is appropriate regulation in place to protect consumers is a finely balanced task.

Since their introduction in 2019, the Default Market Offer and Victorian Default Offer have delivered tangible benefits to consumers, fulfilling a dual purpose in capping the prices of plans for a small number of customers and acting as a common reference price for the majority of offers and customers. The price caps have significantly reduced prices paid by customers on standing offers. The requirement to compare offers to the Default Market Offer and Victorian Default Offer has increased retail price transparency, improved offer comparability, and consigned confusing discount advertising to the past.

Similarly, the introduction of further restrictions on conditional discounts through the Electricity Retail Code, the National Energy Retail Rules and the Victorian Energy Retail Code of Practice has dramatically reduced the size and prevalence of conditional discounts, increasing the comparability of offers.

However, as the market continues to evolve, market bodies and state and federal governments should ensure that our regulatory framework remains effective in supporting meaningful consumer engagement and providing the necessary levels of consumer protection, whilst also ensuring the conditions for competition are maintained.

Giving consumers price certainty and addressing legacy plans with large conditional discounts

For many consumers, choosing an electricity provider and product is a ‘set and forget’ task, which means retailers compete at the point of acquisition, but are not incentivised to keep prices for existing customers competitive. As set out in section 3.5, we found that consumers who do not regularly engage in the market experience higher prices.

This is the case for a significant number of customers who remain on plans with large conditional discounts and high underlying prices. This is despite the introduction of further restrictions on conditional discounts in 2020 by the Australian Energy Market Commission and the Essential Services Commission of Victoria, which were not applied to existing contracts (as discussed in section 3.4) and only applied to new contracts entered into after the commencement of the new rules.

When consumers do engage with the market, it is not uncommon for their prices to increase not long after they sign up to a new plan. Under the National Energy Retail Law and Rules, retailers are able to offer ongoing market retail contracts and increase prices at any time with at least 5 days' notice to consumers.

This type of conduct increases perceived switching costs for consumers and may reduce consumer confidence in the market. Our analysis suggests that retailers recoup their costs over a customer's lifetime, by setting attractively low acquisition offers and making subsequent unilateral price increases for their existing customer base over time. The accrual of these price increases over time explains why so many customers are on market offer plans at or above the default offers, especially if they are not price sensitive, or more concerningly, face barriers to engaging in the market (for instance, literacy or language barriers) and have not changed plans.

Recommendation 1

Policy makers should investigate how best to reduce the number of customers on legacy plans with large conditional discounts, as a matter of priority.

Other areas of investigation should include:

- the impact of evergreen or ongoing contracts on consumer behaviour
- whether current rules around price changes reduce price certainty and contribute to the switching burden.

Strengthening protections for consumers experiencing vulnerability

While governments have invested significant resources in concession and rebate programs and have undertaken extensive research and analysis to improve consumer outcomes, there are systemic challenges in supporting consumers experiencing vulnerability.

Approximately 25% of customers in our data set were identified by retailers as concession customers. The price outcomes for concession customers are broadly similar to the outcomes for all residential customers, with 42–49% of concession customers on offers at or above the default offers (depending on whether we assumed achievement of conditional discounts or not) in our sample.

The proportion of concession customers on high priced market offers in our sample suggests their underlying offers may not be well aligned with their ability to pay and may be dampening the impact of government support.

The ACCC supports the proposed reforms outlined in the Australian Energy Regulator's Game Changer Report to energy ministers which would require retailers to automatically move financial hardship customers onto better energy retail offers and upgrade concession and rebate systems to improve the portability of entitlements.

We will examine the impact of rebates on billing outcomes in our next report in 2024.

Extending price protection to embedded network customers of authorised retailers

If retail customers are receiving prices above the Default Market Offer in a competitive market, we hold concerns for embedded network customers who do not have the benefit of competition or regulated pricing.

Victorian embedded network customers and embedded network customers of exempt sellers already receive the benefit of price protection.

We previously recommended and supported extending the Default Market Offer to embedded network customers in the Department of Climate Change, Energy, the Environment and Water's review of the Electricity Retail Code which commenced in 2021.

We will examine bill outcomes for embedded network customers for the first time in our next report in 2024.

Ensuring consumers remain protected and are supported to engage in the market

Electricity markets must be regulated in a way that promotes consumer confidence, including by acknowledging where competition is delivering outcomes for consumers and where targeted support is needed.

Our analysis shows that there are a large proportion of disengaged customers on high priced market offer plans in our sample. In some instances, these customers may be better off on a regulated standing offer, given the higher level of consumer protections standing offers provide (see section 2.5). Although acquisition offers are priced at a discount to the default offers, our analysis suggests that, as market offer plans are subject to price increases that accrue over time, customers can find themselves on a plan that may have started out as good value but no longer compares well to the default offers. If customers are willing to continually re-engage in the market, this is not problematic. However, we are concerned that customers who are unwilling or unable to engage or re-engage in the market, may be better off taking up a standing offer with prices set independently by a regulator.

There is a current requirement in the Electricity Retail Code for retailers to compare new prices to the reference price (being the Default Market Offer). However, retailers in New South Wales, South East Queensland and South Australia are not required to tell consumers that they could access the Default Market Offer in the form of their retailer's standing offer.

In Victoria, retailers are required to include the following message on electricity bills:

> The Victorian Default Offer is a reasonably priced electricity offer set by Victoria's independent regulator. Contact us on [phone number] to discuss the suitability of this plan for you.[77]

The ACCC has previously recommended introducing a positive obligation on retailers to disclose a customer's entitlement to the standing offer on price change notices when communicating new prices that are higher than the Default Market Offer, as part of the Department of Climate Change, Energy, the Environment and Water's review of the Electricity Retail Code which commenced in 2021. If a customer is prompted to enquire about the Default Market Offer after seeing the message on their price change notice, their retailer can help the customer decide if the standing offer, or another market offer, is most suitable for them.

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77 Energy Retail Code of Practice (Vic) cl 63(1)(bb).

This brings into focus the dual purpose of the Default Market Offer as a mechanism to both protect consumers and maintain incentives for competition in New South Wales, South East Queensland, and South Australia.

As set out in Box 3.4, retailers are required to regularly tell customers if there is a better energy plan available on their electricity bills. This requirement took effect in jurisdictions which have adopted the National Energy Retail Law and Rules in September 2023, and is intended to prompt consumer engagement.

The Default Market Offer is set with the following objectives as guiding principles:

- reduce unjustifiably high standing offer prices and continue to protect consumers from unreasonable prices
- allow retailers to recover the efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention
- maintain incentives for competition, innovation and investment by retailers, and incentives for consumers to engage in the market.[78]

A holistic review of the Electricity Retail Code, scheduled to commence in November 2024, offers one vehicle for considering whether the current communication requirements and the settings for the Default Market Offer are correctly calibrated.

For instance, time-of-use small business plans and plans with demand charges are currently excluded from the application of the Default Market Offer. Given the roll out of smart meters and incentives for retailers to replicate network tariff structures in retail electricity prices, more customers are likely to be offered time-of-use plans and plans with demand charges by retailers. This also means that consumers on standing offers are becoming more likely to be on a plan with a demand charge and may be exposed to unreasonably high prices.

Recommendation 2

The next review of the Electricity Retail Code to be undertaken by the Department of Climate Change, Energy, the Environment and Water is scheduled to commence in November 2024.

Areas of focus should include:

- consumer disengagement and barriers to consumer engagement
- the increasing complexity of retail tariff structures
- interactions with other reforms made after the communication requirements in the Electricity Retail Code were introduced, such as the Australian Energy Regulator's Better Bills Guideline.

78 AER, *Default market offer prices 2023–24: Final determination*, p 2.

4. Contract market outcomes

Key Points

- Electricity hedging contract prices have moderated since mid-2022, although they have not returned to pre-2022 levels.
- Trading activity has remained subdued across most regions since mid-2022, with volumes traded generally either at or below levels in recent years. Almost half of generators and gentailers (vertically integrated market participants that have generation and retail arms of their business) surveyed reported a change in their approach to selling or offering hedging contracts in the period after August 2022, with more sales decreasing than increasing. Decreasing sales could represent a decreased tolerance for spot market exposure since the volatility seen in mid-2022 and generators seeking to sell fewer contracts.
- Market participants are still reliant on traditional hedging products (swaps and caps), with flat swaps making up the majority of traded volume from August 2022 to July 2023.
- Trades of newer products, more suited to a market with increased variable renewable energy generation, are still rare. Examples include weather derivatives, insurance-like products, and products shaped to a particular time of day.
- Trading of caps with strike prices above $300/MWh emerged in 2022 when spot-market prices were very high, however, trades of these products have declined slightly since then.
- Small retailers typically hedge over shorter and more varied time horizons than larger generators and gentailers. Contracting over shorter time horizons increases retailers' exposure to spot market conditions. In some cases, this may be intentional and reflect different risk preferences of retailers. However, contracting over shorter time horizons could also reflect the financial challenge of managing margin and collateral requirements, as hedging further in advance requires entering into more contracts simultaneously.

4.1. A competitive contract market is critical to facilitate effective risk management

This chapter examines the electricity hedging contract market in terms of its role and observations of recent market dynamics, including prices and trading behaviour.

This is the second time the ACCC has reported on the electricity contract market. We first did so in November 2022, in response to concerns about the impact of changes in the contract market following the energy market volatility events of mid-2022 that culminated in the suspension of the National Electricity Market (NEM) in June 2022.

In that report, we recommended that the Australian Energy Regulator should have contract market monitoring powers as part of its wholesale market monitoring and reporting functions, including monitoring the over-the-counter (OTC) market.[79] We made a similar

[79] ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 6.

recommendation in our 2018 Retail Electricity Pricing Inquiry Final Report.[80] A Bill that will expand the Australian Energy Regulator 's functions in this manner is expected to be tabled in the South Australian Parliament in late 2023 or early 2024.

While most hedging contracts relating to the NEM are traded on the Australian Securities Exchange (ASX), a significant portion are traded directly between market participants. These arrangements are known as OTC trades. As OTC trades are settled privately, publicly available information cannot provide a full picture of the contract market.

Accordingly, we used our compulsory information gathering powers to obtain extensive trade data, including OTC trades, from a large sample of market participants. We also collected qualitative information related to market participants' opinions, experience, and hedging practices in the electricity contract market. Box 4.1provides further information on the nature of the information collected and reported on in this chapter.

Box 4.1 Market sample used for our analysis

Our dataset is comprised of information from 21 market participants, including both small, standalone retailers ('small retailers') and medium and large stand-alone generators and vertically-integrated retailers (termed 'large generators and gentailers' in Chapters 4 and 5).

We collected extensive qualitative data from these participants in form of a survey. This survey asked respondents to indicate how strongly they agreed with certain statements and how significant certain factors were, relating to potential issues in the contract market. The questions covered a range of topics including companies' experience complying with prudential and credit requirements, access to hedge contracts, internal company risk management and policies, and their views about the long-term future of the contract market. Use of a survey has allowed us uncover areas of general concern in the contract market, as told directly by market participants. These issues are predominantly discussed in Chapter 5.

The quantitative data gathered for this report is comprised of individual trades from market participants. This includes all exchange-traded and OTC contracts entered into by participants in our sample, traded between August 2022 and July 2023. Our dataset represents the vast majority of all the NEM hedging contracts traded in that period.

The data collected for each trade was comprehensive and includes price, volume, delivery period, contract category and counterparty information. Our analysis is primarily focused on contracts traded 'externally' with the market and not those traded 'internally' between related entities, or generation and retail arms of vertically-integrated companies.

This section commences by setting out the role of the contract market and other risk management strategies that can be utilised by market participants. The discussion that follows in this chapter and Chapter 5, sets out the key insights obtained from the information obtained by market participants using our compulsory information gathering powers, supported by relevant publicly available information.

80 ACCC, *Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry Final Report*, 15 November 2023, p xviii.

4.1.1. Role of the contract market and hedging

The contract market operates in parallel to the wholesale-electricity spot market. Prices on the spot market can vary enormously and are hard to predict. Electricity retailers and generators use hedging contracts to reduce their exposure to high (or low) wholesale spot prices. Contracts can be traded on the ASX, the Financial and Energy Exchange Global (FEX), or be negotiated between parties as OTC contracts.[81]

A hedging contract sets out the terms on which a generator will sell electricity to a retailer. The volume of electricity to be sold and the price per unit volume (known as the strike price) are usually specified among these terms. These arrangements are typically made for some period in the future. When that time arrives, the generator must sell electricity on the spot market, at the spot-market price, and the retailer must buy the electricity from the spot market at the same price. The hedging contract is settled by one party compensating the other such that the net amount paid by the retailer and the net amount received by the generator match the contract terms.

The liquidity of the contract market is reflected by the number of contracts being traded and the relative availability of those contracts to retailers. A liquid contract market allows risk to be effectively managed by both retailers and generators. This is important for maintaining market stability and competition, including the entry of new retailers and generators into the NEM.

For retailers, hedging contracts provide more certainty around the cost of wholesale electricity for a certain time period and allow retailers to then offer their customers prices that are less volatile than wholesale prices while charging a retail margin. Offering stable prices to customers is necessary for retailers to attract and retain customers and to meet regulatory obligations in some regions.[82]

For generators, the contract market provides a certainty of return and enables them to manage operational costs, such as maintenance and fuel. It also allows them to secure funding for investment when planning new generation assets.

Each retailer and generation business has a hedging strategy that sets out to what extent, and how, they intend to mitigate their exposure to spot-market risks. Hedging strategy refers to how a business uses hedging contracts to mitigate their exposure to wholesale market risk. A range of risks are commonly considered as a part of determining a hedging strategy, including price volatility, volume uncertainty (unpredictability in forecast load or generation dispatch) and the time of use load shape.

Each generator and retailer's hedging strategy depends on the liquidity of the contract market, the volatility in the spot market and the risk appetite of the business. This is reflected by the varying time periods covered by different contracts, and the variety and volume of hedging products chosen to cover the risk of the retailer's retail load or guarantee a return on generation assets.

81 Market participants ordinarily document OTC trades using the industry standard, International Swaps and Derivatives Association Master Agreement; ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 33.

82 ESC, Energy contract rules to ensure a fair deal, ESC, Victorian Government, 2023, accessed 20 October 2023.

4.1.2. Types of hedging contracts

Retailers commonly manage price, volume and shape risk using a variety of hedging products, informed by the company's risk management policy and hedging strategy. Common examples of hedging contract types and categories include:

- swap contracts, that specify the price per unit of electricity (the strike price) that the buyer will pay over some future period (for example, quarter 3, 2024)
- option contracts that provide a right to the holder to enter into a specified contract at some future time
- cap contracts that place a ceiling on the price a buyer will pay per unit of electricity over some future period.[83]

The amount of electrical energy or power specified in a hedging contract is important, as it determines how much the retailer's or generator's spot-market risk is reduced. In this report, we use 'volume' as a general term to describe either the amount of energy or power. Some examples of how volume can be specified (or not specified) in different categories of contracts include:

- Fixed-volume hedging contracts where the total amount of energy over the contract period is agreed in advance. The power output at certain times of the day or week may also be specified. In this report, we use the term 'firm' to describe contracts where the power output is specified in the contract and the term 'flat' to refer to contracts where the same power output and strike price apply at all times of the day or week. Flat swaps are the most common type of hedging contract in the NEM.
- Load-following contracts, where a fixed price is paid per unit of energy, but the volume is not agreed in advance. Instead, the volume of electricity that is settled under the hedging contract depends on (or 'follows') the load of the buyer of the hedging contract. These contracts provide the greatest reduction in risk for retailers as the volume risk is transferred to the generator.
- Generation-following contracts, where a fixed price is paid per unit of energy, but the volume is not agreed in advance. This is similar to a load-following contract, however, in this instance, the amount of electricity settled under the contract depends on (or 'follows') the power output of the seller of the contract. These contracts provide the greatest reduction in risk to the generator but transfer the volume risk to the retailer. A common example is a power purchase agreement, executed between a retailer and a renewable energy project.

When a generator (or retailer) offers a contract that exposes them to less risk than the other party, such as options, caps, and load-following-swaps, they charge a 'premium'. The premium is an additional amount of money that is incorporated into the contract as compensation for taking on the additional risk.

The increase in generation from renewable energy sources has seen the creation of new hedging contract products. Solar and wind plants cannot guarantee providing power when it is needed. They therefore cannot guarantee being able to honour a contract to supply power consistently and continuously at all times of the day, which is required under most traditional contract types, such as flat swaps. Emerging hedging products that better suit renewables

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83 AER, *State of the Energy Market 2023*, p 46.

include super-peak swap contracts, solar-shape swap contracts, inverse-solar-shape contracts, and virtual-storage contracts.[84]

As coal power plants retire in line with the energy transition, there will likely be a reduction in the number of generators that can offer flat swaps. Retailers' need for products that guarantee prices at all times of day is also likely to reduce, as typical spot prices during the middle of the day continue to drop with increased solar penetration. It is therefore likely that there will be a change to both the demand and supply of the traditional hedging products.

4.1.3. Participants can also use other forms of risk management

Retailers and generators can use alternative risk management strategies to complement or replace their use of hedging contracts. Examples include vertical integration, virtual power plants (VPP), demand response and spot-price pass-through.

In the context of the NEM, vertical integration is where a market participant owns 2 or more stages of the electricity supply chain – commonly generation and retail. Vertically-integrated companies are often referred to as gentailers. Gentailers have an 'internal hedge', where the loss faced from low wholesale spot prices is balanced by the retail arm of the business, which gains from low spot market prices. The same principle applies in reverse when wholesale spot prices are high. Historically, vertical integration has been typically confined to the larger players in the market because of the scale of generation assets. However, the decreasing economies of scale with newer generation technologies could provide the opportunity for smaller players to become vertically integrated. Examples of vertical integration solutions for small participants could include small-scale solar farms and community batteries.

VPP refers to when energy is pooled from a wide range of energy assets or generators that can be used to act like a single power plant from a centralised control system.[85] Examples of such assets are rooftop solar or batteries. Using software, generation or storage from multiple sources can be pooled and fed into the grid during times of generation shortfall. This is an emerging option that has been made possible by advances in technology that allow for remote monitoring and operation of a large number of distributed solar systems and batteries. A VPP can feed electricity into the grid during peak periods to mitigate the risk of high spot prices. VPPs are relatively new and are still in trial stages in many cases. Despite this, there are already many commercially available VPP products in the NEM, and they are expected to play an increasing role in retailer risk management in the future.[86]

Demand response is when end users of electricity voluntarily reduce their usage at times of high spot prices, which are caused by shortfalls in supply or during peak demand periods.[87] The retailer would typically motivate this behaviour by offering a financial reward. Most of Australia's largest retailers have demand response programs, although in some cases they are only available to business customers, who use enough electricity to make the demand response arrangement worthwhile.[88] In the future, technology advances could allow retailers

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84 Australian Renewable Energy Agency (ARENA), *Renewable Energy Hub Contract Performance Report*, ARENA, Australian Government, November 2020, accessed 22 October 2023.

85 ARENA, *Renewable Energy Hub Contract Performance Report*; ARENA, What are virtual power plants and why do they matter?, ARENA, Australian Government, 8 February 2021, accessed 22 October 2023.

86 G Kuiper, *What is the state of virtual power plants in Australia?*, Institute for Energy Economics and Financial Analysis (IEEFA), March 2022, accessed 22 October 2023.

87 ARENA, Demand response, ARENA, Australian Government, 1 August 2023, accessed 22 October 2023.

88 AGL, Demand response, AGL, n.d., accessed 22 October 2023; Energy Australia, About Power Response, Energy Australia, n.d., accessed 22 October 2023; Origin Energy, Demand Response, Origin Energy, n.d., accessed 22 October 2023.

to further capitalise on this by coordinating large numbers of residential consumers to reduce their demand at peak times.

Spot-price pass-through is a risk management strategy where retailers pass through the high and low spot prices to the end user of electricity. This transfers the wholesale price risk from the retailer to the consumer, meaning that the price the end-customer pays is highly variable. Despite the increased risk, some customers may opt for this arrangement as it allows them to save money if they are able to shift demand in response to spot market prices.

4.2. Recent market dynamics

Our trade data shows that contract prices have moderated since their peak in 2022. However, trade volumes remain subdued, possibly reflecting changes in participant risk appetite following the extreme spot prices and market suspension in mid-2022.

4.2.1. Contract prices have moderated since mid-2022

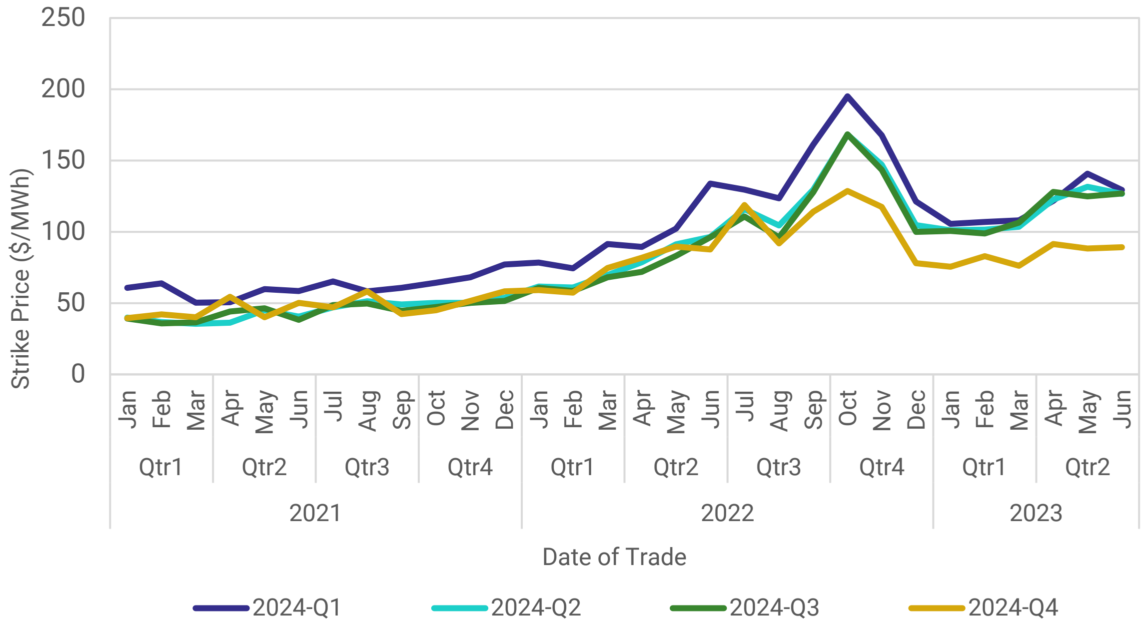
Two of the most traded hedging products are swap and cap contracts. Prices for swap and cap contracts have eased following the period of high and volatile prices in quarter 3 2022. However, they are still higher than the levels before this period. This is shown in Figure 4.1 and Figure 4.2.

Figure 4.1 shows the average strike price of swaps, including both ASX and OTC trades. Prices increased rapidly in mid-2022 and peaked in October 2022. This was a time of high and volatile spot prices, following the suspension of the market in June 2022. Prices then fell sharply in December 2022, around the time that coal and gas price caps were announced.[89] However, prices in December 2022 remained notably above the prices observed before the volatile price period in early 2022. Prices have been gradually increasing again since March 2023 but remain well below the October 2022 peak.

89 ACCC, Gas price cap, ACCC, Australian Government, 23 December 2022, accessed 22 October 2023.

Figure 4.1 Average swap strike prices have decreased since mid to late 2022, but have not returned to pre-2022 levels

Average strike price of swap contracts purchased from January 2021 to June 2023 with delivery periods in 2024

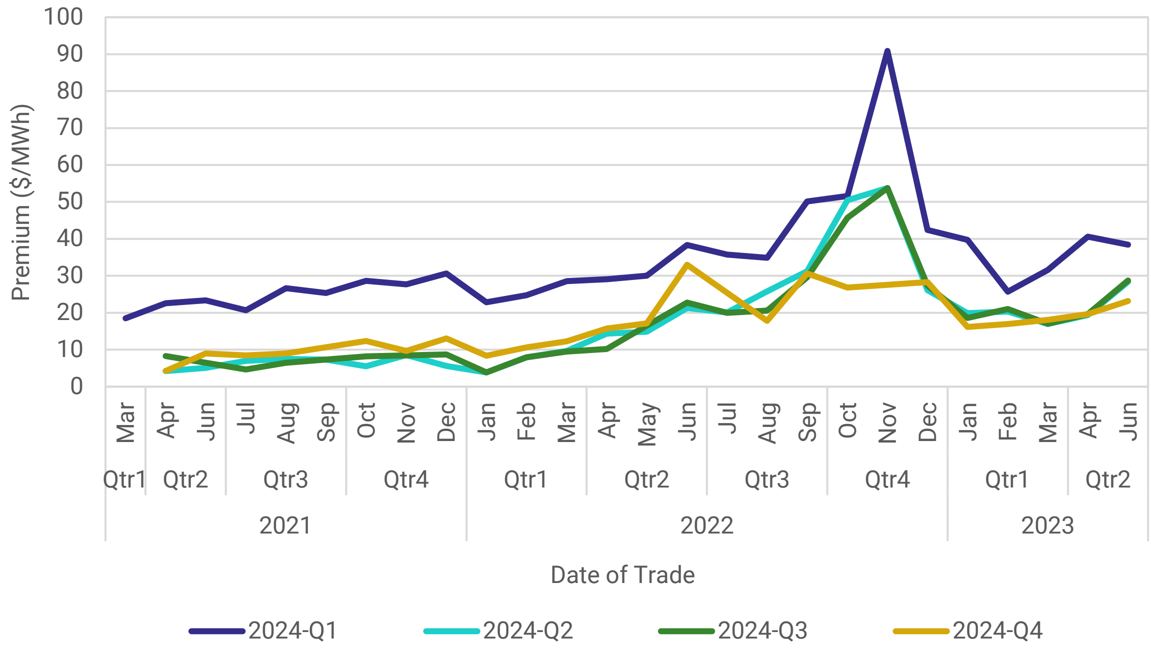


Source: ACCC analysis of hedging contracts data.

Figure 4.2 shows the average premium of cap contract prices for various forward periods in 2024, including both ASX and OTC trades. The trend for caps is similar to the trend for swaps, with prices spiking in the second half of 2022 and settling well above pre-2022 levels throughout 2023.

Figure 4.2 Average cap contract premiums have decreased since mid to late 2022, but have not returned to pre-2022 levels

Average premium price of cap contracts purchased from March 2021 to June 2023 with delivery periods in 2024



Source: ACCC analysis of hedging contracts data.

Note: Some months had outlier average prices, influenced by low trade volumes. Average prices for these months have not been included, as we do not consider them representative of the broader price trends. We have interpolated to provide an indicative price trend across these months.

We found no significant difference in the prices of ASX and OTC contracts when like-for-like products were compared.[90] There was also no significant difference observed in prices paid by small retailers and prices paid by large retailers when doing like-for-like comparisons on common contract types for equivalent periods.

4.2.2. Trading activity has remained subdued across most regions

Trading activity has remained subdued across most regions since mid-2022, with volumes generally either at or below levels in recent years in our dataset (see Figure 4.3).[91] This is consistent with the Australian Energy Regulator's 2023 State of the Energy Market report, which found that ASX traded volumes declined 13% over the 2022-23 financial year.[92]

Contract volumes in New South Wales, South Australia and Queensland showed noticeable declines in June 2023 when compared with the same month in 2021 and 2022. While volumes in Victoria remained relatively steady across all June periods.

90 Our November 2022 report found divergence between ASX and OTC prices in some periods. We believe that this finding was influenced by outlier contracts that were the result of option exercise, which made ASX prices appear lower than they really were during periods of high prices.

91 Our dataset includes trades includes January 2021 and July 2023.

92 AER, *State of the Energy Market 2023*, p 46.

Our results indicate that subdued volume is partly due to a change in generator and gentailer trading behaviour, with almost half of all generators and gentailers surveyed reporting a change in their approach to selling or offering hedging contracts in the period after August 2022. Most generators and gentailers indicated that they had decreased their contract sales, but some also indicated that they had increased their sales.

Of those generators who indicated a change in their trading behaviour, all reported that a change in risk-related policies was a key driver for this change. Decreasing sales could be a result of spot-market risk changing as the energy transition progresses. We discuss this issue in detail in Chapter 5.

When assessing their risk-management strategies, generators need to consider the likelihood of high spot-market prices and plant outages. Both these risk factors are increasing, as more renewable generation comes online, and the reliability of power plants reduces as they approach retirement. When spot-market prices are high, it is very costly for a generator to reduce its output (such as when a generating unit breaks down) if its full capacity has been contracted to a retailer. This is because it will have to compensate the retailer for the high prices in the spot market without receiving any revenue in return. Generators can mitigate this risk by contracting a smaller portion of their maximum capacity. The market volatility seen in 2022, which highlighted the changing risk environment, may have resulted in decreased tolerance for spot-market exposure and generators seeking to sell fewer contracts.

We expect this trend in changing trading behaviour to continue as coal plants age and near retirement, and generators and gentailers seek to mitigate the downside risks of their reducing plant reliability and output. We also expect generators and gentailers to change their trading behaviour as they replace coal plants with less predictable generation types that are not suited to more traditional flat contract shapes.

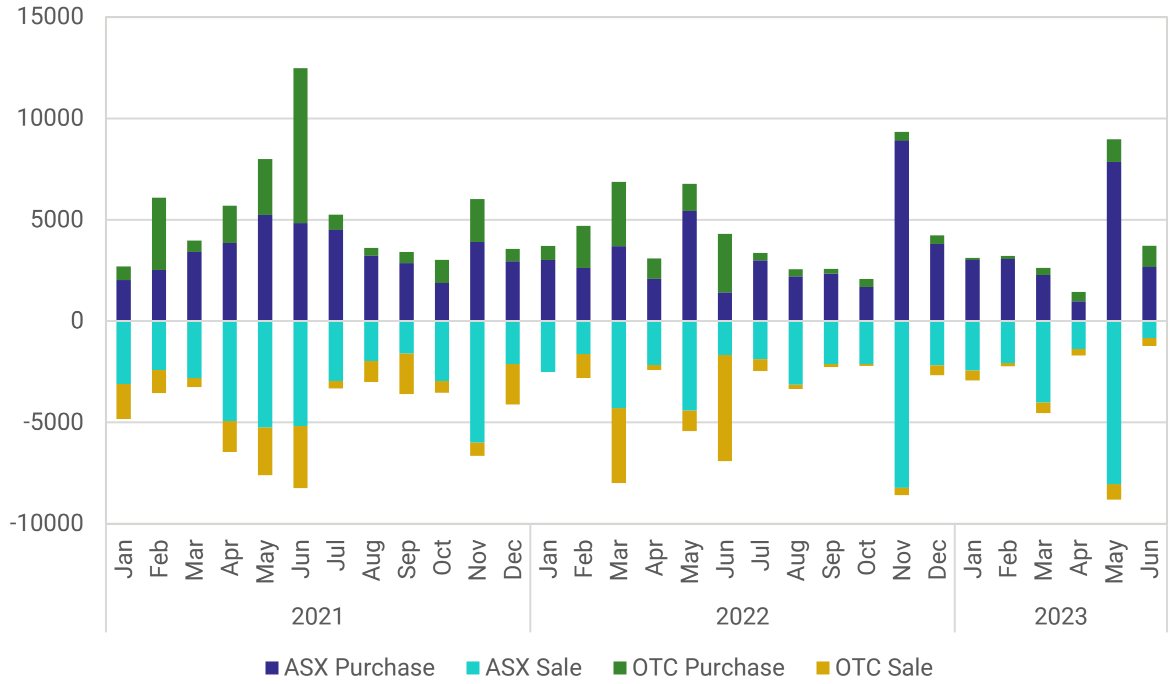
High trading activity in the months of May and November, as shown in Figure 4.3, can be explained by financial year and calendar year ASX options often being exercised in these months. For example, this type of trade accounts for at least half of all volume traded in our data in New South Wales and Queensland for November 2022.

Figure 4.3 shows the entire volume for each contract on the date it was traded, regardless of the time span covered by the contract. This means that long-term contracts spanning multiple years also contribute to apparent spikes in trading activity.

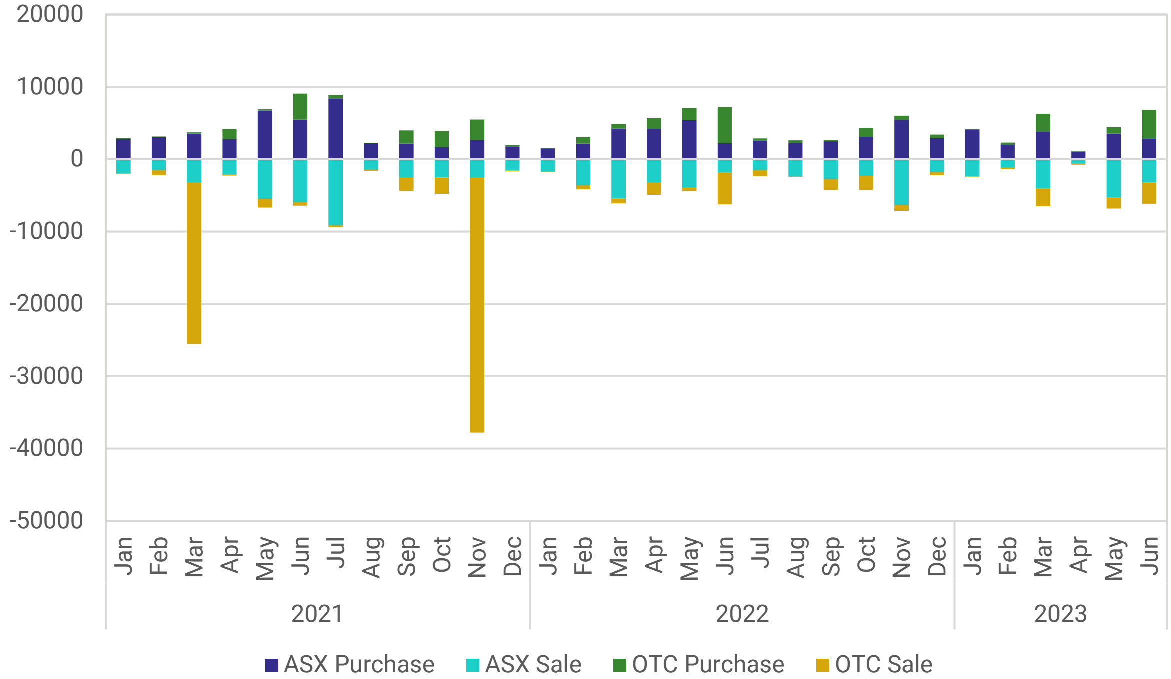
Figure 4.3 Traded volume remains subdued

Total traded volumes (GWh) of ASX and OTC contracts bought and sold, excluding caps, options and weather derivatives, from January 2021 to June 2023, all delivery periods, by region

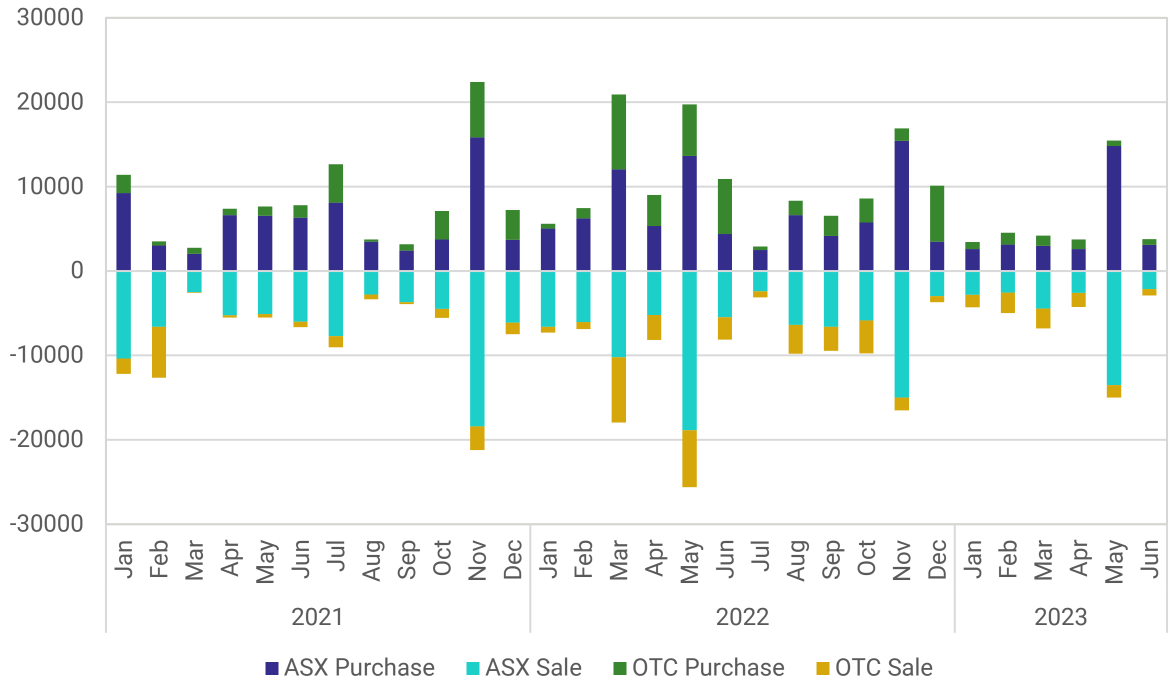
New South Wales



Victoria



Queensland



South Australia

Source: ACCC analysis of hedging contracts data.

Note: In order to avoid the disclosure of confidential data provided by suppliers, the chart for South Australia does not distinguish between ASX and OTC trades.

4.2.3. Most trading activity still occurs on the ASX

Figure 4.3 shows that most contract volume in our data is traded on the ASX rather than other platforms. This is driven by the trading behaviour of large generators and gentailers, who trade more frequently and in larger volumes than small retailers.

Trading on Financial and Energy Exchange (FEX) Global remains extremely low. Only 25% of larger generators and gentailers and no small retailers in our sample trade on the platform.

Of those in our survey who did not use the platform, 58% of larger generators and gentailers reported that they did not use it because their hedging needs were met elsewhere and there was insufficient liquidity on the platform. 67% of small retailers reported that they did not use it because their hedging needs were met elsewhere.

4.3. The types of contracts traded remain largely unchanged

Swap contracts, particularly flat swaps, remain the most common product type traded. There is no indication in our data that their use is reducing relative to other product types. Similarly, trading of non-traditional products, such as weather derivatives, insurance-like products, and products shaped to a particular time of day, has not materially increased. Caps with strike prices above $300/MWh were one type of new product that emerged in 2022, but their use has also not increased in 2023.

The minimal change in the type of hedging instruments traded is despite a general expectation among market participants that the hedging product mix will need to evolve as the energy transition progresses. We discuss this issue in detail in Chapter 5.

4.3.1. Flat swaps remain the most common product type traded

The volume of flat swaps as a proportion of all ASX and OTC contracts traded in our dataset has remained steady in comparable periods between 2021 and 2023, representing approximately 70% of total volume purchased as shown in Table 4.1.[93] In some cases, we have even noted a slight increase in the proportion of flat swaps traded.

A decrease in the supply and demand of traditional contract types is predicted in the future. Our results make clear that this change in supply and demand of flat swaps has not yet emerged in any significant way. A material decrease in their traded volume may not occur until coal power plants retire or a significant number approach retirement. The likely impacts of retiring coal and gas power plants on the contract market is discussed further in Chapter 5.

[93] Options have been excluded from the total volume (MWh) calculations.

Table 4.1 The proportion of flat swap contracts purchased has not materially changed from 2021 to 2023

Percentage of flat swap contracts (of total volume purchased) purchased from 2021 to 2023

Time period	Total volume purchased (MWh)	Total volume of flat swaps purchased (MWh)	Percentage of swaps (%)
2021 calendar year (1 Jan–2021 - 31 Dec 2021)	421,183,723	291,924,248	69.3%
2022 calendar year (1 Jan–2022 - 31 Dec 2022)	361,673,142	261,052,572	72.2%
2021 Up until June (1 Jan–2021 - 30 Jun 2021)	237,938,523	165,670,493	69.6%
2022 Up until June (1 Jan–2022 - 30 Jun 2022)	197,766,802	140,453,237	71.0%
2023 Up until June (1 Jan–2023 - 30 Jun 2023)	160,696,099	107,292,792	66.8%
2022 financial year (1 Jul–2021 - 30 Jun 2022)	381,012,003	266,706,992	70.0%
2023 financial year (1 Jul–2022 - 30 Jun 2023)	324,602,439	227,892,127	70.2%

Source: ACCC analysis of hedging contracts data.

Note: Options are excluded from the total volume purchased, as the volume ultimately exercised is unknown.

4.3.2. Occasional trading of caps with high strike prices has continued since mid-2022

A cap contract places a ceiling on the price a buyer will pay for electricity in the future. This is considered an insurance style product, providing retailers protection against high-priced periods, but allowing them to benefit from low-priced periods. All ASX-listed cap contracts have a strike price of $300/MWh. Participants can currently negotiate caps with other strike prices OTC, but this is very rare.

In our November 2022 report, we observed a reduction in the trading of ASX caps and a rise in the trading of OTC caps. During a period of high prices in late-2022, where the difference between the spot-market price and the ASX cap strike price narrowed, the viability of typical cap contracts with a strike price of $300/MWh was questionable for generators. This resulted in the emergence of cap contracts with strike prices above $300/MWh.[94]

Our analysis of more recent contract data indicates that after the trading of caps with strike prices above $300/MWh emerged in mid-2022, it peaked in September 2022. We observed 54 trades of caps with strike prices above $300/MWh between May and November 2022, compared to 38 such trades between December 2022 and July 2023.[95]

94 ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 51.

95 These figures may include double counting of some trades, where we have collected information from both parties.

The slight decline in trading of these products in early 2023 aligns with the easing of spot prices from their 2022 peak. When the spot price is lower and less volatile, it is more viable for generators to sell caps with a strike price of $300/MWh.

Our data indicates that in the future, caps with high strike prices are likely to be available and sold when spot price and volatility are high, but that demand for them is likely to be low when spot prices and volatility are low. If periods of high price and volatility become increasingly common in the future as a result of the energy transition, we would expect to see high-price caps more commonly traded and become a fixture in the mix of hedging products used by retailers. While the OTC market is the natural place for these products to be traded at the moment, there is likely to be a demand for cap products with strike prices above $300/MWh on financial exchanges in the future.

4.3.3. Non-traditional products continue to be traded but in low volumes

As indicated in our November 2022 report, we expect that demand for new products will grow, and the availability of traditional baseload products will decline as the energy transition progresses.[96] We would expect to see a greater diversity of, and higher uptake of, non-traditional hedging products.

Some newer products used by retailers and generators seen in our data over the past few years include:

- **Weather derivatives**: an insurance-style hedging contract which comes into effect when a pre-specified weather condition occurs (for example rainfall, temperature, or wind).[97]
- **Solar shape**: a fixed volume swap contact covering the hours and variation in power output typical of a solar generation profile. As the power output varies with time of day, these are not flat contracts.[98]
- **Inverse solar shape**: a fixed (but not flat) volume swap contract where the power output profile can combine with a Solar Shape contract to form a flat swap. It allows buyers to access fixed volume and prices in periods generally not covered by solar generation.[99]
- **Super-peak shape**: a swap contract that targets a time of day where prices are expected to be highest and that is more precise than traditional peak contracts (which covered the historical peak period from 7am to 10pm). This 'super-peak' period is increasingly getting shorter and shifted to the evening, due to the increasing contribution of solar power.[100]

From January 2021 to July 2023, there has not been a material increase in the trading of newer products. The volume of non-traditional products continues to be much smaller than traditional hedging contracts. Due to this rarity, it is difficult to establish trends in the trading of these products. However, as more coal and gas generation assets retire, we expect the trading of traditional hedging products such as flat swaps to decrease given thermal generators are the primary providers of those products.

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96 ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 38.

97 Energy One, Reduce your risk of weather events and generator outages, Energy One, 13 October 2022, accessed 22 October 2023.

98 ARENA, Contract Performance Report, November 2020, accessed 22 October 2023, p 24.

99 ARENA, Contract Performance Report, p 24.

100 ARENA, Contract Performance Report, p 16.

It is important to note that all non-traditional products described above must currently be traded OTC. In order to support the energy transition and market competition, it is important that new hedging products are also made available on the ASX and FEX. This issue is explored further in Chapter 5.

4.4. Smaller retailers hedge over shorter time horizons

Trading strategies may vary significantly between retailers, who use diverse combinations of contract types and differ in how far in advance they purchase contracts to manage risk.

In our November 2022 report, we observed that both large and small retailers relied on a variety of contract types. Most tended to trade swap, cap and swaption contracts in varying proportions, although around a third of small retailers almost exclusively traded load-following swaps (see Section 3.2.4 of our November 2022 report).[101]

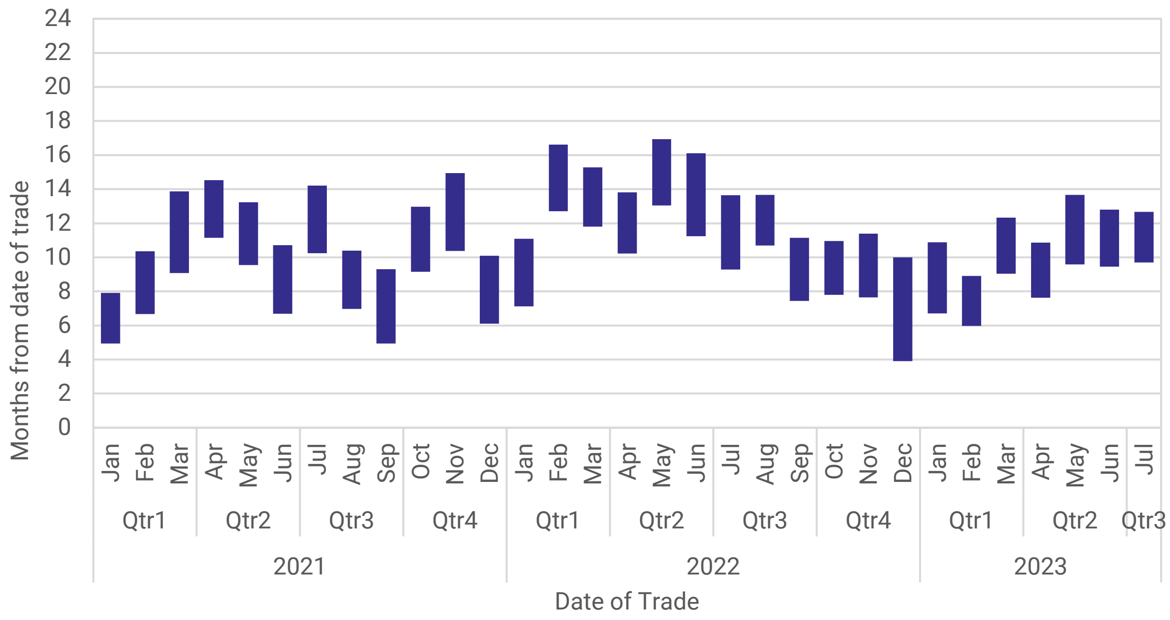
Figure 4.4 shows the average time from the date of trade to the start of the delivery period for all contracts in our dataset, represented by the bottom of each bar. The average time from the date of trade to the end of the delivery period is represented by the top of each bar. We can see that small retailers hedge over shorter and more varied time horizons than large retailers.

101 A swaption contract is an option where the underlying contract is a swap.

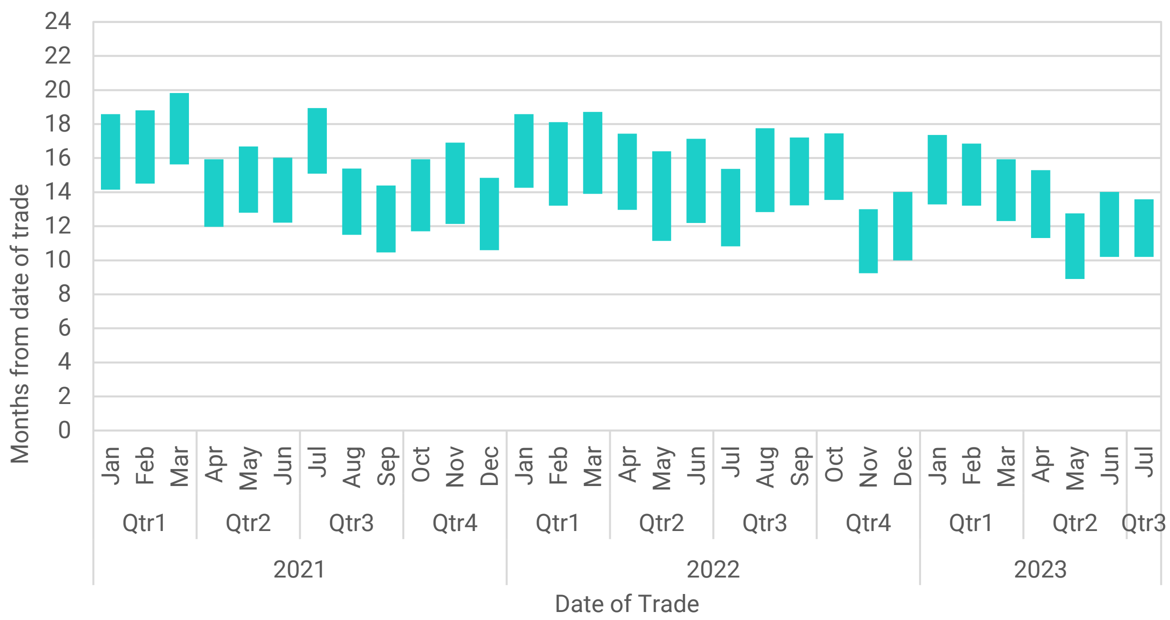
Figure 4.4 Contract time horizons vary between small and large retailers

Average delivery period of purchased contracts from January 2021 to July 2023

Small retailers



Large retailers



Source: ACCC analysis of hedging contracts data.

Over the period from January 2021 through to July 2023, small retailers purchased contracts between 4 and 13 months in advance of their delivery start dates on average, with a typical contract length of 4 months. Large retailers purchased contracts between 9 and 16 months in advance of delivery start dates on average, with a similar typical contract length. Note that these are average values and that real contract lengths are commonly 3 months, 6 months, or 12 months.

Contracting over shorter time horizons makes retailers more exposed to spot market conditions. This may be intentional in some cases, as expectations of reducing spot-market prices may motivate retailers to take on more risk by delaying purchases until closer to delivery, or to choose contracts covering shorter time periods.

For example, shorter time horizons for large retailers in November 2022 could be explained by expectations of government intervention and the likely price implications. On 9 December 2022, the National Cabinet agreed to introduce temporary caps on the price of coal and gas to mitigate the impact of elevated wholesale spot prices, which had peaked in July 2022 due to a combination of high input costs, high demand, and generator unavailability.[102]

These events coincided with marked falls in both wholesale spot and contract prices. Large generators and gentailers purchased contracts only 9.2 months on average ahead of delivery in November 2022, which is 4.3 months earlier than October 2022 and 2.9 months earlier than November in the preceding year.

However, in the case of small retailers, contracting over shorter time horizons could also reflect the financial challenge of managing margin and collateral requirements, as hedging further in advance requires entering into more contracts simultaneously. Information on these financial constraints is provided in section 5.1.5.

4.4.1. Contracting time horizons play a role in standing offer price determinations

The wholesale cost components of standing-offer price caps are intended to reflect the wholesale costs of a typical electricity retailer. In setting these cost components, the Australian Energy Regulator and Essential Services Commission of Victoria make representative calculations for how retailers build a hedge book over time. For example, longer contracting time horizons could be used in cost estimations, on the assumption that retailers seek to smooth short-term price volatility, such that their wholesale costs reflect the long run average.

The 2023–24 Default Market Offer methodology takes all available trades on the ASX from the first date of trade, which approximately equates to a 2 to 3-year time horizon, while the Victorian Default Offer assumes this occurs over a 12-month period (see also section 3.1).[103]

Figure 4.4 demonstrates that the average contract time horizon for large and small retailers is consistently less than 2 years and often less than one year. Large retailers purchase contracts only 12.3 months ahead of delivery on average while small retailers tend to purchase contracts only 9.3 months ahead of delivery on average.

As these values are averages, we would expect that most retailers begin building their hedge books further in advance. However, in periods where contract prices are rapidly increasing, the contracting time horizon assumptions used for calculating the Default Market Offer could underestimate retailer costs if they overestimate the portion of far-in-advance contracting that retailers do.

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[102] ACCC, *Inquiry into the National Electricity Market: November 2022 report*.

[103] AER, *AER – Final determination – Default market offer prices 2023–24*, p 16; ESC, *Victorian Default Offer 2023-24: Final Decision* pp 19–20.

Both the Australian Energy Regulator and Essential Services Commission of Victoria have considered the appropriateness of hedging horizons in their recent Default Market Offer and Victorian Default Offer determinations, and have provided reasoning for maintaining their approaches.[104] Given that the impact of the assumptions depends on the market conditions at the time, and that there is potential for small retailers to be disadvantaged in some situations, it is appropriate for regulators to continue considering this issue.

104 AER, *AER – Final determination – Default market offer prices 2023–24*, p 16; ESC, *Victorian Default Offer 2023-24: Final Decision*, pp 19–20.

5. Financial risk management by small retailers

Key Points

- Most small retailers still do not have access to ASX hedges. Lack of access to the ASX can impact small retailers' ability to compete for customers because it reduces their options for managing spot-market risk.
- Generally, small retailers can meet their minimum risk-management requirements by obtaining the contracts they need over the counter. However, some have reported difficulty in doing so, which may further limit their ability to compete for customers.
- As the energy market transitions to predominantly renewable energy, there is likely to be greater price volatility in the spot market, driven by weather conditions. As the market changes, financial risks faced by generators and retailers will also change, making some current hedging products and practices unsuitable.
- Firm power from renewables may be achieved through the combination of storage and generation assets working together across large geographical areas. In this environment, standalone retailers will need to source a wide variety of contract types from many counterparties, in a way that guarantees them stable wholesale electricity prices. This complexity will have a greater impact on smaller standalone and new-entrant retailers and may become unmanageable if new hedging products and alternative risk-management technologies do not emerge in advance of the changing financial risks.
- Hedging products currently available on the ASX are likely to be poorly suited to managing risk in the future. There is a dilemma, as the ASX may be unable to list new products without sufficient demand, but sufficient demand may not arise if new products are not available on the ASX. There may be a role for government in addressing this issue.
- There is no guarantee that the reduction in the supply of traditional hedging contracts as coal plants exit the market will be replaced by similar volumes or types of contracts from new renewable generators in a timely manner. Government support of renewable assets risks exacerbating this by eliminating the need for generators to sell contracts to retailers to recover their costs of investment. Government measures may be needed to ensure that standalone and new-entrant retailers have access to hedging contracts while the contract market adapts.
- Stakeholders have raised concerns that regulatory interventions aimed at reducing risk to retailers by decreasing spot-price volatility would reduce existing incentives for investment in generation capacity. While retailers' ability to manage risk should be considered in assessing any regulatory interventions in the market, it should not necessarily drive them.
- In response to these concerns, we recommend:
  - Government investigate, in consultation with the ASX and market participants, whether there are ways to support new hedging products being listed on the ASX in a timelier manner.

- Government-funded variable renewable energy and storage projects should contribute to contract market liquidity. This could be achieved by making more contracts available from government-funded assets. Making these contracts available first to qualified standalone and new entrant retailers should also be considered.

As discussed in Chapter 4, we are still observing the effects of the energy market volatility and suspension in 2022 in current prices and trading behaviour in the contract market. Our November 2022 report also identified concerns around how market conditions in 2022 were affecting small retailers' ability to manage their risks, and by extension, their ability to compete and expand.

This chapter examines:

- Small retailers' experiences of market conditions since August 2022, including their ability to manage spot-market risk and compete for customers.
- How the energy transition is expected to affect standalone and new-entrant retailers' ability to hedge in the future.

The ACCC's findings about the current experience of small retailers in the contract market are predominantly based on survey data collected from market participants through our compulsory information gathering powers. The survey questions targeted areas of concern identified in our November 2022 report and through stakeholder engagement. Due to complexity and variation in trading strategies, trading data alone cannot answer fundamental questions like how well retailers are able to manage spot-price risk. Our mandatory survey data therefore provides valuable additional insight into the challenges faced by small retailers in the contract market. The current experience of small retailers also provides an indication of the barriers that new entrants may face, both now and in the future.

To inform our consideration of the long-term evolution of the contract market, the ACCC commissioned an independent expert, Frontier Economics, to prepare a report, '*Future financial risk management in the NEM*' (see Appendix D).

5.1. Many small retailers are experiencing challenges obtaining contracts

As of July 2023, our survey results indicate that most small retailers could still obtain the contracts they required to manage their spot-market risk.

However, our survey data identified several challenges small retailers currently face in obtaining contracts. While most small retailers can adequately meet their minimum risk-management needs, many feel they are unable to follow their preferred hedging strategy. This likely means they are either exposed to more risk or are spending more money to manage their risk than they feel is optimal. Specific challenges encountered by small retailers include being unable to trade on the Australian Securities Exchange (ASX), difficulty accessing some products over-the-counter (OTC), and limited choice among OTC counterparties.

5.1.1. Some small retailers cannot currently execute their preferred hedging strategy

Many small retailers were unable to execute their preferred hedging strategy at some point over the 18 months preceding July 2023. If a retailer is unable to execute their preferred hedging strategy, it may mean they are paying more than necessary to manage their spot-market risk, which can affect their ability to compete and expand in the market. In some cases, it may also mean they are exposed to more risk than is ideal for their business objectives. Box 5.1 provides further information on the role of hedging strategies.

Box 5.1 Hedging strategies

Finding an advantageous hedging strategy is one of the primary ways that retailers can outperform their rivals. Retailers have risk-management policies that provide high-level guidance on how their energy trading staff should approach risk management. The minimum acceptable protection from spot-market risk could be included in these policies. However, a retailer's objective when determining a hedging strategy is not just to fulfill their minimum requirements, but also to reliably procure wholesale electricity at the lowest possible price.[105]

There is a variety of possible strategies that retailers could employ. Each hedging choice they make will influence both the average price at which they purchase wholesale electricity, and the risk they expose themselves to in doing so.

One general rule is that a retailer must make a trade-off between the amount of risk they are exposed to and the amount they pay to protect against that risk. Being more exposed to the spot market can save the retailer money on average but increases the chance of making losses or having to shed customers if a significant period of high spot prices occurs. Conversely, excessively reducing risk wastes money and might prevent the retailer from offering competitive prices to customers. A key strategic decision is therefore how much risk the retailer chooses to accept, and this may change depending on market conditions.

Regardless of how much risk the retailer accepts, some strategies are objectively better than others. For example, 2 retailers could employ different strategies that ultimately offer the same protection from high-spot-price risk. Despite offering the same protection, the strategies could vary in the types and volumes of hedging contracts that were purchased, and the time at which they were purchased. In this scenario it is highly likely that one strategy would cost more than the other to employ, giving that retailer a competitive advantage over the other.

One strategic decision a retailer can make is the extent to which they trade on the ASX compared with OTC. Trading OTC provides retailers with the flexibility to negotiate bespoke contract terms with counterparties, which may allow them to tailor aspects of their strategy more precisely to their circumstances and objectives. However, there is a significant transaction cost when trading OTC, as staff must invest time into finding and negotiating with suitable counterparties.

Conversely, ASX-trading offers much less flexibility, but is much more suitable for high-frequency and high-volume trading. For example, if a company wishes to purchase contracts whenever they drop below a certain price threshold, this would be better

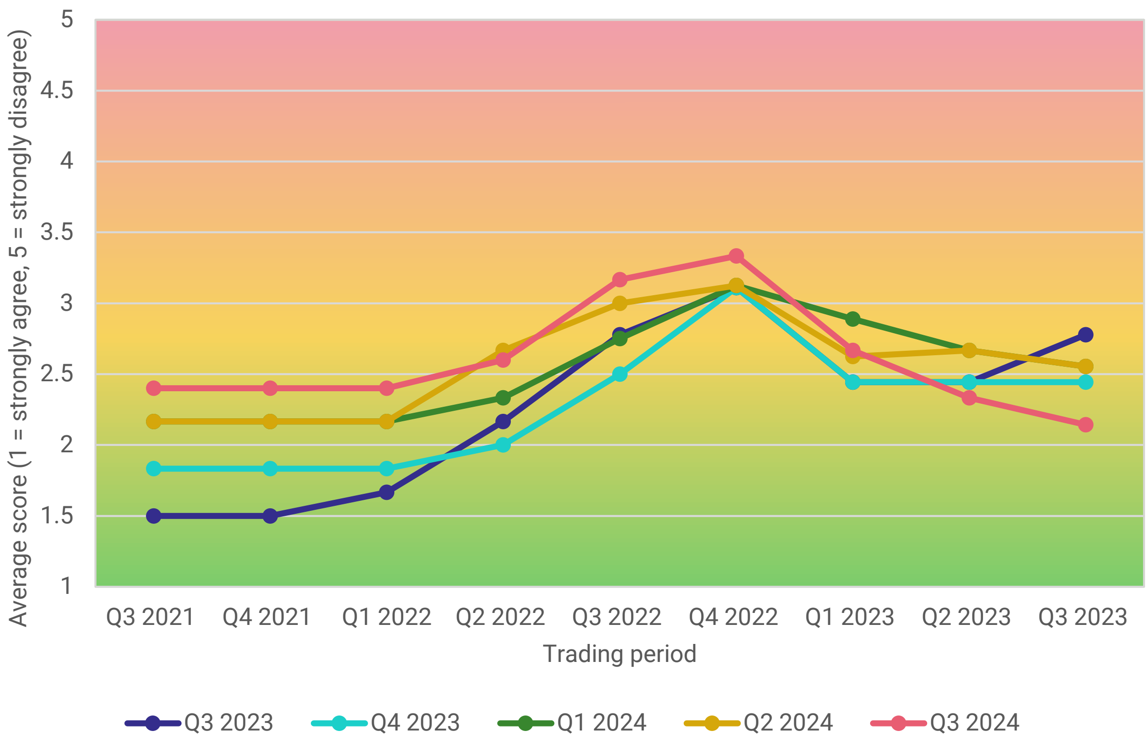
105 There are exceptions to this, such as pool-price pass-through strategies, where a retailer might accept high wholesale prices or the risk of high prices because they can pass them on to their customers.

achieved on the ASX where the company can buy or sell as frequently as they like (ignoring financial constraints) with minimal labour cost.

Our qualitative survey asked small retailers to indicate how well they were able to follow their preferred hedging strategies, over a variety of trading dates and delivery periods. For each date of trade and delivery period, retailers were asked to indicate their level of agreement with the statement, 'market conditions were such that the Company was able to execute its target hedging strategy in that quarter with respect to this delivery period'. The average of responses for each date of trade and delivery period is shown in Figure 5.1.

Figure 5.1 Many small retailers have been unable to execute their target hedging strategies at some point over the 18 months preceding July 2023

Average of retailers' level of agreement that the Company was able to execute its target hedging strategy in that trading quarter (from quarter 3 2021 to July 2023) with respect to each delivery period (quarter 3 2023 to quarter 3 2024)



Source: ACCC analysis of electricity retailer survey data.

Note: Retailers survey responses were collected in July 2023. Meaning that responses for Q3 2023 trading period may not be representative of the entire quarter.

Prior to 2022, small retailers were generally able to follow their preferred hedging strategies. However, many became unable to follow their preferred hedging strategy in the second half of 2022. This corresponds with the period of extreme spot prices and volatility in the NEM, following the market suspension. Conditions have improved for small retailers since then, but average retailer responses to our survey are still neutral as of quarter 3 2023.[106] This indicates that a significant portion of retailers are continuing to face challenges executing their target hedging strategy.

106 Due to the dates that we issued our section 95ZK notices, the data in quarter 3 2023 only includes data up until 19 July 2023.

Our survey results provide some insight into the nature of these challenges faced by small retailers. We asked survey recipients whether they were able to adequately comply with their risk-management policies between August 2022 and July 2023. All small retailers surveyed indicated that they were able to comply with their policies. This indicates that they can meet their basic risk-management needs. However, some reported that they had needed to change the composition of their hedge book, change the counterparties they traded with, and/or change day-to-day trading strategies in order to comply with their risk policies.

The results shown in Figure 5.1 suggest that small retailers are finding the current market conditions more challenging than conditions prior to 2022.

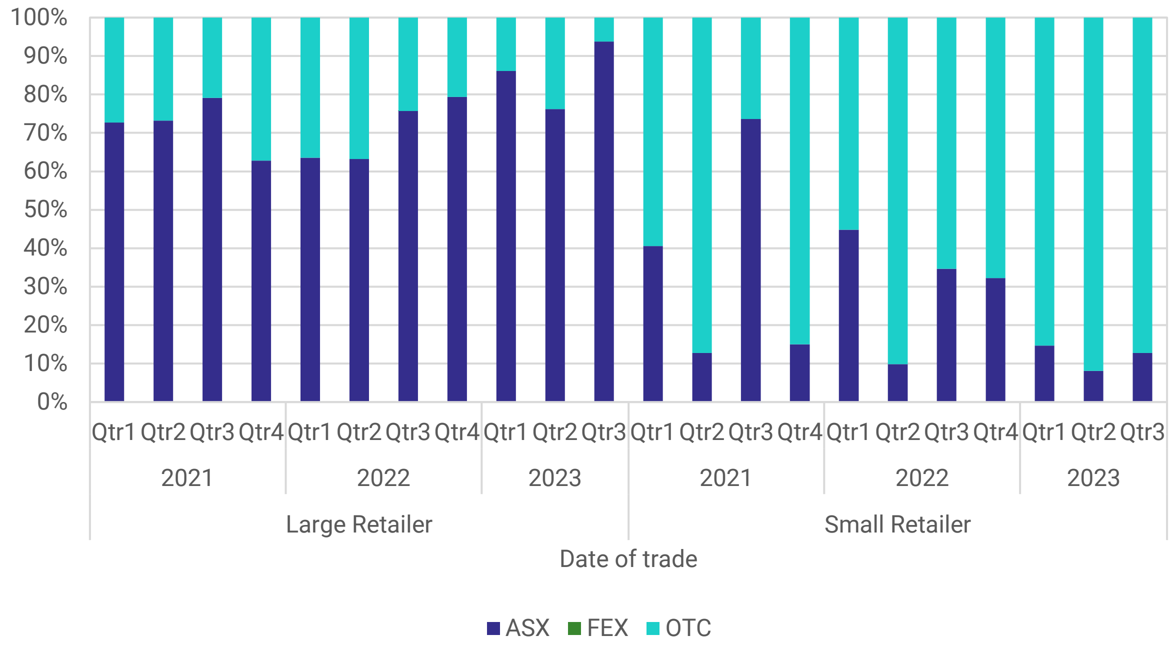
5.1.2. Many small retailers still cannot trade on the ASX

Around 90% of small retailers in our survey cannot access hedging contracts on the ASX. It means those small retailers only have one major source of hedging contracts: the OTC market. In contrast, all larger generators and gentailers that we surveyed have access to the ASX. The primary reason that most small retailers are unable to trade on the ASX is that they cannot find a clearing participant that is prepared to work with them. In some cases, this could be because the clearing participants perceive small retailers to be riskier clients than larger participants.

We observed that access to the ASX was a problem in our November 2022 report, meaning that many small retailers have been unable to purchase ASX contracts for more than 12 months. This is also reflected in our trading data. Figure 5.2 shows that ASX trades now account for less than 15% of small-retailer-traded volume.

Figure 5.2 Small retailers have high dependence on OTC trading

Proportion of total volume of contracts traded by large and small retailers OTC, on the ASX and on FEX, Q1 2021 to Q3 2023



Source: ACCC analysis of hedging contracts data.

Note: Figure excludes power purchase agreements, and load following and generation following shaped contracts.

Approximately 80% of hedging contracts in our data are traded on the ASX.[107] Lack of ASX access therefore limits participants to a small portion of the market, which could potentially be a competitive disadvantage. The majority of small retailers indicated that ASX hedges feature in their preferred risk-management strategy.

Generators and gentailers are dependent on ASX hedges for managing risk. When asked about their level of agreement with the statement, 'the company could manage spot-market risk effectively without using ASX hedges', 33% strongly disagreed and a further 33% disagreed. Extensive trading of ASX hedges by larger participants compared to small retailers is expected, given their need to trade in higher volumes to manage their risk. In the case of gentailers, they both buy and sell contracts in high volumes. This means they have twice as many variables to consider when managing their net hedge position, increasing their need to trade in response to changes in forecast supply and demand of electricity. Therefore, access to a financial exchange is likely necessary for efficiently making high numbers of trades with a wide range of counterparties.

Lack of ASX access significantly reduces options for managing spot-market risk for some small retailers; they can only find the hedging contracts they need in the OTC market. In responding to our survey, 67% of small retailers indicated that they cannot, or could not, compete effectively in the retail electricity market without using ASX hedges as part of their risk management.

In addition to the immediate challenge of staying competitive, there is the potential for small retailers to be forced out of business if they cannot manage their spot-market risk. 44% of small retailers surveyed stated that that they cannot, or could not, effectively manage spot-market risk without the use of ASX hedges. While this implies that the majority of small retailers can currently adequately manage spot-market risk without ASX hedges, our results make clear that lack of ASX access does impact on their ability to effectively compete.

The most common reason cited by small retailers for not being able to trade on the ASX is that they could not find a clearing participant (or broker) that was willing to work with them. The role of clearing participants and brokers in the market is described in Box 5.2. Our survey responses indicate that in some cases, small retailers had reached credit or risk limits with clearing participants. In other cases, they had been unable to engage with clearing participants at all.

Small retailers may sometimes be less financially secure than larger market participants. This can mean they pose a greater risk to clearing participants, who are the parties responsible for ensuring the retailers' contractual obligations are met. This risk intensifies in volatile market conditions, where there is greater uncertainty as to how much money a retailer will owe when a contract is settled.

As of 20 October 2023, the ASX listed 6 Australian electricity brokers on its website, and 5 ASX 24 clearing participants supporting Australian electricity derivatives trading.[108] The ASX also recently authorised a new clearing participant that is now clearing electricity derivative products.

We noted in our November 2022 report that in practice, almost all trading was concentrated to just a small number of brokers and clearing participants.[109] Having almost all energy futures trading cleared by a very small number of participants is a concern, because those participants bear a majority of the market risk. Those participants are then vulnerable to the

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107 Percentage is based on number of contracts rather than volume.

108 ASX Energy, ASX Commodities Clearer Contacts, ASX Energy website, March 2023, accessed 20 October 2023.

109 ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 47.

risks of the market, which in turn makes the entire market vulnerable. The clearing participants are aware of this, which is why some opted to stop taking on customers amid the market volatility in 2022, as we have previously reported.[110]

As we have seen, we would expect small retailers to be the first impacted when clearing participants restrict their business, because they are comparatively small clients that clearing participants may perceive as riskier in some cases. As stated, the ASX has recently authorised a new clearing participant. This is encouraging; however, it remains to be seen whether clearing participants will be willing to work with small retailers in volatile market conditions.

5.1.3. Small retailers often experience difficulties obtaining the contracts they require over the counter

Smaller retailers in our survey faced challenges in the OTC market, with some reporting difficulty engaging OTC counterparties and accessing certain types of hedging products. Other challenges reported by small retailers include having to change the counterparties they traded with and having to change their trading strategies. This is concerning given the majority of small retailers purchase all their contracts in the OTC market.

67% of small retailers reported that they can obtain all the contracts they require in the OTC market. However, some retailers cannot, and most contract types were reported as being difficult to obtain by at least some retailers. There are also some less-frequently-traded products that some retailers were completely unable to obtain, such as shaped products targeting a particular time of day and Asian options.[111]

Challenges reported by small retailers in the OTC market include difficulty engaging in discussions with suitable counterparties, contracts being offered on what they consider to be unreasonable terms, and potential counterparties not offering contracts at all. As discussed in section 5.1.2, a possible reason for this is that small retailers may pose a greater financial risk to counterparties than larger participants. While most small retailers reported they had some choice between suppliers of OTC contracts, a small portion indicated they had no choice. No retailers indicated that they had a lot of choice between suppliers of OTC contracts.

Despite these challenges in obtaining OTC contracts, no retailers reported that they were unable to obtain swaps, caps, or load-following swaps, which are the products predominantly currently used.

5.1.4. Contract market conditions affect retail competition

New entrant retailers that are not vertically integrated or rely exclusively on other alternative risk management strategies (see sections 4.1.3 and 5.2.4), require access to hedging contracts to manage their spot-market exposure. Expansion through the acquisition of customers also generally requires a retailer to obtain a greater volume of hedge cover, as the additional customer load increases their spot-market exposure. Difficulties accessing hedging contracts could therefore have a direct impact on retail competition.

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110 ACCC, *Inquiry into the National Electricity Market: November 2022 report*, p 47.

111 An Asian option is an option where the underlying product price is determined by the average price of that product over some pre-set period.

In response to our survey, 67% of small retailers reported that obtaining hedges is not currently the most significant barrier to increasing their customer base, while 33% reported that it is. Most small retailers can currently acquire the contracts they need to manage their risk and compete for customers. However, the results do suggest that recent contract market conditions could be having an impact on retail competition and be a barrier (just not the most significant barrier in some cases) to acquiring more customers. The impact on competition could be much greater if market conditions worsen.

Lack of ASX access is an ongoing concern and could further impact small and new-entrant retailers' ability to effectively compete if it persists. Small retailers could be disadvantaged if market conditions allowed OTC prices to exceed equivalent prices on the ASX. Dependence on the OTC market likely places practical limits on when and how much a retailer trades, creating a barrier to retailers growing beyond a certain size.

5.1.5. Margin, credit-support and prudential requirements can be further barriers to effectively managing risk

In our November 2022 report, we discussed how increasing price volatility had resulted in higher margin and collateral requirements being imposed on retailers. We also noted that the Australian Energy Market Operator (AEMO) prudential requirements added an additional financial pressure at a time when smaller retailers were facing a challenging landscape of high spot-market prices. Further information on clearing participants, margin and prudential requirements are provided at Box 5.2.

Box 5.2 Clearing participants, margin and prudential requirements

Hedging contracts are settled by one party compensating the other for the difference between the wholesale spot price and the price that was agreed in the contract. Due to uncertainty in wholesale spot prices (see section 5.2.1), the amount of money that a retailer needs to pay when a contract is settled is hard to predict. This creates a risk that a party might not be paid what they are owed, which can in turn make it difficult for them to pay what they owe to others. This type of financial event can cause a chain reaction placing all market participants at risk.

To protect against this risk, financial exchanges require companies to purchase and sell contracts through an authorised clearing participant that acts on their behalf. The clearing participant posts margin to the exchange that is sufficient to cover all plausible contract settlement outcomes. Clearing participants then collect that margin from their clients to protect their own financial interests.

Retailers and generators may also seek to manage the risk of counterparties being unable to pay when entering OTC contracts. This involves asking for money or credit support upfront.

The risk of a financial event having widespread effects on all market participants also exists in the wholesale spot market. If retailers cannot pay for the electricity their customers use, then generators may not receive the money they need to operate. This could put the entire power system at risk in extreme scenarios. To mitigate this risk, retailers must meet 'prudential requirements', where they keep a certain balance of money with AEMO so that AEMO can guarantee paying generators when they are dispatched. AEMO prudential requirements do not directly relate to margin requirements, but both tend to be higher in volatile market conditions.

Therefore, the amount of money that retailers must have available to meet margin and prudential requirements can increase significantly with increased market volatility. While margin and prudential requirements are somewhat independent of contract prices, under certain market conditions, retailers can simultaneously face extremely high contract prices and increased margin and prudential requirements.

In responding to our recent survey, 22% of small retailers agreed that meeting margin and credit-support requirements was a significant financial challenge for the company as of July 2023, while 44% disagreed. Opinions varied on whether meeting margin and credit-support requirements was more of a challenge since August 2022 (when we last collected data), but most retailers indicated that there was no significant change.

Opinions were similarly divided on AEMO prudential requirements, with 33% of small retailers indicating that they were a significant financial burden and 33% indicating that they were not. However, 56% of small retailers agreed that it became more difficult to meet AEMO prudential requirements during the energy events of 2022 than in prior periods.

These results suggest that margin, credit-support and prudential requirements are currently manageable for retailers in general. However, these requirements can add to the other challenges of managing risk in volatile market conditions.

5.2. The energy transition will transform the contract market

This section discusses the challenges market participants are likely to encounter in managing their financial risks in the future as the National Electricity Market (NEM) transitions away from thermal generation to variable renewable generation and storage.

Any future-focused discussion about the evolution of the contract market and its implications for market participants will be speculative in nature. It also requires understanding the historical market conditions since the commencement of the NEM in 1998 and how those conditions have changed.

As noted above, to inform our consideration of the long-term evolution of the contract market, the ACCC commissioned an independent expert, Frontier Economics, to prepare a research report, '*Future financial risk management in the NEM*' (see Appendix D). The ACCC requested that Frontier Economics' report explore:

- the long-term evolution of the contract market in the context of changes in the generation mix, wholesale market, government policy and broader market developments
- whether changes in the contract market are likely to affect retailers' ability to manage wholesale spot-price risk in the future
- how contract markets can continue to appropriately support retailers' ability to manage risk in the future.

As an input to their report, Frontier Economics, together with representatives from the ACCC, led meetings with industry stakeholders. To supplement stakeholder feedback, Frontier Economics also reviewed academic literature, policy documents, rule change proposals and other publications discussing the prospective state of the contract market.

The ACCC expects there to be greater price volatility in the spot market, driven by weather conditions, as the energy market transitions. As coal power plants retire, there will likely be a reduction in the number of generators that can offer flat swaps. Retailers' need for products that guarantee prices at all times of day is also likely to reduce, as typical spot prices during the middle of the day continue to drop with increased solar penetration. It is therefore likely that there will be a change to both the demand and supply of traditional hedging products.

As noted in section 5.1, small retailers are already encountering a range of challenges in obtaining the contracts they require to effectively manage spot-market risk. As the energy market transitions, standalone and new-entrant retailers may find financial risk management increasingly challenging.

5.2.1. Spot price volatility will increase, impacting standalone retailers

One major finding by Fronter Economics was the anticipation of greater volatility between off-peak and peak prices in the spot market as the NEM progresses with the transition. This will make it harder for market participants to predict when high prices will occur, and this uncertainty will translate to risk management being more difficult, particularly for standalone retailers. Additionally, the financial pressure of meeting margin and prudential requirements is greater in volatile environments.

The predictability of generation output will change as the NEM continues transitioning to renewables. The growing proportion of grid and rooftop solar will alter when peak and off-peak prices in the spot market occur. Peak prices will more frequently be driven by the output of generation rather than the occurrence of daily peak demand periods. The nature of the risk that retailers need to manage will therefore change.

Currently, the generation capacity made available by baseload thermal generation in the market is relatively predictable throughout the day. Accordingly, daily peak demand (when electricity usage is at its highest) is a primary driver of peak prices on the spot market. Daily peak demand is usually around 4pm to 9pm.

The rapid influx of grid and rooftop solar over the past 3 years has changed the shape of wholesale electricity prices, daily spot prices, demand curves and demand for baseload (coal) generation during the day.[112] Frontier Economics explains in their report that as the NEM continues through the transition, output from rooftop solar and wind will increasingly be the primary driver of peak prices. That is, peak prices will more frequently be driven by the *output of generation* rather than the *occurrence of peak demand* periods. Solar and wind generation is largely determined by the weather, so weather will have a strong influence on peak prices.[113]

As noted by Frontier Economics, the spot market is already witnessing low off-peak prices from the penetration of renewable generation, particularly due to rooftop solar reducing demand during the day. Peak prices, however, are expected to increasingly be set by high-cost peaking plants in the absence of baseload generators. This is likely to be the case until battery technology can produce sufficient output to cover peak periods over multiple days in a row.[114]

A key theme from our stakeholder meetings was that should very high penetration of intermittent generation in the market eventuate as expected, this would drive increased spot-price volatility and potentially also higher peak prices than we see today. Several

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112 AER, *State of the Energy Market 2023*, p 57.

113 Frontier Economics, *Future Financial Risk-Management in the NEM*, p 20. See Attachment D.

114 Frontier Economics, *Future Financial Risk-Management in the NEM*, p 21. See Attachment D.

stakeholders expressed concern for the ability of independent retailers to manage financial risk in this environment.[115] This is further supported by our survey data, with approximately 90% of the small retailers surveyed agreeing or strongly agreeing that changes to the generation mix in the NEM over the next 10 years will likely make it more difficult for them to hedge their retail customer load.

We share this concern that small and new-entrant retailers could find it difficult to compete when faced with increased spot-market volatility resulting from the changing generation mix through the transition. One reason for this is that managing risk in this environment will be very complex. This will be easier for larger companies with sophisticated trading teams to manage. Vertical integration and other non-financial risk-management options will increasingly become appealing ways to reduce dependence on hedging contracts, but these also favours larger participants. As explained in section 5.1.5, margin and prudential requirements add additional pressure in volatile markets, and this too is more challenging for smaller companies. We discuss the issues of increasing complexity of using hedging contracts and vertical integration in the following sections.

5.2.2. Managing risk will become more complex for retailers

Managing risk will become increasingly complex for retailers as the supply of financially firm contracts declines, the types of contracts available change, and retailers are required to trade with a wider variety of counterparties.

Financially firm contracts provide financial protection at times where intermittent generators are not supplying electricity and prices are high. Currently these contracts are provided by baseload coal fired generators or gas fired peaking generators. As discussed in Frontier Economics' report, it is likely that supply and demand of flat swaps will reduce as coal plants retire, and there is uncertainty around whether contracts from renewables and storage will replace them.

There is therefore a reasonable prospect that retailers will find it materially harder to source affordable, financially-firm contracts. If retailers are unable to easily source these financially firm contracts, they will be exposed to material financial risk, especially if they are not vertically integrated.

Frontier Economics notes the following reasons for this in their report:

> The availability of financially-firm contracts is expected to reduce. This will make it harder for retailers that rely on contracting to source efficiently-priced, financially-firm contracts. Drivers for reduced availability of firm contracts include:
>
> - The retirement of dispatchable generation sources. With a realistic prospect that every region in the NEM is just one coal-fired generation retirement away from there being a material shortage of firm contracts in the region.
> - Decreasing reliability of remaining baseload generators exposes them to an increased risk of unfunded difference payments if capacity is contracted.
> - Vertically integrated operators may prefer to withhold capacity from contract markets to better manage the uncertain weather-driven shape risk associated with their own load.
> - Government-supported generation investments may have a reduced incentive to make contracts available to the market. A key motivation for a generator to

[115] Frontier Economics, *Future Financial Risk-Management in the NEM*, p 20. See Attachment D.

> contract is to provide a reasonable assurance of a stable return. If the method of government support provides a reasonable assurance of stable returns, the incentive to contract will be reduced.[116]

Financially-firm contracts will not disappear entirely while thermal generators remain in the NEM, which is expected to be the case for some time. However, as coal plant retirements progress, the reduced supply of firm physical capacity in the market may result in the remaining thermal generators charging a high premium for these contracts.

Frontier Economics' report raises questions around how the future generation fleet, comprised predominantly of renewables, will provide contracts that retailers can use in place of the flat swaps from thermal generators that they currently most depend on. Frontier Economics indicates that power purchase agreements offered by renewable generators are not financially firm because those generators cannot reliably predict how much power they will produce at specific points in the future.[117] They also note that other renewable generation and storage technologies may not be able to offer sufficient financially-firm contracts.[118]

If batteries and other storage assets can provide financially-firm contracts, another key consideration is that where firm power is currently provided by a small number of large coal plants, reliable power supply will instead be achieved by many different types of renewable and storage assets working in harmony, spread over a large geographical area.

In our view, it is likely that where a retailer can currently purchase flat swap contracts from a small number of counterparties, they will instead need to source a wide variety of (non-financially-firm) contract types from many counterparties, in a way that guarantees them stable wholesale electricity prices. This will likely be very complex, especially if some of those contract types are in short supply. This complexity will likely have a greater impact on smaller retailers, as they are less likely to have access to the resources needed for such sophisticated risk management. While AEMO will ensure that physical supply meets demand, retailers' financial risk management could become unmanageably complex, especially in situations where physical supply barely meets demand.

The only likely scenario where the complexity associated with hedging would not increase for a retailer is if generators or risk-management intermediaries are able, and willing, to package the combination of renewables, storage and geographic spread into firm contracts on the retailer's behalf. That is, another party would take on the additional complexity and risk, passing the cost onto the retailer. While this is possible in theory, the ACCC considers there is no guarantee that it will occur prior to small retailers facing unmanageable risks.

Frontier Economics notes in their report that government-supported renewable investments can have reduced incentives for making contracts available to market. This can arise where government guarantees stable income for the generator. As discussed in section 4.1.1, generators are motivated to enter into contracts because the volatile spot market does not provide them with the revenue certainty they need to ensure they cover their operational, fuel and maintenance costs, and achieve a return on investment. If revenue to achieve this is guaranteed by government, the generator has little incentive to sell contracts to retailers, noting that on average, the spot market will provide better returns.

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[116] Frontier Economics, *Future Financial Risk-Management in the NEM,* p 5. See Attachment D.

[117] Frontier Economics, *Future Financial Risk-Management in the NEM,* p 24. See Attachment D.

[118] Frontier Economics, *Future Financial Risk-Management in the NEM,* p 18. See Attachment D.

5.2.3. The types of contracts and products traded are expected to change

As the transition changes the dynamics and operation of the NEM, it will also change the risk profiles of retailers, and subsequently the types of hedging contracts supplied by generators.

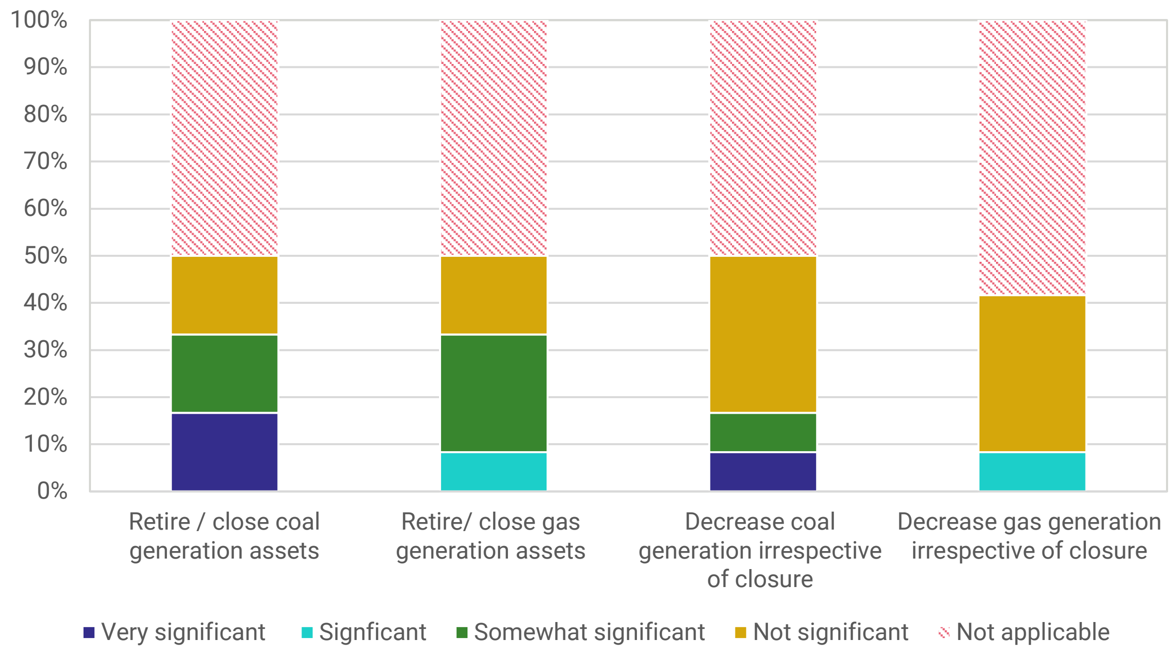
Flat swaps are expected to decline

Stakeholders expect that the types of contracts traded will change over the next 10 years. This is supported by our survey data together with feedback received during stakeholder meetings. Generators and gentailers indicated in their survey responses that they expect the types and volume of contracts they offer will change over the next 10 years. Unsurprisingly, decreasing output from coal and gas generation assets and retiring those assets were cited as significant factors affecting the types of hedges sold over the next 10 years (Figure 5.3).

Flat swaps are traditionally the most traded hedging products because they are well suited to the risk profiles of coal power plants that seek to secure stable revenue to cover their fuel, operation and maintenance costs. As discussed in section 4.3.1, flat swaps remain the most traded hedging products in the market. However, as the output from coal generators reduce, the availability of these traditional hedging products is also expected to reduce.

Figure 5.3 Reduced coal and gas generation will affect the types of hedging contracts available

The significance of different factors, relating to reduced coal and gas generation, affecting the types of contracts sold by large generators and gentailers over the next 10 years

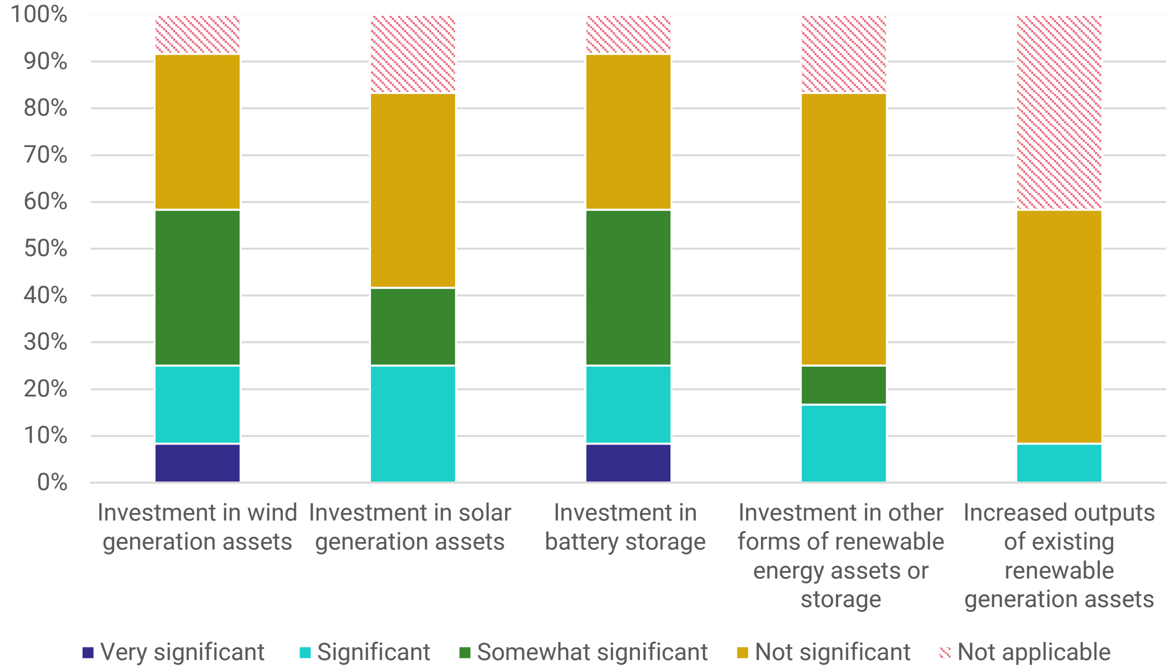


Source: ACCC analysis of electricity retailer survey data.

Investment in a range of renewable assets, such as wind and solar generation and battery storage, were cited as being even more significant as factors that will impact the types of contracts offered (Figure 5.4). Unlike coal and gas, these types of assets are not well suited to offering flat swaps, because they have inconsistent power output.[119] The future generation fleet will likely need to offer different types and volumes of contracts to what we currently see.

Figure 5.4 Increased renewable generation will significantly impact the types of hedging contracts available

The significance of different factors relating to investment in renewables affecting the types of contracts sold by large generators and gentailers over the next 10 years



Source: ACCC analysis of electricity retailer survey data.

New peak and other shaped products are likely to be needed

As outlined in section 5.2.1, weather is expected to drive peak prices in the future, due to its influence on renewable generation. In contrast, peak prices have historically been driven by peak demand. As noted by Frontier Economics in its report, the influence of the weather 'is expected to drive more segmentation of contracting periods through the day rather than the current binary of 'off-peak' and 'peak''.[120]

Frontier Economics also notes:

- For 'off-peak' products, the issue is that spot prices are expected to be very low during these times such that contracting may be of limited value for retailers outside of whatever power purchase agreement arrangements that they might be able to arrange.
- For 'peak' products, the issue is that the current peak products, such as those sold by the ASX, are for a duration that will be too long given the expectation of a shorter peak period. Further, cap contracts are unlikely to be priced high enough for future requirements.

[119] Renewables and batteries are generally not well suited to offering flat swaps independently, but there is the potential for them to combine to offer 'firm' generation that could offer such products.

[120] Frontier Economics, *Future Financial Risk-Management in the NEM,* p 21. See Attachment D.

> In the future retailers may also prefer to rely more on 'insurance' type products, such as weather derivatives. However, these are currently not well traded in Australia and require a sophisticated trading team to arrange'.[121]

Generator and gentailer views were varied on the suitability of hedging contracts currently available for their long-term needs. Approximately 40% agreed that the contract types currently available will be suitable for their company's hedging needs over the next 10 years, while approximately 30% disagreed. These varied results could be explained by different business models of the generators and gentailers in our sample. For example, vertically integrated companies will likely strive to optimise their risk management by balancing their generation and storage capacity with their retail load in each region as the transition progresses. As noted in section 4.1.3, this natural hedge reduces their dependence on the contract market.

In the future, retailers will demand new types of hedging contracts that are quite different to the products currently available. They will seek products that are tailored to the higher levels of intra- and inter-day price variation expected during the energy transition. This is supported by our survey data, where 67% of the small retailers surveyed indicated that the contract types currently available on ASX, FEX or OTC will not be suitable for their hedging needs over the next 10 years. This further emphasises the need for the supply of new hedging products, in line with changes in generation and load profiles that are expected to occur through the energy transition.

Frontier Economics' report suggests a few hedging contract products which may be useful in this context, including:

- super-peak products
- solar-shape swaps
- inverse-solar-shape swaps.

Further information on these products is provided in section 4.3.3.

In the long term, it may be that the low operating costs of renewables mean that spot-market prices are generally so low that retailers are happy to operate without hedge cover much of the time. However, as stated in section 5.2.1. and noted in Fronter Economics' report, there will be occasional extreme high-price events, driven predominantly by weather or unexpected events such as plant outages.

In this environment, retailers will need to manage the risk of those extreme events. This could be achieved through weather derivatives or other insurance-like products. However, as discussed in Chapter 4 and Frontier Economics' report, these products are currently infrequently traded and require a sophisticated trading team to arrange.

New exchange-traded products may be needed prior to liquidity emerging

During the transition, a liquid contract market that is facilitated by exchange-traded products that are fit for purpose, is important for maintaining retail competition.

The Australian electricity hedging contract market is a relatively small financial market by global standards, so there is no guarantee that local demand will be sufficient to attract sophisticated financial organisations to offer the new products and services described

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121 Frontier Economics, *Future Financial Risk-Management in the NEM,* p 23. See Attachment D.

above. It is therefore unclear whether new fit-for-purpose hedging products will be widely available by the time that retailers will need to rely on them.

Stakeholders indicated in our meetings that new products are highly likely to be developed and sold in the OTC market, rather than through the exchanges such as ASX or FEX. Retailers will likely shift towards more bespoke contracting arrangements that more closely reflect the shape risk that they are exposed to in the transitioning market.[122]

If this shift to more bespoke contracts accelerates over the long term, it raises questions about the ability of exchanges, such as the ASX, to create products with high liquidity suitable for exchange trading. This is because trading exchanges may be reluctant to list new products for trading on their platform without sufficient evidence of liquidity or demand from market participants.

Frontier Economics notes in its report that such liquidity is unlikely to emerge, if at all, until baseload generation exits the market. In the absence of these new hedging products, retailers will likely rely heavily on OTC contracts or potentially vertical integration to manage risk. As outlined in section 5.2.1. and discussed extensively in Frontier Economics' report, these market conditions would heavily favour larger incumbents, especially if they occur before small-scale generation and storage assets are a viable option for small or new-entrant retailers.

It is not clear, based on our stakeholder discussions, that new hedging products suited to the future needs of retailers and generators will emerge on the exchanges by the time they are required. Accordingly, the ACCC is of the view that the Government should investigate whether there are ways to support new products being listed on the ASX.

Recommendation 3

Incentives to facilitate the development of new hedging contract products should be investigated

The Government should investigate, in consultation with the ASX and market participants, whether there are ways to support new hedging products being listed on the ASX in a timelier manner.

This could involve coordinating collaboration between the ASX and market participants to identify, design and list suitable products. Other examples could include funding market making incentives within the exchange, or underwriting the risk of new hedging products to reduce margin obligations for retailers until the product becomes more liquid. Some of the types of products that may be needed on the exchange include super-peak products, inverse-solar products, or products that hedge the spread for storage charging and discharging.

5.2.4. Alternative forms of risk management are likely to be increasingly used

Given spot prices are forecast to become more volatile and less predictable in the long term, hedging is expected to become more difficult in the future. As outlined at section 4.1.3, retailers and generators can use alternative risk-management strategies to complement or replace their use of hedging contracts, and we expect that these will become more commonly used.

122 Frontier Economics, *Future Financial Risk-Management in the NEM,* p 24. See Attachment D.

Vertical integration could be increasingly used by retailers to compete

There was a general consensus from our stakeholder meetings that vertical integration would likely be an effective strategy for retailers to manage more volatile spot prices, as outlined in Frontier Economics' report. Further information on vertical integration in the NEM is provided at section 4.1.3.

Small standalone and new-entrant retailers with a defined customer base (in terms of type and geographic location) are typically the most exposed to volatile spot prices. These retailers have fewer options for hedging their risk compared to established gentailers and are more likely to be adversely affected by changing market conditions.

Frontier Economics notes in its report that in the absence of vertical integration, highly sophisticated hedging skills will likely be needed to manage financial risk. Some stakeholders indicated in our meetings that 'the level of sophistication needed was likely to be beyond that available to small retailers'.[123] This is because these retailers are more reliant on the contract market to manage their risk and the types of products upon which they depend will change, becoming increasingly complex. The transaction costs associated with negotiating complex bespoke contracts are also likely to be significant.

In the event retailers increasingly rely on vertical integration to manage spot-price risk, this would impact retail competition by increasing barriers to entry. Frontier Economics has highlighted in its report that if vertical integration becomes necessary to effectively manage risk, this may make it difficult for new retailers to enter the market, as they are typically unlikely to possess the investment grade credit rating required to finance large capital assets.

Barriers to vertical integration may reduce to some extent in the future, as minimum investment to procure renewable and storage assets will likely reduce as technology develops further. Some smaller retailers may therefore be able to source cost-effective generation and storage solutions that match their load profile and risk exposure.[124] However, if this does occur, it will take some time. It is therefore important that retailers can access hedging contracts throughout the energy transition.

New types of hedging contracts, suited to renewables and storage, may not become widely available until a large number of coal plants retire. With each closure, the risk profile of the spot market will likely change in advance of the contract market adapting. There is no guarantee that the market will deliver replacement hedging products by the time that standalone retailers need them.

This problem could be compounded, if larger retailers are increasingly motivated to use vertical integration to manage risk, making them less dependent on the contract market keeping pace with the transition. As discussed by Frontier Economics in its report, these companies may opt to reserve their generation assets to meet their own risk-management needs and reduce their trading activity. This would accelerate the reduction in contracts available to small and new-entrant retailers.

Government measures may be needed to ensure that small and new-entrant retailers have access to hedging contracts while the market adapts. As noted by Frontier Economics' report, federal, state and territory governments are financially supporting variable renewable energy and storage projects in an effort to meet emissions reductions and renewable energy targets. If federal, state and territory governments are financially supporting investment in

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123 Frontier Economics, *Future Financial Risk-Management in the NEM,* p 22. See Attachment D.

124 Frontier Economics, *Future Financial Risk-Management in the NEM,* p 5. See Attachment D.

variable renewable energy and storage projects, they can deliver greater public benefit from their investment by increasing contract market liquidity, promoting more competition in retail markets.

Recommendation 4

Government-funded renewable energy projects should contribute to contract market liquidity

Governments can increase liquidity in the contract market during the transition by making more contracts available from government-supported renewable energy and storage projects.

To support retail competition, government-funded projects could support qualifying standalone and new-entrant retailers by providing priority access to a certain quantity of hedging contracts. This priority access recognises that standalone retailers are expected to face the largest challenges in hedging risk during the transition. Such a mechanism would require appropriate safeguards to ensure that access to contracts supports retail competition.

The role, timing and scale of other risk-management tools is unclear

In the long term, non-financial hedges, such as virtual power plants, customer-demand response and spot-price pass-through, are likely to become increasingly used by retailers as risk-management tools. Additional information on these options is provided in section 4.1.3. However, the extent to which they can displace some of the risk management covered by hedging contracts and/or vertical integration is uncertain, as is the timeframe over which they will become useful to small and new-entrant retailers.

As noted by Frontier Economics, emerging risk-management options such as virtual power plants and customer-demand response programs may be more useful to larger retailers than smaller retailers, as the risk mitigation they provide is more effective if spread over a high number of customers across multiple regions.

It is likely that with sufficient consumer uptake, these options could serve as a useful form of hedging for small and new-entrant retailers. However, this requires engagement from consumers, such as through buying rooftop solar, batteries, or an electric vehicle, or voluntarily reducing electricity use when prices are high. There is therefore significant uncertainty around how long it will take for these options to become well established and how widely they will ultimately be used.

Another alternative risk-management option to entering hedging contracts is for retailers to pass the risk onto consumers directly. This is known as spot-price (or pool-price) pass-through. Spot-price pass-through is currently used by a small number of small retailers. While this could continue to be a successful strategy for some retailers, there are only a limited number of customers that would be willing accept the risk of very high prices. Also, many consumers are unable to modify their electricity usage, which would make them very vulnerable on this type of offer. Spot-price pass-through is therefore not suitable for all customers and can only play a limited role in retailer risk management.[125]

As retailers diversify their risk management strategies to complement or replace their use of hedging contracts, it will be increasingly important to monitor the outcomes of these changes. As noted in Chapter 4, the Australian Energy Regulator’s wholesale market monitoring and reporting functions are in the process of being expanded. The Australian Energy Regulator’s expanded powers will improve the transparency of the contract market, but there will also be an increasing need for regulators and governments to consider the

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125 Frontier Economics, *Future Financial Risk-Management in the NEM,* p 24. See Attachment D.

risk-management needs of retailers holistically. Retailers may increasingly turn to non-financial risk-management options, such as investment in storage, virtual power plants and demand response. It will only be possible to assess how retailers are faring if their experience in the market and all risk-management options they use are considered.

Retailers' ability to manage financial risk should be considered in assessing, but not drive potential regulatory changes

In our stakeholder meetings we discussed potential regulatory changes that could be considered to support risk management, such as reducing the market price cap and the cumulative price threshold which would reduce the risk that retailers and customers are exposed to. This would reduce market signals for investment, which are an important element of the NEM's energy-only design.

Frontier Economics' report notes that implementing regulatory changes aimed at reducing price risk or volatility:

> …would substantially reduce the incentive for retailers to contract and for investment in essential dispatchable capacity, and this could further weaken the linkage between hedging and investment in supply options. In the NEM, being an energy-only market, generators rely on periods of price volatility and price spikes to recover their fixed costs. By capping prices, essential economic signals are removed and retailers will be less inclined to contract with generators to manage risk. These outcomes make it less attractive for generators to invest in the market. The absence of these price signals would therefore likely result in underinvestment. This resulting underinvestment would result in unreliability and this will likely result in even more market intervention.[126]

One example of government intervention noted by Frontier Economics is the Retailer Reliability Obligation, introduced in 2019. It requires retailers to purchase hedges when the reliability threshold is not met, to ensure firm supply. While retailers can contract with any form of generation, the firmer the contracted generation source, the greater its contribution will be to meeting a specific retailer's obligation.[127] The aim is to provide an incentive for market participants to invest in the right technologies in regions where it is needed, to support reliability in the NEM.[128] Further information on the Retailer Reliability Obligation is provided in Box 5.4.

We have not considered the effectiveness or the design of the Retailer Reliability Obligation. However, we acknowledge stakeholders' comments about the Retailer Reliability Obligation as outlined in Frontier Economics' report. We also note the Australian Energy Market Commission will conduct a review on the operational aspects of the Retailer Reliability Obligation by 2024.

126 Frontier Economics, *Future Financial Risk-Management in the NEM,* p 33. See Attachment D.

127 Department of the Environment and Energy, *Retailer Reliability Obligation factsheet*, Department of the Environment and Energy, Australian Government, 1 July 2019, accessed 6 November 2023.

128 Department of the Environment and Energy, *Retailer Reliability Obligation factsheet*.

Box 5.4 Retailer Reliability Obligation[129]

The Retailer Reliability Obligation aims to provide an additional incentive for market participants to invest in firm generation in regions where it is needed to support reliable electricity supply in the NEM. It is intended to be a long-term solution to ensuring reliability at the lowest cost by preparing for forecast reliability gaps well before they occur.

The Retailer Reliability Obligation requires retailers to enter sufficient qualifying financial contracts with dispatchable generation, storage or demand response to meet consumer and system needs when there is an identified forecast 'reliability gap' period. Those conditions are determined by AEMO, or in South Australia by the relevant Minister.

As discussed throughout this chapter, the current design of the NEM as a compulsory energy-only pool can mean that changes in the market affect retailers' ability to manage risk. Therefore, when policy makers consider regulatory changes for other reasons, they should be mindful of the likely impacts on standalone retailers' ability to manage financial risks. As the competition regulator, the ACCC considers any market interventions should be designed to facilitate competition, in both the wholesale and retail electricity markets, to the extent possible. Any interventions should be narrowly defined and tailored to address the specific market failure or issue.

The ACCC also recognises that regulatory uncertainty can impact efficient market outcomes. For example, when there is a real possibility of significant regulatory change, market participants may be less likely to offer long-term contracts which can result in higher costs and new entrants may be deterred from entering the market until the regulatory change is implemented and its impacts are better understood.

129 AEMC, *Terms of Reference – AEMC review of the retailer reliability obligation*, AEMC, Australian Government, 21 March 2023, date accessed 6 November 2023, pp 1-2.

Appendix A: Terms of reference

COMPETITION AND CONSUMER ACT 2010

INQUIRY INTO ELECTRICITY SUPPLY IN AUSTRALIA

I, Scott Morrison, Treasurer, pursuant to subsection 95H(1) of the *Competition and Consumer Act 2010*, hereby require the Australian Competition and Consumer Commission (ACCC) to hold an inquiry into prices, profits and margins in relation to the supply of electricity in the National Electricity Market.

Matters to be monitored and taken into consideration in the inquiry include but are not limited to:

i. electricity prices faced by customers in the National Energy Market including both the level and the spread of price offers, analysing how wholesale prices are influencing retail prices and whether any wholesale cost savings are being passed through to retail customers;
ii. wholesale market prices including the contributing factors to these such as input costs, bidding behaviour and any other relevant factors;
iii. the profits being made by electricity generators and retailers and the factors that have contributed to these;
iv. contract market liquidity, including assessing whether vertically integrated electricity suppliers are restricting competition and new entry; and
v. the effects of policy changes in the National Electricity Market, including those resulting from recommendations made by the ACCC in its Retail Electricity Pricing Inquiry report of July 2018.

Where appropriate, the inquiry will make recommendations to government(s) to take any proportional and targeted action considered necessary to remedy any failure by market participant(s) (or the market as a whole) to deliver competitive and efficient electricity prices for customers.

The ACCC should make use of publicly available information, including that published by the Australian Energy Regulator, the Australian Energy Market Commission or the Australian Energy Market Operator, where appropriate.

This is not to be an inquiry into supply by any particular person or persons, or by a State or Territory Authority.

The inquiry is to commence today. The inquiry is to provide its first report to me by 31 March 2019 and no less frequently than every six months thereafter. The first report should focus on setting out the analytical framework for monitoring and provide information about expectations of market outcomes and market participant behaviour. The inquiry should also provide information to the market as appropriate. The inquiry is to conclude and provide its final report by 31 August 2025.

DATED THIS 20th DAY OF August 2018

SCOTT MORRISON
Treasurer

Appendix B: Methodology for data collection and analysis

This appendix describes our methodology for collecting and analysing the data presented in this report. We describe our approach to data collection, quality assurance and our analytical methodology.

We collected 3 types of information compulsorily from market participants:

- ‘cost stack’ data, used to inform Chapter 2
- retail electricity pricing data and information, used to inform Chapter 3
- contract market data and information, used to inform Chapters 4 and 5.

We also substantiated these with other data sources, including publicly available retail offers (Section B.3).

In accordance with the terms of reference for the inquiry, we also make use of publicly available information published by market bodies. This appendix also describes our approach to collecting and analysing retail offer data reported to the Australian Energy Regulator and Essential Services Commission of Victoria.

B.1 Cost stack

Data collection

The ACCC used its compulsory information gathering powers to obtain cost stack data relating to the 2022–23 financial year from electricity retailers. These retailers provided electricity to about 84% of residential customers and about 81% of small and medium enterprise customers across the National Electricity Market (NEM) in 2022–23.[130]

Broadly, retailers were required to provide information on their revenue and usage, wholesale costs, network costs (transmission and distribution), environmental (green) scheme costs, and retail costs and margins. Various breakdowns of these categories were provided although not all retailers were able to provide the exact same sub-categories. We required retailers to state their cost to serve and cost to acquire and retain attributable to a number of pre-defined categories. These categories constitute the largest common retailer costs categories, based on our analysis of the 2017–18 retail operating costs data collected in our previous inquiry, the Retail Electricity Pricing Inquiry.

The ACCC sought information for 3 different customer types: residential, ‘small business’ customers (small and medium enterprise customers) and ‘large business’ customers (commercial and industrial customers).

Some retailers did not record certain categories of costs on a region-by-region basis or by customer type, and therefore applied allocation methodologies to estimate costs for these categories. For example, some of the difficulty in compiling a small business customer

130 AER, Retail energy market performance update for Quarter 2, 2022-23, AER, Australian Government, 15 March 2023, accessed 2 November 2023; ESC, Victorian Energy Market Report 2022-23 - Appendix: Retailer performance, ESC, Victorian Government, 30 June 2023, accessed 2 November 2023.

dataset using retailers' own information stems from some retailers not recording costs separately for residential and small business customers. Instead, these retailers record information for a combined group, commonly referred to as 'mass market'. In such cases, retailers were asked to apply an allocation methodology between residential and small business customers when reporting data to the ACCC. Where the retailer did not do this, we generally applied an allocation methodology ourselves. As noted in section 2.6.1, one retailer reported its data split by residential and small business customers for 2022–23, slightly impacting comparisons between 2022–23 results and previous years.

A number of retailers with generation assets provided information on their wholesale costs using a 'transfer price' methodology that reflected market prices for wholesale energy, rather than their actual generation costs. The transfer price methodology is not necessarily the same for each retailer. We have used these provided costs.

The results presented in charts exclude regional Queensland. Following improvements to our data collection, the Australian Capital Territory is included in New South Wales and NEM-wide data from 2019–20 onwards.

Quality assurance

The ACCC examined the returned data for inconsistencies and potential errors, and checked it against other data sources, such as public data from the Australian Energy Regulator. For example, we:

- checked that the number of residential customers, small business customers, large business customers and solar customers by retailer and region were consistent with our expectations based on customer numbers reported by the Australian Energy Regulator and the Essential Services Commission of Victoria[131]
- checked that retailers' data contained no unexpected data omissions
- queried individual retailers on any large or unexpected movements in their data relative to previous years.

Our checks identified several significant data quality issues for several retailers. In each case we contacted the retailers for clarification and in several instances updated data was provided. We repeated checks on any new data provided.

Analytical methodology

For our cost stack analysis, we used retailer margins (or more specifically, earnings before interest, tax, depreciation, and amortisation), cost and usage data to obtain measures of the total cost stacks for retailers.

For this report:

- A 'dollar per customer' measure was calculated by dividing revenue and costs by numbers of customers. This can be considered a proxy for the annual amount that an average customer would pay for electricity. However, it is only a general representation due to significant usage differences between geographic regions, time periods and customer types.

[131] AER, Retail energy market performance update for Quarter 2, 2022-23, AER, Australian Government, 15 March 2023, accessed 2 November 2023; ESC, Victorian Energy Market Report 2022-23 - Appendix: Retailer performance, ESC, Victorian Government, 30 June 2023, accessed 2 November 2023.

- A ‘cents per kilowatt hour’ measure was calculated by dividing revenue and costs by usage. This can be considered a proxy for the effective price faced by an electricity user for a unit of electricity. It does not account for usage differences between customers, which can vary dramatically. Retail tariffs are often structured with a fixed fee component, which, in this case, is averaged over the usage.
- Any cost stack data prior to 2017–18 was derived from data collected as part of our previous Retail Electricity Pricing Inquiry. This collection contains yearly data from 2007–08, 2010–11 and 2013–14 onwards.

In our cost stack analysis, our measure of the representative customer generally refers to the mean rather than the median. The distribution of residential electricity usage broadly follows a normal distribution, though it is positively skewed – that is, the average (mean) customer uses more than the median customer. This results from a small number of customers having much higher-than-average electricity usage.

For small business customers, there is a much larger range of electricity usage, and the distribution is not normal, reflecting the disparity in electricity requirements for small business activities. Care should be taken when interpreting small business data on a per-customer basis, because of the large range of underlying electricity consumption. Accordingly, we focus on a c/kWh measure for the small business cohort, which can more readily be scaled for different usage levels.

Unless otherwise stated, we have presented cost stack results using real (inflation adjusted) numbers, in 2022–23 dollars. NEM-wide charts are volume-weighted by usage or customer numbers, as relevant. The Goods and Services Tax (GST) is not included in the presented charts.

While the costs of premium feed-in tariffs are typically recovered through network charges, we have adjusted the data to attribute these costs to the ‘environmental’ cost category, rather than ‘network’ costs category. The premium feed-in tariff results presented for New South Wales include contributions to the New South Wales Climate Change Fund, which are recovered through network charges, like the costs of premium feed-in tariffs are in other regions. These results also include premium feed-in tariffs in the ACT from 2019–20.

Percentage values in charts may not sum to 100 due to rounding. Other values may similarly not sum due to rounding.

To convert nominal figures to real dollars, we adjust the figures using the ‘all groups; Australia’ consumer price index from the Australian Bureau of Statistics. Real dollars are as at June 2023.

B.2. Retail electricity prices

To inform Chapter 3, the ACCC obtained a new set of pricing data that has not previously been collected in this inquiry. We issued compulsory information gathering notices to 8 electricity retailers to collect retail prices of:

- all residential flat rate and flat rate with controlled load plans
- all small business flat rate plans.

Our sample of pricing data captures prices charged to approximately 5 million residential customers and 400,000 small business customers as at 1 August 2022 and 1 August 2023. The prices we collected included supply charges, usage charges, controlled load charges, solar feed-in tariffs, proportional conditional discounts, proportional unconditional (guaranteed) discounts and GreenPower charges.

While the pricing information collected does capture a significant portion of the market, our dataset only includes flat rate plans, and does not include plans that have cost reflective tariff structures such as time-of-use and demand plans. As reported in our June 2023 report, a growing number of customers are adopting cost-reflective electricity tariffs, with approximately 16% of residential customers in the NEM on cost-reflective tariffs in the 2021-22 financial year.

To complement and confirm our analysis of flat rate with or without controlled load offers, each retailer was also required to:

- report the proportions of customers paying more, equal to or less than the equivalent standing offer price by tariff type (including time-of-use) for each distribution region
- provide information about when they changed their prices, the proportion of customers affected, and the customer-weighted average change in price.

To create our solar analysis in Figure 3.7, we have excluded a minority of retailers who were not able to provide a breakdown of their plans by solar components due to the way in which their plan data is held.

Quality assurance

The ACCC examined the returned data for inconsistencies and potential errors. Our checks identified data quality issues for several retailers. In each case we contacted the retailers for clarification and in several instances updated data was provided. We repeated checks on any new data provided.

As noted above, due to differences in the way plan data is held, we excluded the solar data of a minority of retailers from Figure 3.7.

Analytical methodology

In order to conduct analysis of our pricing dataset, we calculated an annual cost that relies on the annual usage assumptions that are outlined in the 2022–23 and 2023–24 Default Market Offer and Victorian Default Offer determinations.

The usage assumptions are required because the pricing information collected is at a plan level and does not contain individual customer level usage information. As such, an assumption must be made on customer usage so that an annual price can be calculated. Usage assumptions also allow flat rate plans with differing usage charge block structures to be compared on a like-for-like basis.

Table B.1 below outlines the relevant usage assumptions that have been applied to our dataset for the purposes of calculating an annual price.

Table B.1 Default Market Offer and Victorian Default Offer usage assumptions

Usage assumptions by distribution region (kWh/year)

<table>
<tr><th rowspan="4">Distribution region</th><th colspan="4">2022</th><th colspan="4">2023</th></tr>
<tr><th colspan="3">Residential</th><th>Small business</th><th colspan="3">Residential</th><th>Small business</th></tr>
<tr><th rowspan="2">Flat rate</th><th colspan="2">Flat rate with controlled load</th><th rowspan="2">Flat rate</th><th rowspan="2">Flat rate</th><th colspan="2">Flat rate with controlled load</th><th rowspan="2">Flat rate</th></tr>
<tr><th>General usage</th><th>Controlled Load</th><th>General usage</th><th>Controlled Load</th></tr>
<tr><td>**Ausgrid**</td><td>3,900</td><td>4,800</td><td>2,000</td><td>10,000</td><td>3,911</td><td>4,813</td><td>2,005</td><td>10,027</td></tr>
<tr><td>**Endeavour Energy**</td><td>4,900</td><td>5,200</td><td>2,200</td><td>10,000</td><td>4,913</td><td>5,214</td><td>2,206</td><td>10,027</td></tr>
<tr><td>**Essential Energy**</td><td>4,600</td><td>4,600</td><td>1,900</td><td>10,000</td><td>4,613</td><td>4,613</td><td>1,905</td><td>10,027</td></tr>
<tr><td>**Energex**</td><td>4,600</td><td>4,400</td><td>2,000</td><td>10,000</td><td>4,613</td><td>4,412</td><td>2,005</td><td>10,027</td></tr>
<tr><td>**SA Power Networks**</td><td>4,000</td><td>4,200</td><td>1,800</td><td>10,000</td><td>4,011</td><td>4,212</td><td>1,805</td><td>10,027</td></tr>
<tr><td>**AusNet Services**</td><td rowspan="5">4,000</td><td rowspan="5">4,000</td><td rowspan="5">2,000</td><td rowspan="5">10,000</td><td rowspan="5">4,000</td><td rowspan="5">4,000</td><td rowspan="5">2,000</td><td rowspan="5">10,000</td></tr>
<tr><td>**CitiPower**</td></tr>
<tr><td>**Jemena**</td></tr>
<tr><td>**Powercor**</td></tr>
<tr><td>**United Energy**</td></tr>
</table>

Note: In the 2023-24 Victorian Default Offer determination, the Essential Services Commission of Victoria reported average annual bills for small business customers with annual usage of 10,000 kWh to align with how small businesses prices are reported in other states. The Essential Services Commission had previously used an average annual usage figure of 20,000 kWh for small businesses. To assist in the comparability of results across jurisdictions, an average usage amount of 10,000 kWh has been used for Victorian distribution regions in both 2022–23 and 2023–24

Using the usage assumptions in the default offer determinations also allowed us to compare the calculated annual cost to the annual costs determined under the Default Market Offer and Victorian Default Offer determinations.

In previous reports, including our June 2023 report, we have focused on comparing the bill outcomes for customers on standing offers to customers on market offers to explain the potential savings available to customers by moving from a standing offer to a market offer.

This analysis relied on our data set of 49 million customer bills. To make this comparison, we calculated 2 bills by multiplying the 95th percentile of median daily usage by the derived effective price for the median standing offer customer and the 25th percentile market offer customer.

While our analysis of bills and effective prices in previous reports demonstrated that customers could save by moving from a standing offer to a market offer, it did not examine the distribution of outcomes for market offer customers relative to the default offer prices.

Examining the relationship between usage and supply charges and annual cost

One of the potential limitations of comparing plans using a calculated annual cost (where prices are multiplied by an assumed usage) is that plans may appear more expensive or less expensive at different levels of usage depending on how the underlying prices are set.

For instance, a customer who uses a lot of electricity might save money by moving to a plan with a higher supply charge and lower usage charge. However, that plan might appear more expensive at a lower level of usage because the higher supply charge contributes more to the cost and is not offset by the lower usage charge.

The ACCC has previously examined the reliability of the percentage comparison to the Default Market Offer price in identifying cheaper offers across a range of usage levels. We found that it remained a reliable guide as to the value of an offer across a range of household sizes.[132]

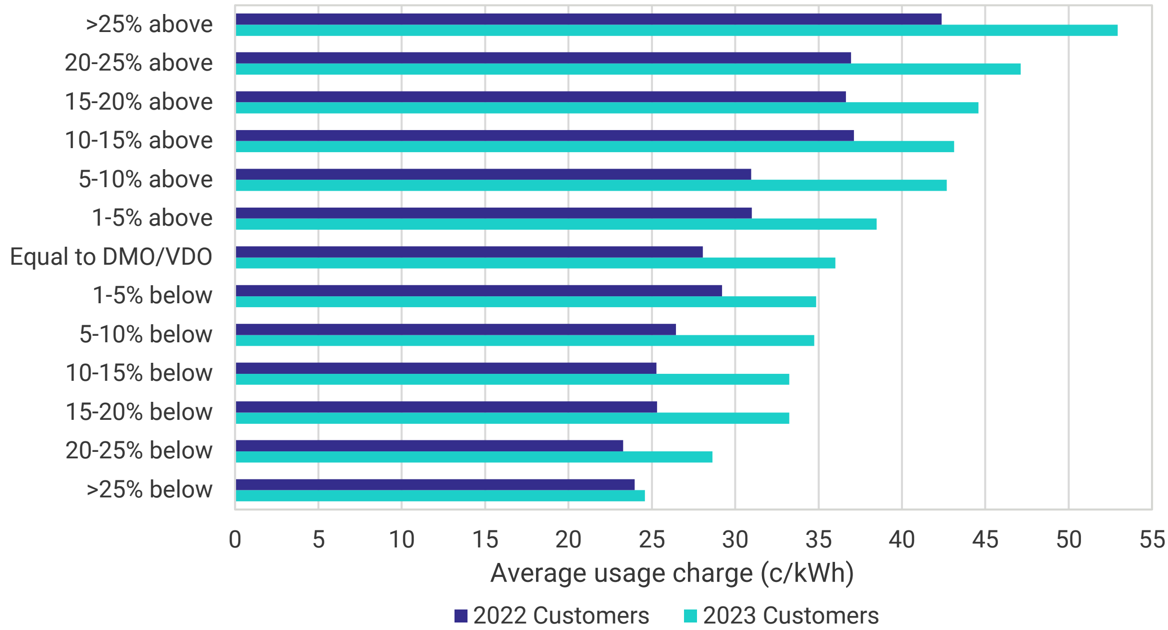
Similarly, our analysis of prices shows that the average daily supply charge does not change by much as the annual cost of an offer increases, while higher plan costs seem to be primarily driven by higher average usage charges.

This means that, regardless of the usage assumption employed, the plans we identify as higher priced compared to the Default Market Offer and Victorian Default Offer would remain expensive compared to other plans.

[132] ACCC, *Submission to the post-implementation review of the Electricity Retail Code consultation paper*, ACCC, Australian Government, 6 October 2021, p 11.

Figure B.1 Average usage charges increase with annual cost, while daily supply charges increase slightly across discount tiers

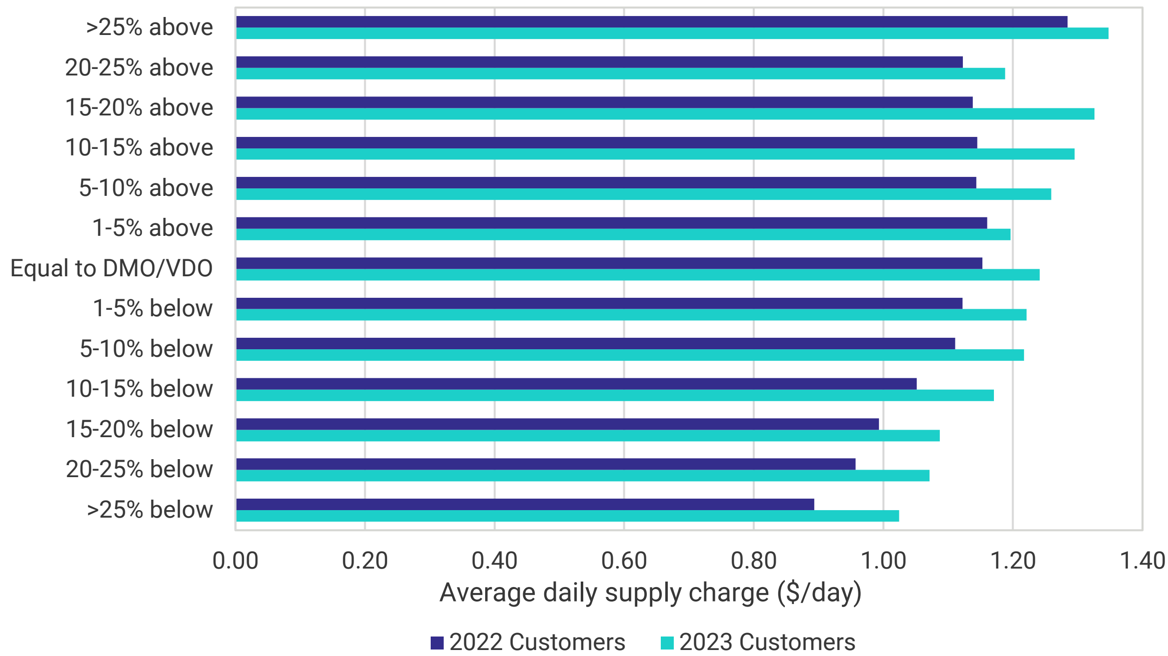
Average usage charge for residential flat rate and flat rate with controlled load market offer plans by discount tier to the DMO/VDO, all regions



Source: ACCC analysis of retailers' data.

Note: Average usage charges have been calculated using only the first usage block rate of each electricity plan. Some electricity plans have multiple block rates, whereby different unit rate prices are charged for different amounts of electricity usage.

Average supply charge for residential flat rate and flat rate with controlled load market offer plans by discount tier to the DMO/VDO, all regions



Source: ACCC analysis of retailers' data.

Conditional discounts

We have conducted separate annual price calculations on the basis that conditional discounts are both achieved and not achieved, and presented the differences in these results throughout the chapter and in the data appendix where relevant.

For annual prices calculated with conditional discounts, we have assumed that conditional discounts are achieved with 100% success, and that these are applied to the total annual bill. We note that in our June 2023 report, we found that, as at 1 July 2022, 9% of residential customers and 15% of small business customers failed to achieve their conditional discounts (of the 20% of customers who receive a conditional discount).

B.3. Publicly available retail offers

Data collection

In this report, we included analysis that estimates changes in retail electricity prices from September 2020 to September 2023 (see Figure 3.10). These estimates are based on electricity offers from retailers that were publicly available on government comparator websites:

- Energy Made Easy, which is run by the Australian Energy Regulator and covers New South Wales, Queensland, South Australia, Tasmania, and the Australian Capital Territory
- Victorian Energy Compare, which is run by the Essential Services Commission of Victoria.

All retailers must upload the particular details of their electricity offers (both standing offers and market offers) for residential and small business customers to these sites. We collected offer data at the beginning of every month,[133] obtaining key information on each plan such as customer type, region, tariff type and solar status, as well as the price of the offer and charging basis.

Analytical methodology

To calculate estimated median annual bills, we combined market offer information with benchmark consumption figures. For residential households, these were specified for each distribution zone; for small businesses we used a consistent 20 kWh estimate across all regions. See Table B1.

This produces an illustrative estimate of annual bills, but there are some limitations. For example, this approach only reflects prices for customers entering new contracts, not existing customers (in contrast to our retail pricing dataset outlined above). We also filtered the calculation to single rate tariffs. While this is the most common type of tariff, there are other tariffs in use, such as time of use tariffs, that are not covered in this dataset.

In Figure 3.10, we plotted the annual bill of the median offer to illustrate the central value of publicly available offer prices. We also plotted the estimated annual bill of the standing offer in each state for comparison purposes.

133 The exception was the months of November and December 2020, when only a subset of the required data was collected. For charts in the body of the report, we have modelled replacement figures based on the available data.

B.4. Contract market

Data collection

The ACCC used its compulsory information gathering powers to obtain information relating to the contract market from 21 current electricity retailers, generators and gentailers. This is 2 fewer companies than for our November 2022 report. These market participants account for the vast majority of the electricity contracts traded in the NEM.

Retailers provided data relating to all hedging contracts they traded between 24 August 2022 and 19 July 2023. This included the following information about each trade:

- strike price and any premium or other costs
- date of trade
- start and end dates of the contract delivery period
- volume of the trade (if fixed)
- volume shape and time of day that apply to the contract
- type of contract
- counterparties
- whether the contract was traded on ASX, FEX, or over the counter
- whether the contract was a result of an option being exercised
- for options, whether they were put or call, and the type of option
- whether the counterparty was related to the company
- qualitative descriptions of all of the above information categories for bespoke contracts.

In addition to the comprehensive trade data we collected, we also required the market participants to fill out a qualitative survey, with questions relating to a wide variety of contract market issues. Themes for these questions included:

- access to hedging contracts on the ASX
- access to hedging contracts over the counter
- access to hedging contracts on FEX
- margin requirements and credit support
- AEMO prudential requirements
- general risk management and hedging strategy
- the impact of contract market issues on retail competition
- the future of the contract market.

In general, the questions asked participants how strongly they agreed with certain statements or how significant certain factors were, in relation to the above topics. We asked slightly different questions to participants depending on their size and role in the market, as we considered that some issues were likely to affect small retailers and larger generators and gentailers differently.

Quality assurance

We checked each participant's data for likely errors. This included searching for common types of errors such as negative values, missing data, and statistical outliers. It also included internal consistency checks with data that participants provided us in previous information requests, as well as external checks against public data sources such as ASX trade data.

We identified several data errors through this process. We contacted retailers and generators for clarification and requested that the data be resubmitted where necessary.

Analytical methodology

All contract market analysis incorporated ASX, FEX and OTC trade data, unless otherwise stated. We also did not include any internal trades in our analysis unless otherwise stated.

Most of our analysis was performed on either purchases or sales only. Where both purchases and sales were included, they were clearly separated. This was to avoid double counting, as in many cases we collected the same data twice. That is, we received it from both parties that entered into the contract.

When analysing prices paid over-the-counter compared with on the ASX, we were careful to make like-for-like comparisons. We did this by only comparing prices for the same type of product, traded on the same day and in the same region. The same approach was applied when comparing prices paid by small retailers to those paid by larger generators and gentailers.

For our analysis of price trends, we were careful to only include like products in the analysis. We excluded trades that were the result of an option being exercised in our price analysis, as these contracts were effectively bought at different time periods under different market conditions.

Our volume trend analysis did include trades that were the result of options being exercised. However, contracts where the volume ultimately traded was uncertain, such as caps, options that were not yet exercised, weather derivatives, and load following swaps, were not included in the analysis.

For our average delivery-period analysis (Figure 4.4), we calculated the average delivery-period start date for all trades and the average delivery-period end date for all trades. We then subtracted the date of trade from these values to get an indicative future period covered by the 'average contract'.