Wholesale electricity costs for 2023/24

A draft report for the Essential Services Commission | 10 March 2023

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1 Introduction

Frontier Economics has been engaged to advise the Essential Services Commission (ESC) on allowances for wholesale electricity costs for financial year 2023/24 for retailing electricity to small customers, for the purposes of determining the Victorian Default Offer (VDO).

1.1 Background

The ESC is required to determine prices for the VDO to apply from 1 July 2023. To inform this the ESC needs forecasts of retailers' wholesale electricity costs and of retailers' costs of complying with environmental programs for financial year 2023/24.

1.2 Frontier Economics' engagement

Frontier Economics has been engaged by the ESC to provide advice on two aspects of the VDO:

- The wholesale electricity cost (WEC) component of retailers' cost to supply small customers from 1 July 2023.
- The retailers' costs of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) in supplying small customers from 1 July 2023.

1.3 This draft report

This draft report sets out our draft advice to the ESC on the WEC and costs of complying with the LRET and the SRES, for retailers in each of the five Victorian distribution network areas. This report is structured as follows:

- Section 2 provides an overview of the approach used to estimate wholesale energy costs.
- Section 3 discusses the half-hourly prices and half-hourly load used in our analysis.
- Section 4 discusses the contract prices used in our analysis.
- Section 5 discusses the contract position used in our analysis.
- Section 6 provides our estimate of the WEC.
- Section 7 provides our estimates of the costs of complying with the LRET and SRES.

In addition to this report, we also provide spreadsheets setting out details of half-hourly load and price forecasts, contract positions resulting from our modelling, and calculations for determining the WEC.

1.4 Previous advice to the ESC

Frontier Economics has previously advised the ESC on the WEC and the cost of complying with the LRET and the SRES for financial year 2019/20, for calendar years 2020, 2021 and 2022, and for financial year 2022/23.[1]

This report for financial year 2023/24 adopts substantially the same approach for estimating WEC and the costs of complying with the LRET and the SRES as we adopted previously. We note that for this report we develop estimates of half-hourly prices and half-hourly load using only the three most recent years of historical data. This is the same approach we took for the 2022/23 VDO, while in our previous work we developed estimates of half-hourly prices and half-hourly load using all available historical data (which at the time of the latest of these reports – for calendar year 2022 – consisted of five years of historical data). We have made this change in approach because of the evidence of changing trends in patterns of half-hourly prices and half-hourly load.

1 See, for example: Frontier Economics, *Wholesale Electricity Costs for 2022*, A final report for the Essential Services Commission, 22 October 2021. Available on the ESC's website: https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer/victorian-default-offer-price-review-1-january-2022#tabs-container2

2 Approach to assessing WEC

Under the settlement rules in the National Electricity Market (NEM), retailers are responsible for purchasing electricity to meet the load of their customers in the wholesale electricity market. A retailer will pay, for each half hour (or for each five minute period, since the introduction of five minute settlement), its customer's electricity load in that interval multiplied by the relevant regional reference price from the wholesale electricity spot market for that interval. For customers in Victoria, the relevant regional reference price is the Victorian regional reference price.

These settlement payments that retailers face can be extremely volatile. Electricity load for small customers can vary significantly from one interval to the next, and electricity spot prices can be anywhere between the Market Price Cap (which for 2022/23 is $15,500/MWh) and the market floor price (which is -$1,000/MWh). Since retailers will typically commit to supply their customers at a specified retail price for a period of time, this volatility in settlement payments can result in retailers paying more for electricity than they receive for that electricity through the retail price they have agreed with their customers. At worst, this exposes the retailers to the risk of financial failure.

To manage the risks associated with volatile load and spot prices, retailers will typically seek to hedge their exposure to spot prices by entering into hedging arrangements. There are several ways that retailers can hedge their exposure to spot prices. The most common are the following:

- Vertical integration through ownership of an electricity generator. A retailer that owns a generator has what is known as a natural hedge: when the spot price is high, the retailer will have to pay the high spot price for its customer's load but, as the owner of a generator, will also receive the high spot price for its electricity generation.
- Power purchase agreements with a generator. Power purchase agreements provide a similar hedging benefit to vertical integration, but they do so through contractual arrangements between a retailer and a generator, rather than through ownership.
- Financial derivatives. There are a range of financial derivatives that are available to retailers (and generators) to hedge their exposure to volatile spot prices. Common contracts include swap contracts (which effectively lock-in a spot price for the counterparties) and cap contracts (which effectively cap the spot price for a retailer). These are traded both on the stock exchange and over-the-counter between participants.

Retailers' energy purchase costs are typically taken to be the average cost to a retailer of purchasing electricity from the wholesale market for its customers, taking into account both the retailer's settlement payments to the Australian Energy Market Operator (AEMO) and the financial outcomes from the retailer's hedging arrangements.

Regulatory practice in Australia has typically focused on estimating the energy purchase cost for a benchmark retailer. In doing so, regulators have typically assumed that the benchmark retailer will make use of exchange-traded financial derivatives to hedge its exposure to spot prices. The assumption that a benchmark retailer will use exchange-traded financial derivatives is typically based on the following reasoning:

- Any retailer of a reasonable size should be able to hedge its exposure to wholesale spot prices using exchange-traded financial derivatives, while vertical integration and entering power purchase agreements can be impractical for retailers with a smaller retail position in a market or with a less certain retail position.
- Prices for exchange-traded financial derivatives are transparent since they are traded on the ASX. In contrast, the costs of building generation plant or entering into power purchase agreements is less transparent.

In practice, retailers in the NEM do adopt a mix of hedging strategies, including vertical integration and power purchase agreements and purchasing over-the-counter (OTC) hedging contracts, which are traded through brokers not on the ASX. Retailers will presumably vertically integrate or enter into power purchase agreements because they think these strategies offer advantages that financial derivatives cannot; by excluding vertical integration and power purchase agreements from consideration, therefore, regulators will, if anything, tend to overstate the costs that retailers will face, or understate the risk management that retailers can achieve.

We follow this typical approach of assessing the WEC that retailers face based on an estimate of the cost that a prudent retailer would face in supplying electricity to their customers, having regard to the hedging contracts that a prudent retailer is likely to enter into. The hedging contracts that we base this analysis on are quarterly base swaps, peak swaps and base caps, traded on ASXEnergy.

To estimate WEC in this way, we need to answer four questions:

- What is the expected half-hourly load of the retailer’s customers?
- What are the expected half-hourly spot prices that retailers will face?
- What is the cost of financial hedging contracts?
- What kind of hedging position is a prudent retailer likely to adopt?

From the answers to these questions, we can calculate the WEC that a retailer would face.

We address these questions in the sections that follow.

3 Half-hourly spot prices and half-hourly load

This section addresses the first two questions we need to answer to estimate WEC:

- What is the expected half-hourly load of the retailers' customers?
- What are the expected half-hourly spot prices that retailers will face?

We deal with these questions together because we believe it is important to forecast half-hourly spot prices and half-hourly load in a way that accounts for the correlation between prices and load. After all, this correlation is a key driver of the risks that retailers face.

3.1 Historical data on half-hourly price and load

Our modelling of the WEC requires projections of half-hourly spot prices in Victoria and customer load to be supplied by retailers in Victoria.

In our view, the best source of data about half-hourly patterns of spot prices, half-hourly patterns of customer load, and the correlation between the two, is historical data. The historical data on prices and load will reflect all the complex factors that drive both spot prices and customer load, and the interactions between them, which are difficult to accurately capture at the half-hourly level using forecasting models. These historical data on prices and load can then be scaled to account for any trends in prices and load over the forecast period.

Impact of five minute settlement

With the change to five minute settlement in 1 October 2021, it would be best to use historical five minute spot price and load data for the analysis of this report. This would allow us to best estimate the costs and risks associated with a retailer meeting their customers' load in the NEM in 2023/24.

However, at this point the load data that is provided to the ESC by AEMO is half-hourly data, so we continue to make use of half-hourly prices and load.

Thus, the historical data that we use is:

- For prices, the half-hourly spot prices for the Victorian regional reference node, as published by AEMO.
- For customer load, half-hourly load data that AEMO has directly provided to the ESC on customers with annual consumption less than 40MWh for each of the five distribution network areas in Victoria. AEMO has provided separate half-hourly load data for residential customers with annual consumption less than 40MWh and for business customers with annual consumption less than 40MWh.

We use this data directly provided by AEMO because it closely coincides with the customer groups to which the VDO will apply:

- For residential customers, the VDO will apply to all residential customers. The data provided by AEMO is only for residential customers with annual consumption less than 40MWh, but since very few residential customers will have annual consumption greater than 40MWh this is unlikely to make a material difference to the estimated WEC.
- For small business customers, the VDO will apply to small business customers, with small business customers defined as customers with aggregate consumption less than 40 MWh per annum. The data provided by AEMO aligns with the applicability of the VDO.

In contrast, the Manually Read Interval Meter (MRIM) data that is publicly available from AEMO includes aggregated half-hour electricity consumption for all type 5 meters in each of the five distribution network areas in Victoria. This includes a mix of residential and business customers with annual consumption up to 160MWh.

3.2 Selecting appropriate historical data

When using historical data on prices and load in this way, a useful starting point is to choose data on prices and load from an historical period that we think is likely to be most consistent with the forecast period. For example, the closure of coal-fired power stations may have substantial impacts on price levels and volatility. Likewise, the increasing adoption of rooftop solar PV is likely to materially affect load factors and prices over time.

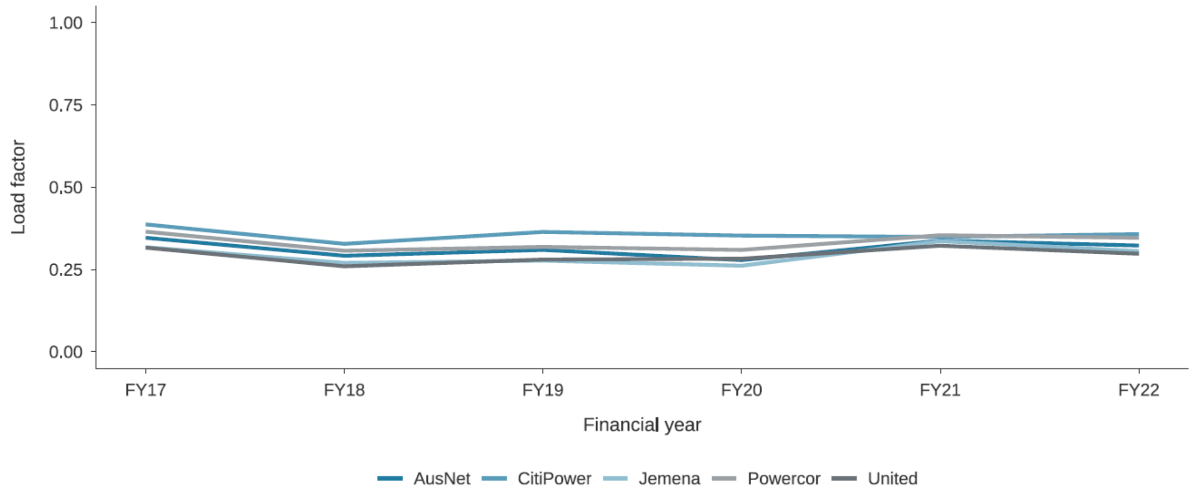
The load data that is directly provided by AEMO is from 1 July 2016 to 30 June 2022 – a period of 6 years.

Analysis of data

Figure 1 shows the annual load factor for the residential data for each Victorian DNSP for the last six financial years. From this figure we can see that there is some variability over time in the residential load factor, but in our view there is not a clear trend towards a significantly higher or lower load factor over time.

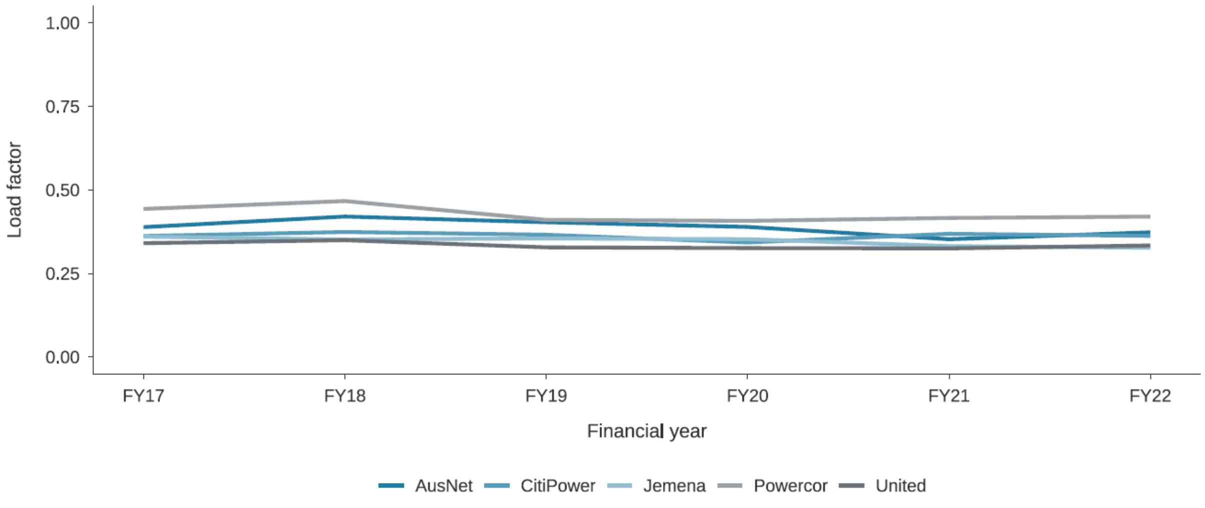
Figure 2 shows the annual load factor for the business data for each Victorian DNSP for the last six financial years, on the same basis as the residential load factor. As with the residential load factor, we can see some variability over time in the business load factor. However, as with the residential load factor, in our view there is not a clear trend towards a significantly higher or lower load factor over time.

Figure 1: Load factor for residential customers



Source: Frontier Economics analysis of AEMO data

Figure 2: Load factor for business customers



Source: Frontier Economics analysis of AEMO data

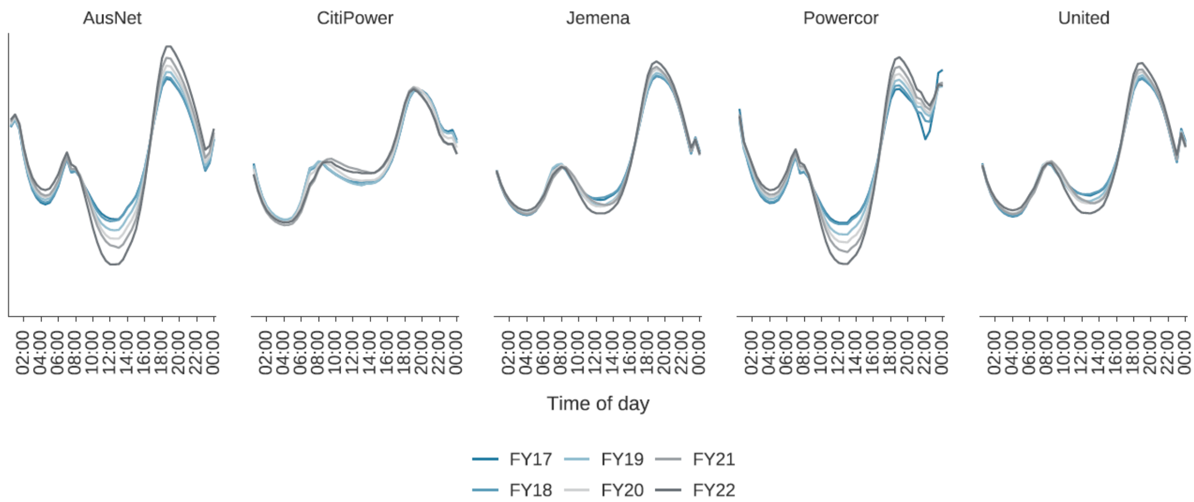
Figure 3 and **Figure 4** show the average daily profile for residential and business customers respectively for each Victorian DNSP for the last six financial years, normalised to the same annual consumption to highlight differences in the timing of daily consumption.

As we discussed in our report for the 2022/23 VDO, in our view, this data increasingly suggests that average daily profiles for both residential and business customers are changing.

For residential customers, we can see that 2021/22 had the lowest relative consumption during the day, and the highest relative consumption during the early evening, for most of the Victorian DNSPs. Furthermore, for most of the Victorian DNSPs, we can see that the last 3 financial years have tended to show a similar pattern, with relatively lower consumption during the day and relatively higher consumption during the early evening, compared to earlier years.

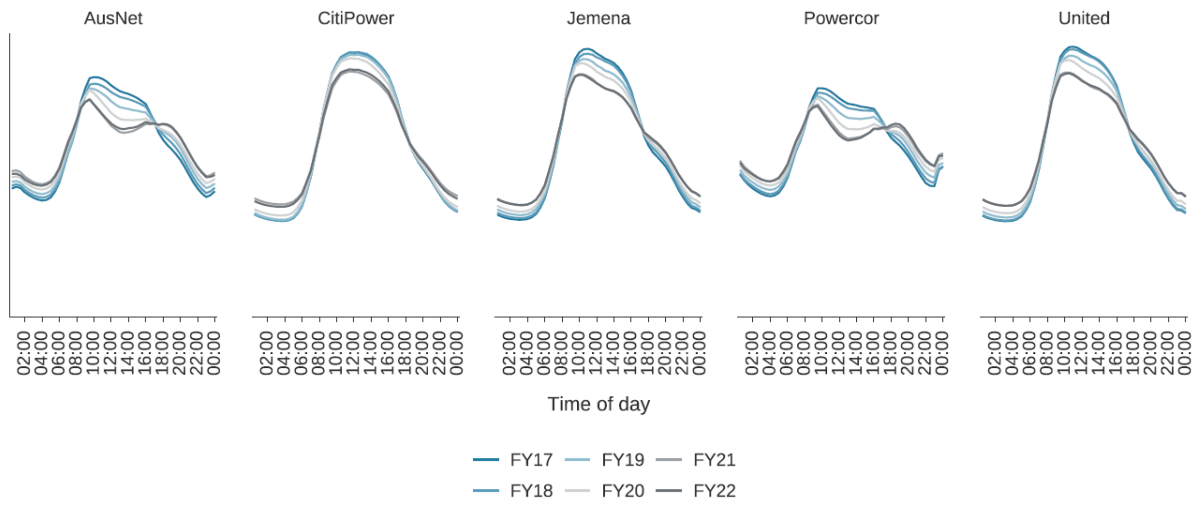
For business customers, we can see a similar pattern in the last three financial years, with relatively lower consumption during the day and higher consumption at other times than. If anything, this pattern is more consistent across the Victorian DNSPs for business customers than it is for residential customers.

Figure 3: Average daily profile for residential customers



Source: Frontier Economics analysis of AEMO data

Figure 4: Average daily profile for business customers



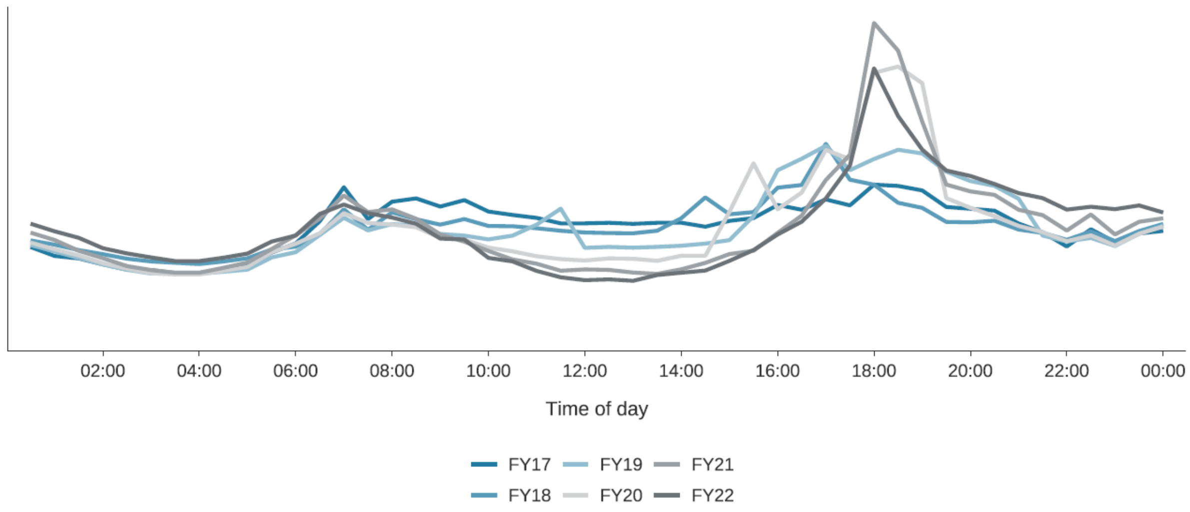
Source: Frontier Economics analysis of AEMO data

Figure 5 shows the average daily profile for Victorian spot prices for the last six financial years, normalised to the same average annual price to highlight differences in the timing of daily prices.

It is no surprise to see that there is greater variability in daily patterns of spot prices than there is in daily patterns of customer load. However, despite this variability, in each year we do see similar patterns of low overnight prices, a price spike tending to occur in the morning, and further high prices tending to occur in the mid-afternoon to evening.

The daily profiles for the last three financial years are the most similar to each other, with relative prices during the day that are materially lower, and relative prices during the evening that are materially higher.

Figure 5: Average daily profile for Victorian spot prices



Source: Frontier Economics analysis of AEMO data

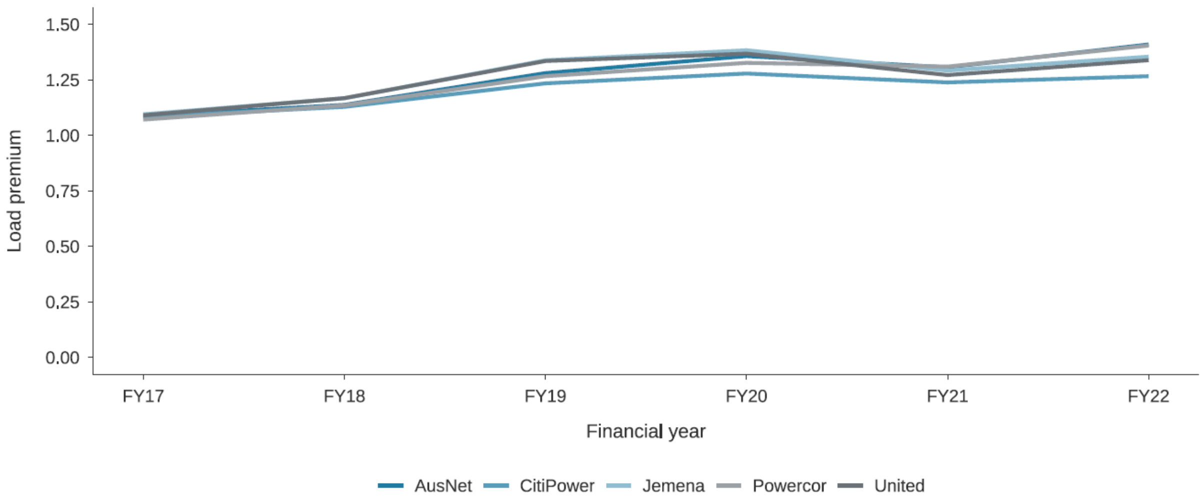
Figure 6 and **Figure 7** combine the historical customer load data and spot price data to report the load premium (calculated as the load-weighted price divided by the time-weighted price) for each customer type, for each Victorian DNSP and for each of the last six financial years.

In our experience, the load-weighted spot price (and, by extension, the load premium) is a reasonable guide to the WEC.

We can see from **Figure 6** that for residential customers the load premium for three or four financial years was materially higher than it had been previously. This is largely because of spot prices remaining higher for longer in the early evening, but also because load has tended to be relatively higher in the evening.

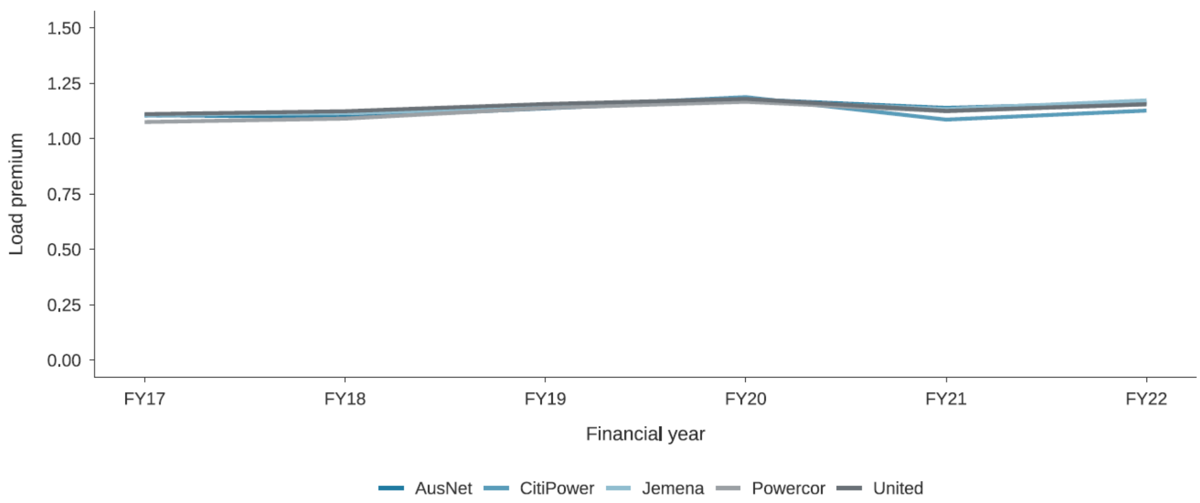
We can see from **Figure 7** that for business customers the load premium for the last 3 or four financial years is also higher than previous years, although the difference is smaller than it is for residential customers.

Figure 6: Load premium for residential customers, based on Victorian spot prices



Source: Frontier Economics analysis of AEMO data

Figure 7: Load premium for business customers, based on Victorian spot prices



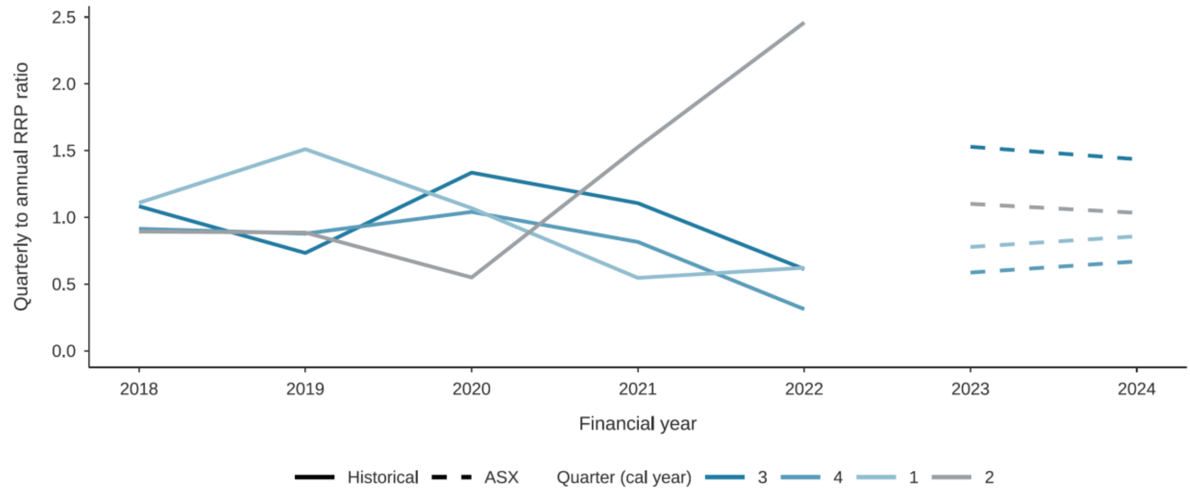
Source: Frontier Economics analysis of AEMO data

As well as examining historical data it can be useful to compare historical price outcomes with expectations of future prices, based on ASXEnergy contract prices. Since we will ultimately be scaling historical half-hourly prices to an average price based on ASXEnergy contract prices, it is helpful if the historical patterns in half-hourly prices are reasonably consistent with the pricing outcomes indicated by ASXEnergy contract prices.

Figure 8 examines quarterly patterns of spot prices and ASXEnergy prices. For each quarter, **Figure 8** presents the relationship between average quarterly prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swap prices for Victoria. **Figure 8** reveals quite a degree of volatility in the relationship between quarterly prices over time. However, some trends in the historical data are apparent, and are carried through to the ASXEnergy data. For instance, over time Q1 has changed from tending to have prices that are amongst the highest of any quarter to tending to have prices that are among the lowest of any quarter. This is reflected in the ASXEnergy data, with Q1 prices towards the lower end. Similarly, Q2 and Q3 prices have shifted toward being higher over the last few years, and this is also reflected in the ASXEnergy data. The historical data for 2022 is clearly affected by the high price events in Q2 2022, with prices in that quarter being significantly higher than any other quarter in financial year 2021/22. In our view, **Figure 8** suggests that quarterly patterns of spot prices over the last 3 financial years are more consistent with the ASXEnergy data than are quarterly patterns of spot prices from the earlier years.

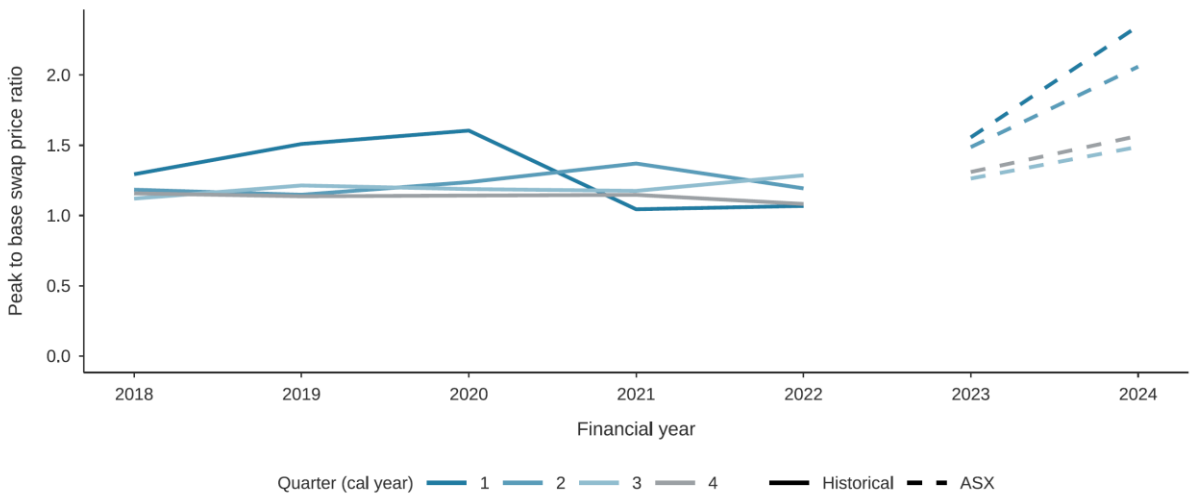
Figure 9 examines peak/off-peak patterns of spot prices and ASXEnergy prices. For each peak/off-peak period, **Figure 9** presents the relationship between average peak/off-peak prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swaps prices for Victoria. **Figure 9** shows that for the last few years there has been a relatively consistent relationship between peak and off-peak prices across the quarters, with peak prices being at a moderate premium to base prices. This is relatively consistent with the ASXEnergy data for Q3 and Q4 2023. However, the ASXEnergy data for Q1 and Q2 2024 reveals a much higher premium for peak prices relative to base prices. This reflects the fact that peak prices for these quarters have not yet fallen in line with recent reductions in other contract prices. We note, however, that more recent prices, since this analysis was undertaken, show a reduction in peak prices for Q1 2024. We will continue to monitor these prices leading up to our final report.

Figure 8: Quarterly patterns of spot prices and ASXEnergy prices



Source: Frontier Economics analysis of AEMO data and ASXEnergy data

Figure 9: Peak/off-peak patterns of spot prices and ASXEnergy prices



Source: Frontier Economics analysis of AEMO data and ASXEnergy data

Based on the analysis of historical half-hourly load and half-hourly prices set out above, our approach for this report is to limit the data we include in our analysis to the 3 most recent financial years: 2019/20, 2020/21 and 2021/22. That is, we include data only from these three years in a Monte Carlo simulation when forecasting half-hourly load and half-hourly prices.

This is consistent with the approach we took for the 2022/23 VDO, for which we also used the most recent 3 years that were available at the time. The reason for this is the increasing evidence that patterns of load and patterns of prices are exhibiting a trend, with load and prices both tending to be lower during the day.

3.3 Projecting half-hourly load and spot prices

As discussed, rather than take a single one of the years from 2019/20 to 2021/22 as representative of outcomes in 2023/24, we perform a Monte Carlo simulation on the three years of half-hourly load and price data. In our view there are two benefits of using a Monte Carlo analysis:

- Any single year will be subject to unique market conditions that are unlikely to be repeated. This creates the risk that any single year may not be representative of conditions that might be expected in the future. However, using a Monte Carlo approach based, in this case, on three years of data increases the likelihood of basing our analysis on a representative set of conditions.
- Using a Monte Carlo analysis allows us to create a distribution of market conditions, providing some insight into the expected distribution of the WEC.

The Monte Carlo simulation is used to generate a year of half-hourly data by randomly drawing one day of data, from the pool of available historical days, for each day of the forecast year. This random drawing of data is done from a pool of like days (where days are classified according to day type – weekday/weekend – and quarter). The Monte Carlo simulation is then performed 500 times to get a distribution of simulated years, which allows us to choose a simulated year from within this distribution to use in the modelling.

For example, a single simulated year will be generated as follows:

- The first day of 2023/24 is 1 July 2023, which is a Saturday. Since this is a Saturday in Q3, the half-hourly load and spot data for the first day of 2023/24 will be determined by randomly drawing a day's half-hourly data from all the Q3 weekend days that occurred in 2019/20 through to 2021/22.
- The second day of 2023/24 is 2 July 2022, which is a Sunday. Since this is a Sunday in Q3, the half-hourly load and spot data for the second day of 2023/24 will be determined by randomly drawing a day's half-hourly data from all the Q3 weekend days that occurred in 2019/20 to 2021/22.
- And so on for the 365 days that make up 2023/24, having regard, for each day, to its type and its quarter.

This process is then repeated 500 times to generate 500 simulated years, each year made up entirely of historical outcomes in 2019/20 through to 2021/22.

For each of these simulated years, load and prices are drawn at the same time (i.e. from the same historical day) so that the correlation between load and prices is maintained.

Once we have completed this Monte Carlo simulation, we make a last adjustment to the consumption data, normalising each of the simulated years to 1 GWh of annual consumption. This maintains the load shape and correlation between load and prices, but each year now has a uniform annual consumption.

We also make a further adjustment to the half-hourly spot prices. We consider that historical half-hourly spot prices provide the best source of information about patterns of half-hourly spot prices and how these are correlated with half-hourly load, but historical spot prices are not necessarily a good predictor of the future average level of Victorian spot prices. There is no reason, for instance, that Victorian spot prices over 2019/20 through to 2021/22 will, on average, be the same as Victorian spot prices for 2023/24. In our view, the best available public information about the average level of Victorian spot prices for 2023/24 is the contract prices published by ASXEnergy. These contract prices – particularly the prices of base swaps – provide the market's view on what will be the average spot price for 2023/24. Given this, for each simulated year, we assume that the average level of prices is consistent with ASXEnergy futures prices. Specifically, for each simulated year we scale the half-hourly prices so that the time-weighted average price in each quarter is equal to the relevant quarterly base swap prices for 2023/24 from ASXEnergy[2] (less an assumed contract premium of 5 per cent on the underlying prices). We use the 40-day average of ASXEnergy contract prices for quarterly base swap prices (up to 10 January 2023) as representing the market's current view of spot prices for each quarter of 2023/24.[3] This approach to generating half-hourly price forecasts results in:

- The appropriate average level of spot prices (i.e. the time-weighted quarterly average price is consistent with ASXEnergy prices).
- The appropriate half-hourly profile of spot prices (i.e. the half-hourly profile of prices, and load, are consistent with historical outcomes).

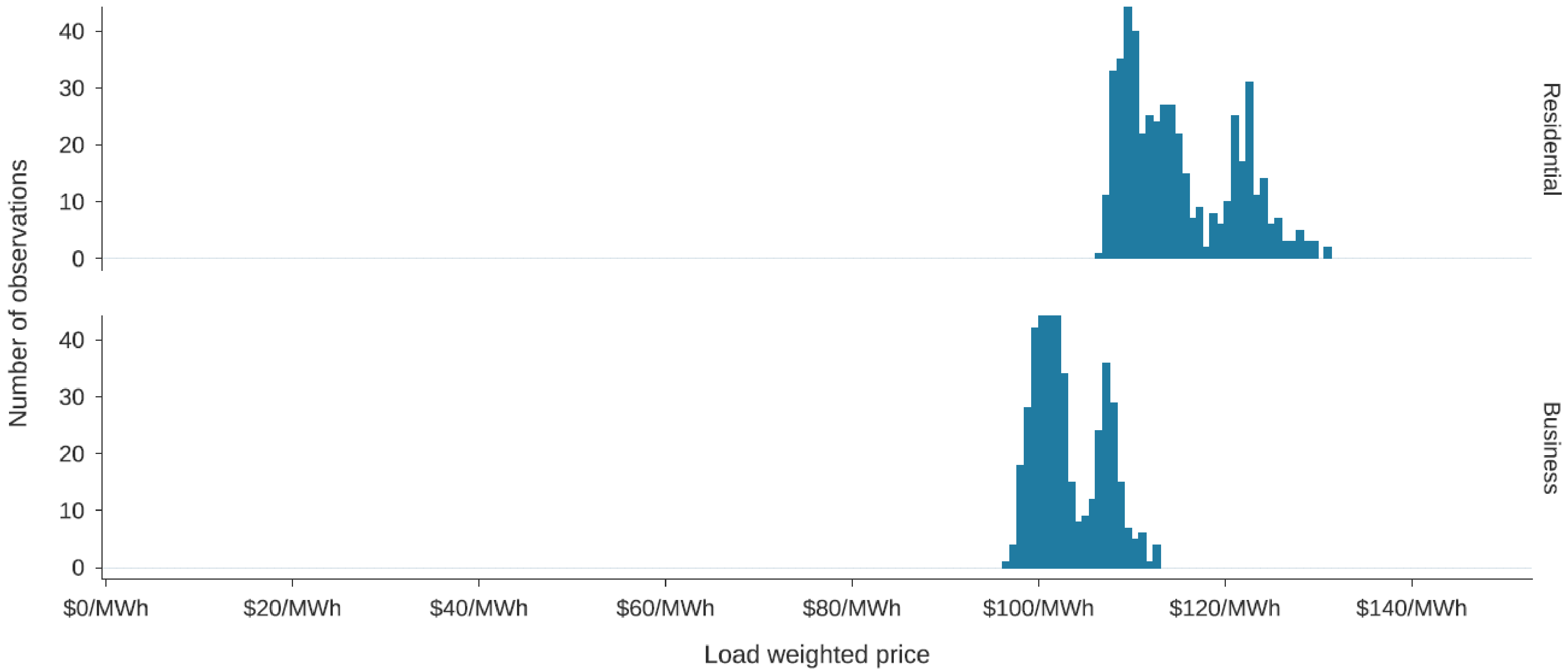
Analysis of data

An indication of the results of our Monte Carlo simulation can be provided by calculating the load-weighted price for each of the 500 simulated years. As we discussed, in our experience the load-weighted price is a reasonable guide to the WEC. **Figure 10** through **Figure 14** show the distribution of load-weighted prices for each of the 500 simulated years from our Monte Carlo analysis, for each distribution area and for each customer type. As discussed, the average spot price in each of these simulated years is the same – based on the 40-day average ASXEnergy base swap price – but the half-hourly profile of both spot prices and load are different. It should be clear from **Figure 10** through **Figure 14** that the Monte Carlo simulation has resulted in a distribution of load-weighted prices driven by differences in the half-hourly patterns of spot prices and load.

2 An alternative approach would be to attempt to scale half-hourly prices having regard to each of base swaps, peak swaps and cap prices. However, the scaling process would require subjective judgements about how to simultaneously scale to each of these prices. Given there would be little on which to base these subjective judgements our preference is to scale only to base swap prices, which is a mechanical process. We note, however, that the calculation of the WEC does use each of the contract prices from ASXEnergy.

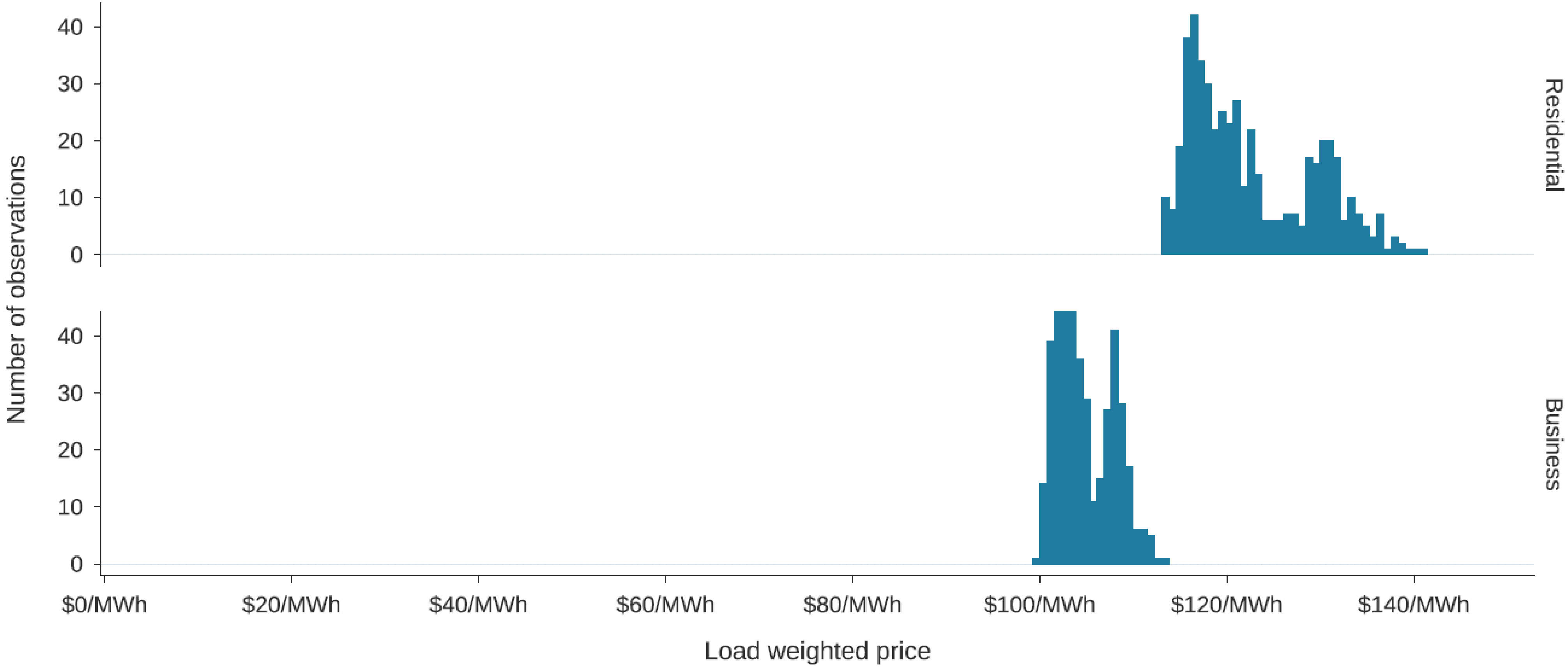
3 We note that there is a difference in the averaging period that we use for estimating spot prices for 2023/24 and the averaging period we use for calculating contract prices to be used in estimating the WEC for the VDO. As discussed, we use the most recent 40-day average ASXEnergy prices as the best guide to the market's view on spot prices that will occur in 2023/24. However, based on instructions from the ESC, we use 12-month trade weighted average ASXEnergy prices to set the contract price for retailers when determining the WEC. In our view, there is no necessity for these averaging periods to be consistent. One way to think about the WEC that we are calculating using this approach is that we are estimating the contract payments that a retailer would face if that retailer had purchased its contracts for 2023/24 over the last 12 months (at the same time as trade occurs on ASXEnergy) and uses those contracts to hedge the risk it would face based on current expectations of spot prices.

Figure 10: Distribution of load-weighted price for simulated years for residential and business load – CitiPower



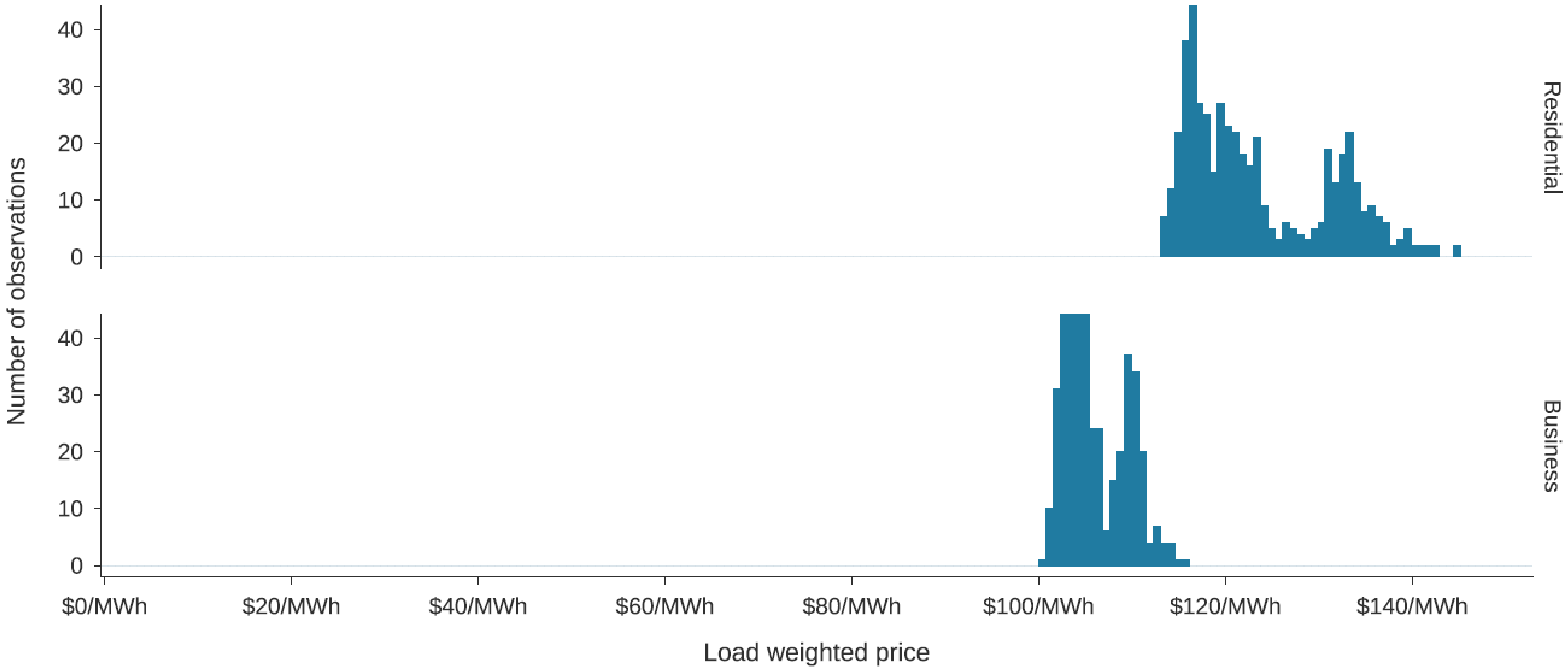
Source: Frontier Economics

Figure 11: Distribution of load-weighted price for simulated years for residential and business load – Powercor



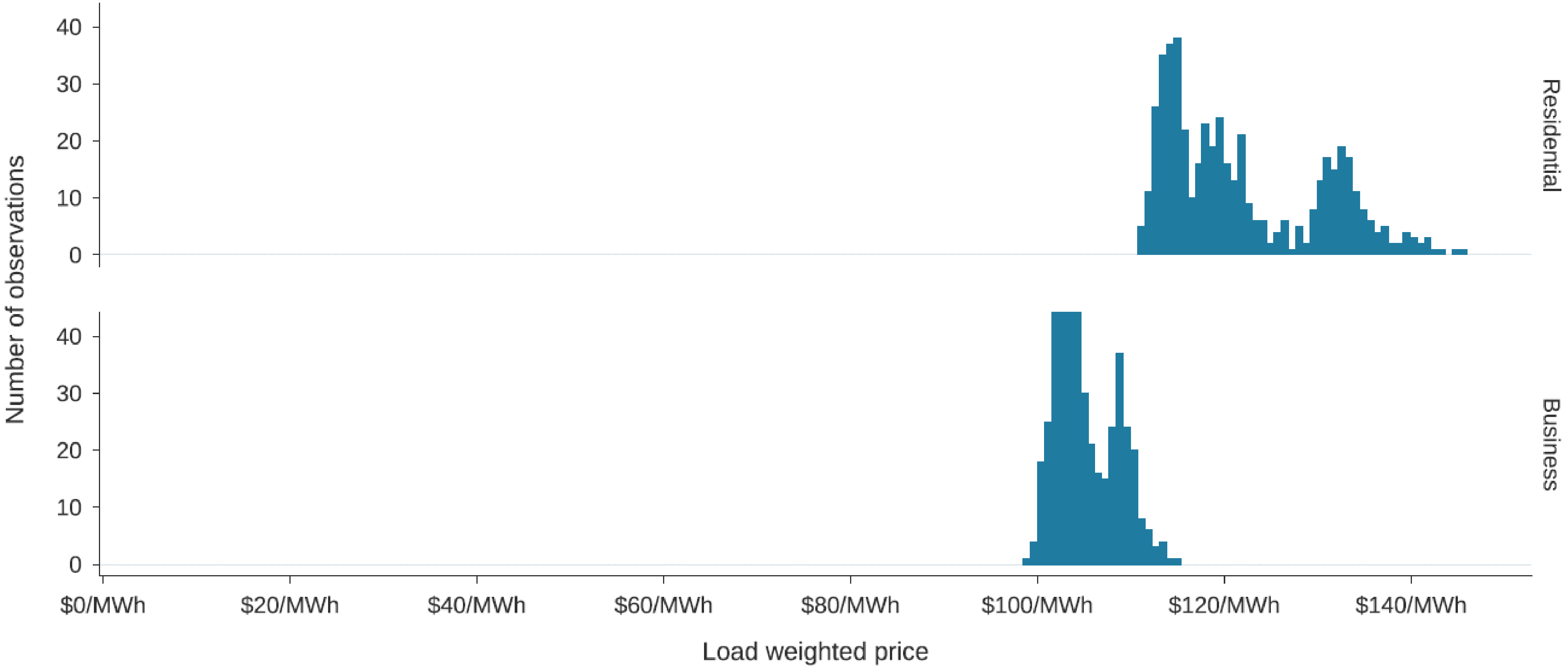
Source: Frontier Economics

Figure 12: Distribution of load-weighted price for simulated years for residential and business load – AusNet



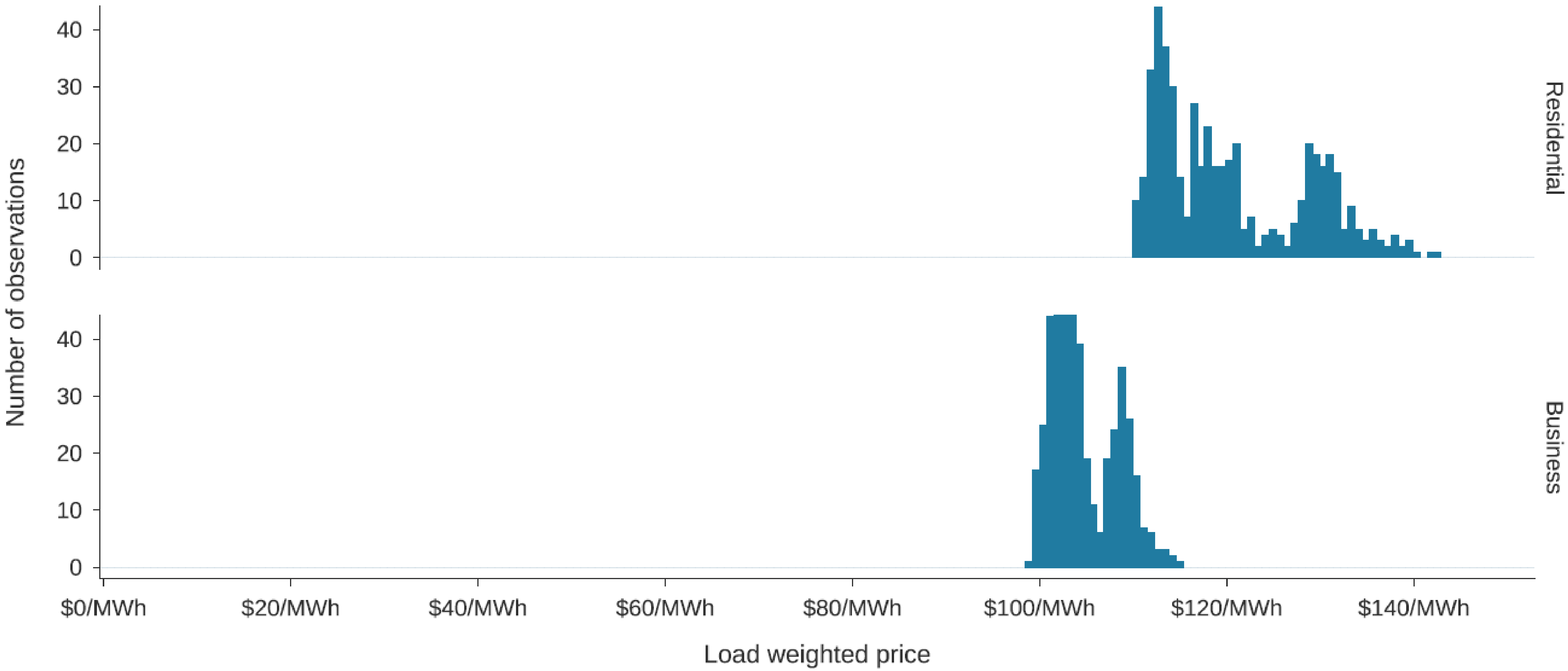
Source: Frontier Economics

Figure 13: Distribution of load-weighted price for simulated years for residential and business load – Jemena



Source: Frontier Economics

Figure 14: Distribution of load-weighted price for simulated years for residential and business load – United



Source: Frontier Economics

4 Contract prices

This section addresses the third question we need to answer to estimate the WEC:

- What is the cost of financial hedging contracts?

As discussed, our approach to assessing the WEC that retailers face is based on an estimate of the cost that a prudent retailer would face in supplying electricity to their customers, having regard to the hedging contracts that a prudent retailer is likely to enter into. The hedging contracts that we base this analysis on are ASXEnergy contracts. There are three main types of electricity contracts that are traded on ASXEnergy:

- Base swaps for each quarter.
- Peak swaps for each quarter.
- Base $300 caps for each quarter.

These contracts trade for several years in advance. Prices are published by ASXEnergy for each contract for each trading day.

Contract price data

Figure 15 through **Figure 17** set out the relevant trading data for each of these three contract types, for each quarterly product. The trading data that is presented is open interest (which measures the total volume of contracts in the market), the settlement price and the trading volume.

We can see from **Figure 15** through **Figure 17** that base swap contracts for 2023/24 are currently trading regularly. Indeed, we can see that trade in these contracts is occurring on most trading days. For base swap contracts for Q3 and Q4 2023, trade was very elevated on 21 November 2022, which is when options for those contracts are exercised. This regular trade in base swap contracts suggests that the daily prices for base swaps does provide a genuine indication of the market's view of future prices.

However, trade in caps, and particularly peak swaps, is lower. Given that peak trade very irregularly, there is the prospect that the available prices for peak swaps for 2023/24 may not represent the market's current view of likely price outcomes for 2023/24. We have observed this trend for declining trade in peak swaps over a number of years. But trade for 2023/24 is lower than previous years, with trade volumes at very low and infrequent levels.

While trade volumes for peak swaps are currently very low, and trade is very infrequent, we do note that changes in the quoted settlement prices (which occur because settlement prices can be affected by bid-ask spreads even in the absence of trade) for peak swaps are reasonably aligned with changes in base swap prices over this period.

However, because of the very low trade in these contracts, using a trade-weighted approach to estimating contract prices, as the ESC has adopted and stakeholders have supported in previous years, would mean that much of this information on market prices is not accounted for. For instance, in the 12 month averaging period for this draft report, there has been trade in Q3 and Q4 2023 peak swaps on only one day (13 December 2022) and no trade in Q1 and Q2 2024 peak swaps. Using a trade-weighted approach would mean that the only price that would be accounted for Q3 and Q4 2023 peak swaps would be the price on 13 December 2022. And since there has been no trade in Q1 and Q2 2024 peak swaps there is, strictly speaking, no trade-weighted price for those quarters.

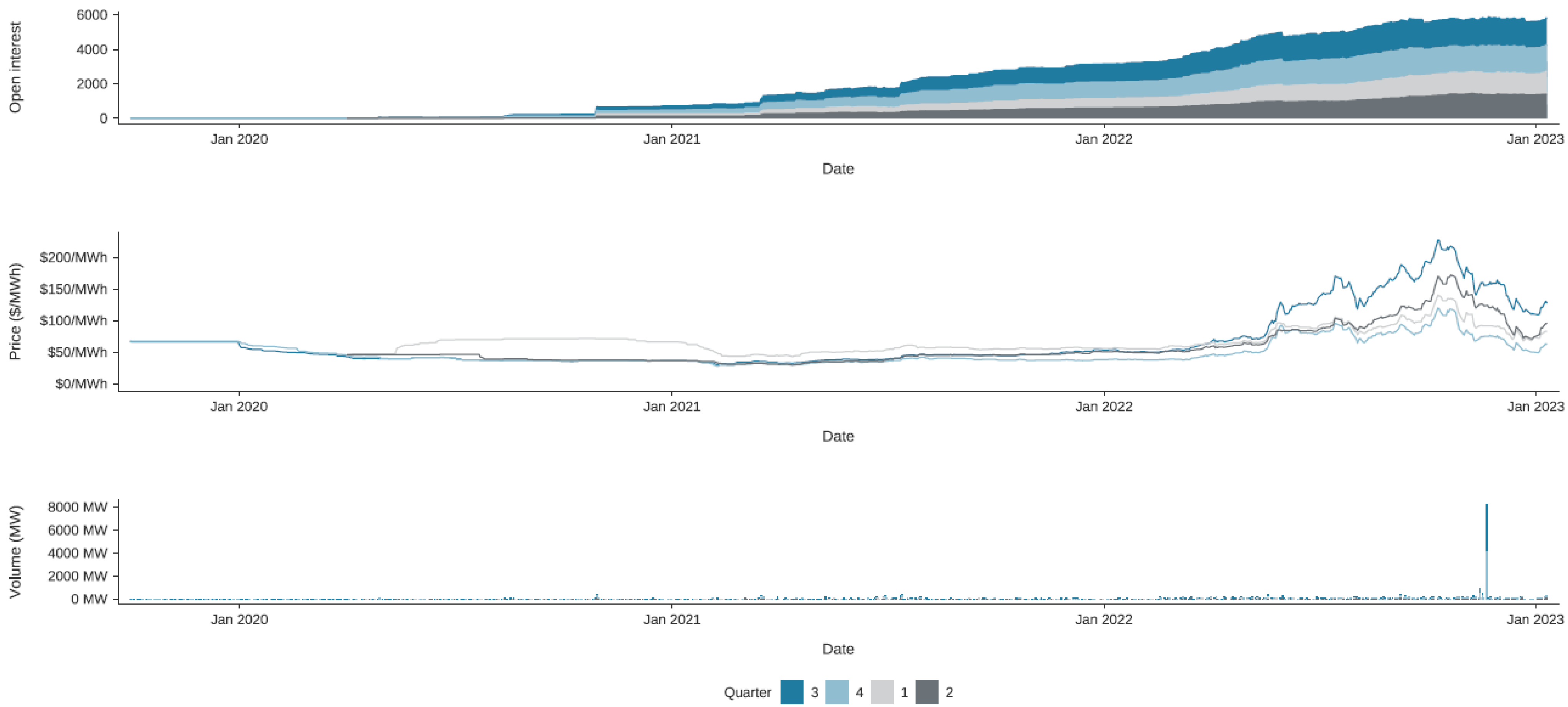
For these reasons, for this draft report we have used a time-weighted approach for calculating the peak swap prices for all peak swap contracts.

We note that this has the effect of increasing the calculated contract prices for Q3 and Q4 2023 peak swaps: for Q3 2023 peak swap contracts the time-weighted average price of $161.04 is slightly higher than the price of $154.30 on 13 December 2022 when the only trade occurred; for Q4 2023 peak swap contracts the time-weighted average price of $89.68 is materially higher than the price of $67.29 on 13 December 2022 when the only trade occurred.

For Q1 and Q2 2024 peak swaps, for which there has been no trade, and for which, therefore there is no trade-weighted price, our view is that the time-weighted price is the most logical alternative in any case.

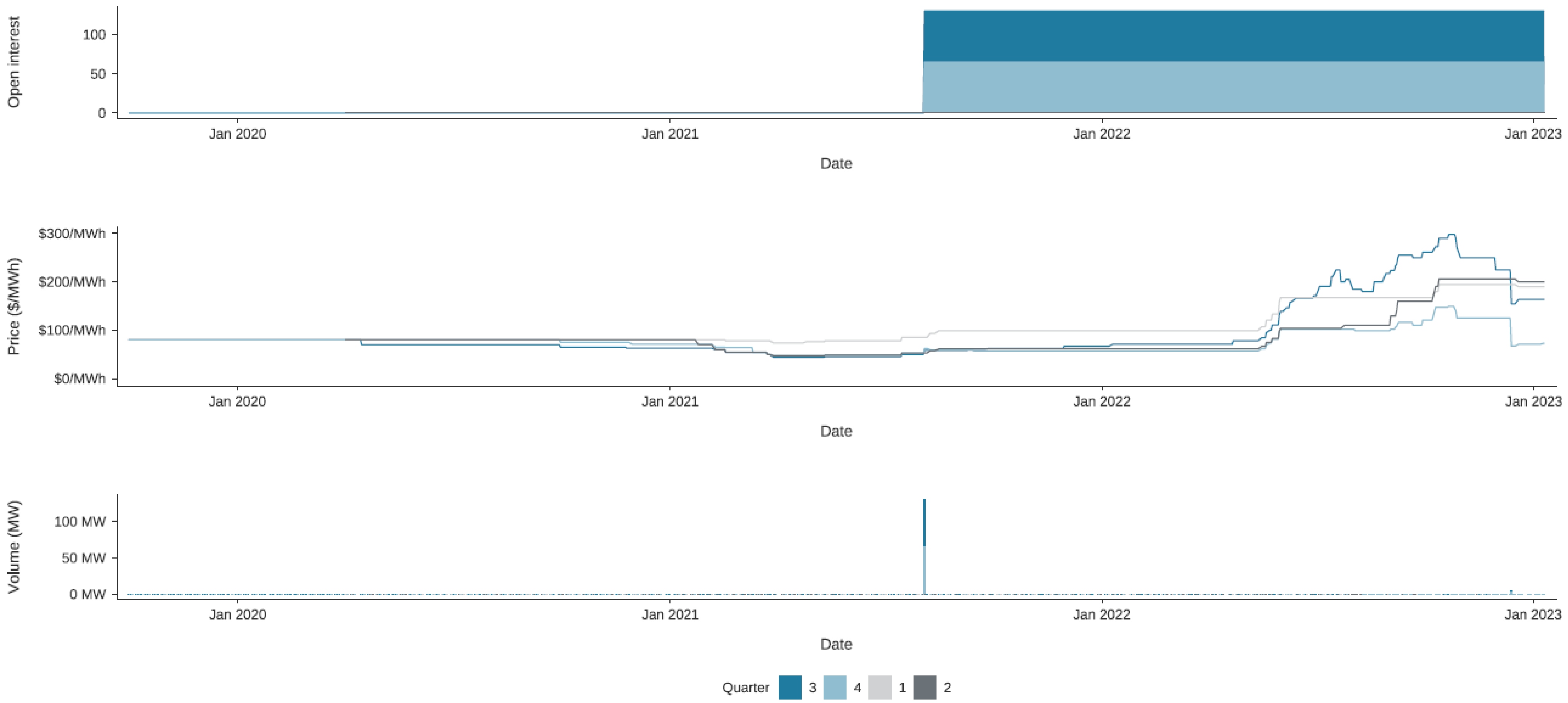
The overall impact on the WEC of this change from a trade-weighted approach to a time-weighted approach for peak swaps is small: around 1% difference to the WEC calculated for this draft report.

Figure 15: Victorian base swaps – open interest, prices and volumes for 2023/24



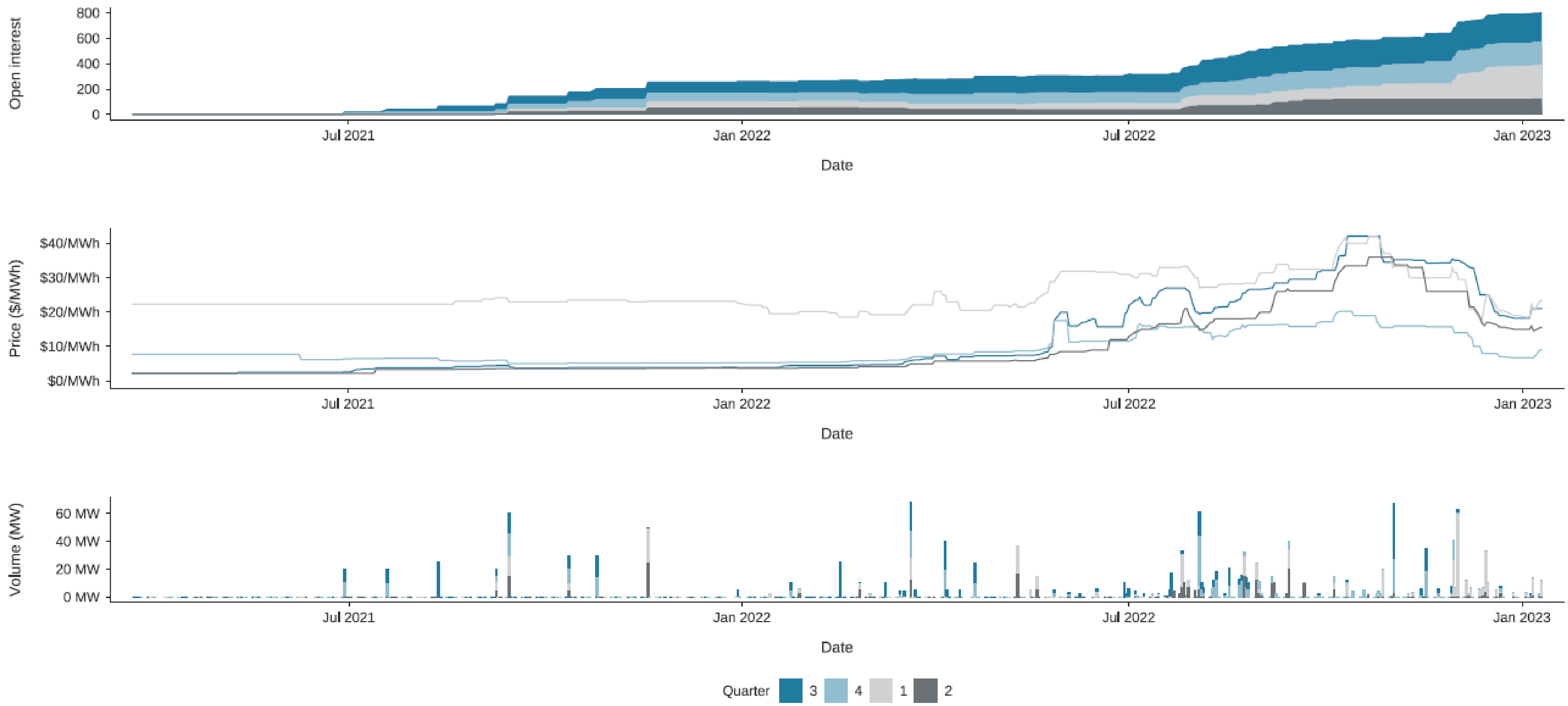
Source: Frontier Economics analysis of ASX data

Figure 16: Victorian peak swaps – open interest, prices and volumes for 2023/24



Source: Frontier Economics analysis of ASX data

Figure 17: Victorian base $300 caps – open interest, prices and volumes for 2023/24



Source: Frontier Economics analysis of ASX data

To determine the WEC we use this historical contract price data to determine the cost of ASXEnergy contracts. Our view is that economic decisions in competitive markets will be based on the market value of contracts (and we consider 40-day average prices a good proxy for this market value), regardless of when those contracts are purchased. If a retailer has purchased contracts in the past at prices above the current market price, we would expect that competition from existing or new entrant retailers would force the retailer to make retail price offers based on the current cost of purchasing contracts; to do otherwise would be to risk losing customers to competitors able to enter or expand by purchasing contracts at the current cost and making retail price offers based on those current costs. Similarly, if a retailer has purchased contracts in the past at prices below the current market price, we would expect that maximising shareholder value would require them to make retail price offers based on the current cost of purchasing contracts; making retail price offers based on lower historical contract costs would result in less profit than simply selling the contracts again at the current contract price.

However, there may be good reasons that a regulator will choose to base regulated prices on something other than 40-day average contract prices. For instance, a longer averaging period, such as 12 months or 24 months, would be expected to provide regulated prices that are more stable over time and would also likely result in regulated prices that are more reflective of incumbent retailers' actual historical costs (since most retailers will buy contracts over a period of time leading up to the settlement year). The ESC has asked us to use 12-month trade weighted contract prices in estimating the WEC. We calculate the 12-month trade weighted contract price for each contract by taking an average of the daily settlement price for that contract over the last 12 months, but weighting each daily settlement price by the share of the total volume of trade over the last 12 months that happened on that day. This means that the settlement price on a day on which no trade occurred is given a weighting of zero in calculating the 12-month trade weighted contract price, while the settlement price on the day on which the most trades occurred in the last 12 months is given the highest weighting.

As discussed, given trade in peak swaps has been very infrequent, we use a time-weighted approach for determining peak swap prices.

In response to the ESC's consultation paper, AGL pointed to the high volume of trade in swaps that occurs on the day that options are exercised. As discussed, this high volume of trade can be seen in **Figure 15**, occurring on 21 November 2022 for Q3 and Q4 2023 contracts. AGL noted that with the increase in popularity of options contracts the volume of trade on the day that options are exercised is increasing. Under a trade-weighted approach to determining the contract price, this means that the closing price on this day has a much higher effect on the resulting contract price than the closing price on any other day. AGL suggested that one way to deal with this would be to exclude the data from that day from the calculation of the trade-weighted contract price. Since we do not assume that retailers enter into options as part of the assumed hedging position, this seems like a sensible suggestion. We have removed the data from that day from the calculation of the trade-weighted contract price for Q3 and Q4 2023 contracts for this draft report.

Adopting the approach described above results in the ASXEnergy contract prices that are shown in **Table 1**, for contract prices up to 10 January 2023.

Table 1: 12-month trade weighted average ASXEnergy derivative prices for Victoria (2023/24 dollars)

	Product	Status	Year	Quarter			
				Q3	Q4	Q1	Q2
TRADE WEIGHTED	$300 Caps	Base	2023/24	$19.60	$13.53	$27.69	$18.02
	Swaps	Base	2023/24	$129.44	$69.48	$86.49	$99.40
	Swaps	Peak *	2023/24	$161.04	$89.68	$148.53	$119.51

*Source: Frontier Economics analysis of ASXEnergy data. * Peak swaps are time-weighted.*

In response to the ESC's consultation paper, a number of stakeholders have suggested that some retailers, particularly smaller retailers, are increasingly having to rely on OTC contracts because of lack of access to trade of ASX contracts. These stakeholders also noted that OTC contracts have been trading at higher prices than ASX contracts in recent times. These stakeholders point to the findings of the ACCC's November report on the National Electricity Market, which, based on data received under the ACCC's compulsory information gathering powers, found evidence that from Q2 2022 onwards, a number of smaller retailers had lost access to ASXEnergy contracts and that prices for OTC contracts were notably higher than for ASXEnergy contracts.[4]

In principal, there is no reason that our approach to estimating WEC could not account for both ASXEnergy contracts and OTC contracts. The key reason that we do not include OTC contracts in our approach to estimating WEC is because data on the prices of OTC contracts is not publicly reported.

To date, relying only on prices for ASXEnergy has not, in our view, been a significant issue. The long-term trend in the National Electricity Market is that ASXEnergy contracts have tended to be relied on to a greater extent over time, and OTC contracts have tended to be relied on to a lesser extent over time. Also, when we have observed ASXEnergy contract prices and OTC prices, these prices have tended to be very similar. This can be observed in the ACCC's report, which shows that prices for ASXEnergy contracts and OTC contracts in Victoria were quite similar throughout 2021 and Q1 2022, diverged markedly in Q2 2022, with OCT contract prices notably higher than ASXEnergy contract prices, before again becoming quite similar by Q3 2022.

Given this, and the lack of publicly available data on OTC contract prices, for this draft report we continue to rely only on the prices of ASXEnergy contracts.

4 ACCC, *Inquiry into the National Electricity Market*, November 2022 Report, page 2.

5 Contract position

This section addresses the final question we need to answer to estimate WEC:

- What kind of hedging position is a prudent retailer likely to adopt?

We use our portfolio optimisation model – *STRIKE* – to determine the efficient mix of hedging products that a prudent retailer would likely adopt. *STRIKE* calculates an efficient frontier, which represents the contracting positions that provide the lowest energy purchase cost for a given level of risk (as measured by standard deviation).

STRIKE applies a Minimum Variance Portfolio (MVP) approach to the task of hedging a retailer's exposure to wholesale spot prices. *STRIKE* incorporates an estimate of a retailer's exposure to the wholesale spot market, which is determined by the retailer's load and wholesale spot prices. There is an expected return and a variance associated with this. *STRIKE* also incorporates the types of hedging products that are typical in the electricity industry. These contracts – swaps and caps – generate cashflows that also have an expected return and a variance. Instead of assessing the expected return and associated risk for each asset in isolation, *STRIKE* applies the concepts of portfolio theory to evaluate the contribution of each asset to the risk of the portfolio as a whole. Based on this approach, *STRIKE* calculates efficient hedging strategies.

In order to determine a hedging position for the purposes of estimating the WEC for each customer type in each distribution area in Victoria, we make use of the following inputs in *STRIKE*:

- Forecast spot prices and load, as discussed in Section 3. As we discussed, we have developed 500 simulated years of half-hourly spot prices and load for 2023/24. There is a distribution of outcomes within these 500 simulated years. Our view is that an efficient retailer's hedging position should have regard to the uncertainty associated with what kind of year 2023/24 will be. For example, will 2023/24 be a year with high prices and high load corresponding, so that the load-weighted price is high, or will 2023/24 be a year with low prices and high load corresponding, so that the load-weighted price is low? To account for this uncertainty, we input 7 simulated years into *STRIKE*, representing those simulated years that represent the 99th, 95th, 75th, 50th, 25th, 5th and 1st percentile when the 500 simulated years are ranked according to load-weighted price.
- Contract prices, as discussed in Section 4. We present results for 12-month trade weighted contract prices.

As discussed, *STRIKE* calculates an efficient frontier, which represents the contracting positions that provide the lowest energy purchase cost for a given level of risk. The contract position that we use to calculate the WEC is based on the most conservative contracting position on the efficient frontier, which is the point on the efficient frontier with the lowest risk (but highest cost).

Outlined in **Figure 18** to **Figure 27** are the resulting contract positions at the conservative point for 2023/24, for each load profile and for each distribution area. For each quarter (the vertical panels) and each peak/off-peak period (the horizontal panels), the charts show the following:

- The distribution of half-hourly load for the 48 half-hours of the day (shown by the box plots, including the dots representing outliers, in the 'Load' panel).

- The distribution of half-hourly spot prices for the 48 half-hours of the day (shown by the box plots, including the dots representing outliers, in the 'Spot price' panel). The price chart is truncated at a spot price of $800/MWh to aid visibility of price outcomes.
- The quantity of swaps and caps at the conservative point of the efficient frontier (shown by the coloured areas in the 'Load' panel).

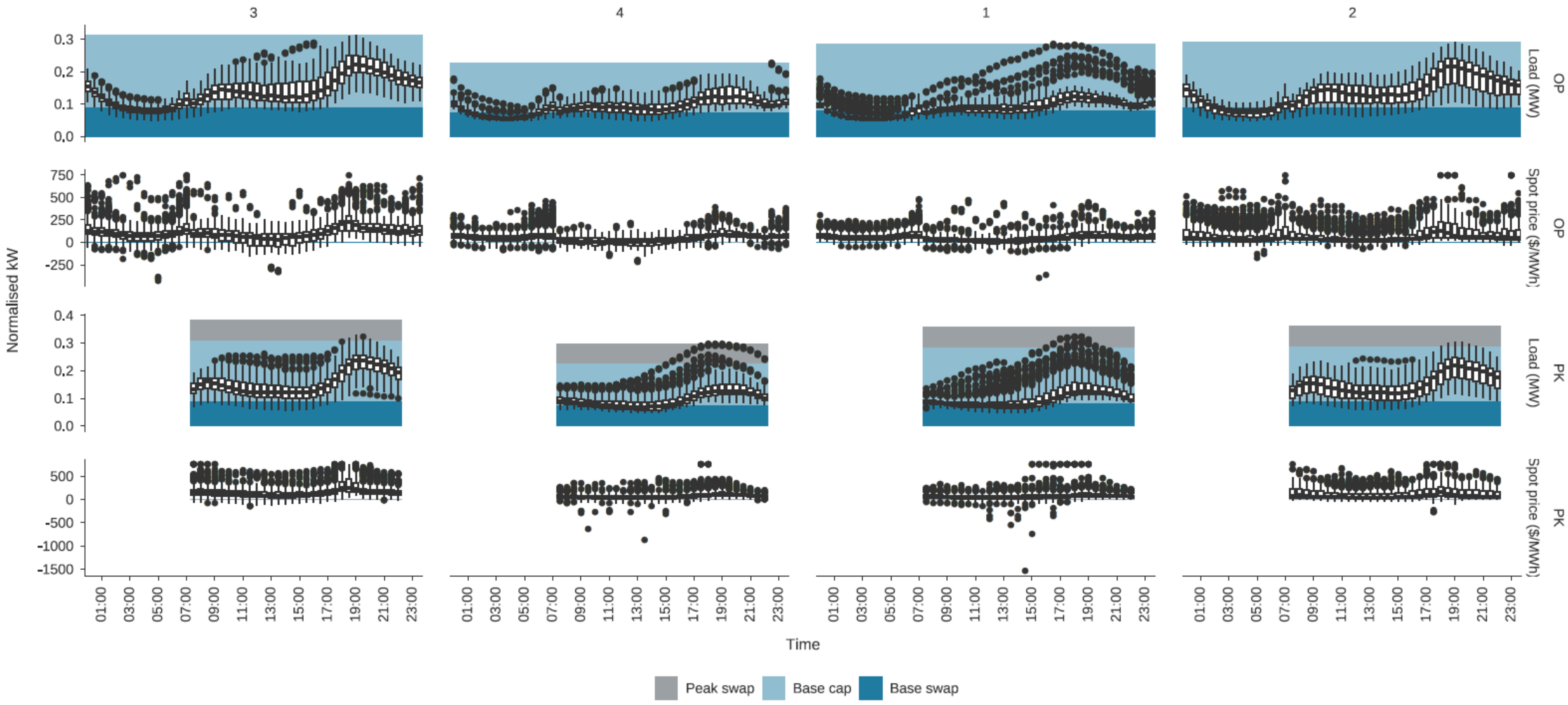
In general, the contract position at the conservative point involves:

- purchasing swaps to cover (approximately) average demand (or slightly lower in off-peak periods)
- purchasing caps, on top of that, to cover (approximately) to peak demand
- in some cases, incurring a small amount of pool exposure at absolute peak demand times.

As seen in **Figure 18** to **Figure 27**, the contract position at the conservative point generally results in complete coverage of the highest demand half hours, but may not always do so. The reason that there can remain some residual pool exposure even at the conservative point is that *STRIKE* balances the costs and risks of remaining exposed to the spot price at these highest demand half hours against the costs and risks associated with being over-contracted. Signing additional contracts is neither costless nor riskless, and while being exposed to the spot price during a small number of high demand half-hours can result in large payments, being over-contracted for a large number of lower demand half-hours can also result in large payments. Some retailers may have a preference for additional contract cover to meet forecast peak demand in all cases, but we note that the volatility allowance (discussed in Section 0) is intended to reflect the residual risk at the conservative point and could be used to purchase additional cap cover.

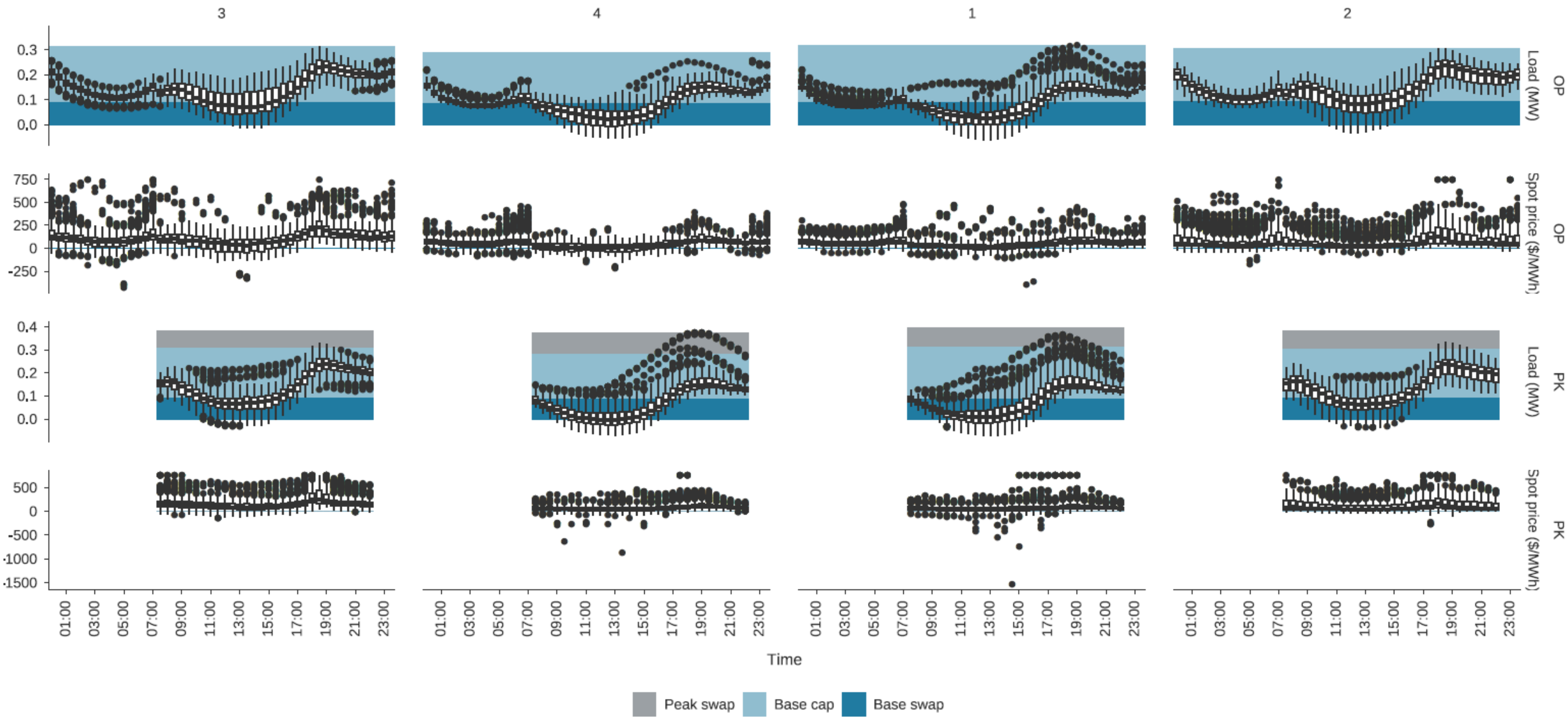
It should also be noted that the conservative point on the efficient frontier reflects the contract position that achieves the lowest risk given the projected state of the world that is input into *STRIKE*. In the event that different states of the world were input into *STRIKE*, the model would find a different contract position that achieves the lowest risk. In particular, if it were assumed, for instance, that next year will have an unusually large number of very high price events that coincided with high load, then the model would certainly find a different contract position that achieves the lowest risk. Load forecasts and price forecasts (and their correlation) are important to the costs that retailers face in supplying regulated customers. We use the best available information to develop load forecasts and price forecasts that are consistent with the observed peakiness of historic load and historic prices (and the observed correlation between) so that the *STRIKE* contract position is based on a good estimate of future conditions.

Figure 18: Contract position for CitiPower residential load, ASXEnergy contract prices



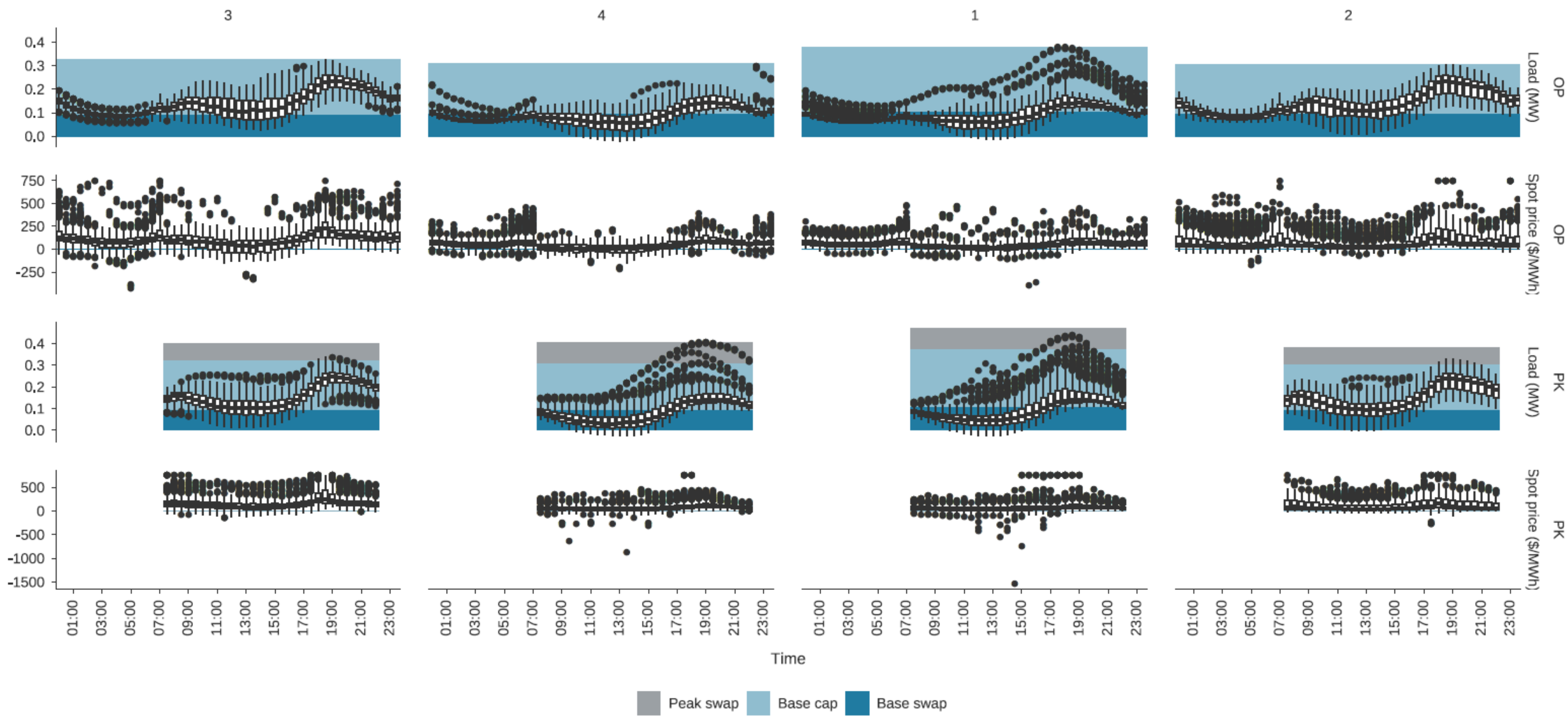
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 19: Contract position for Powercor residential load, ASXEnergy contract prices



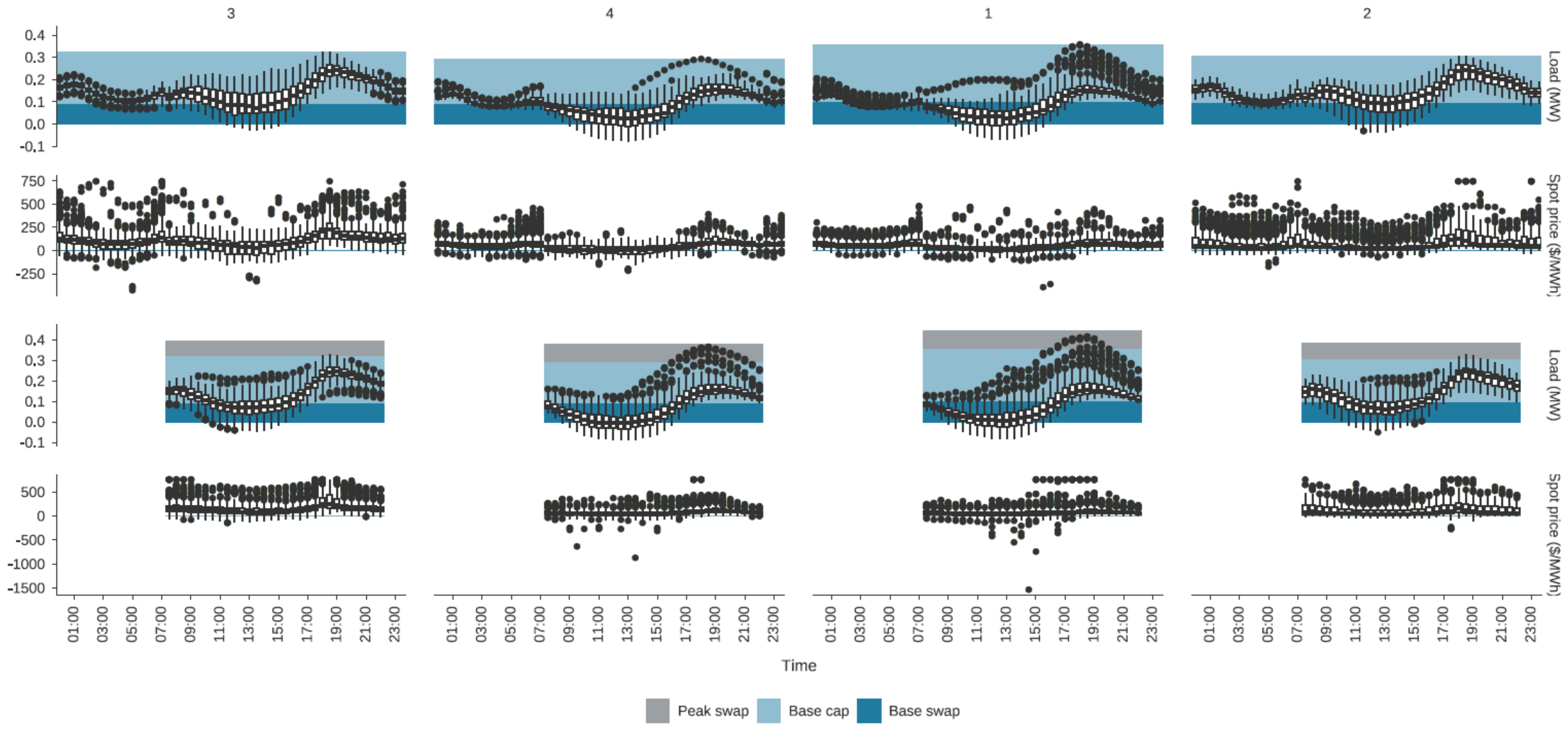
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 20: Contract position for Jemena residential load, ASXEnergy contract prices



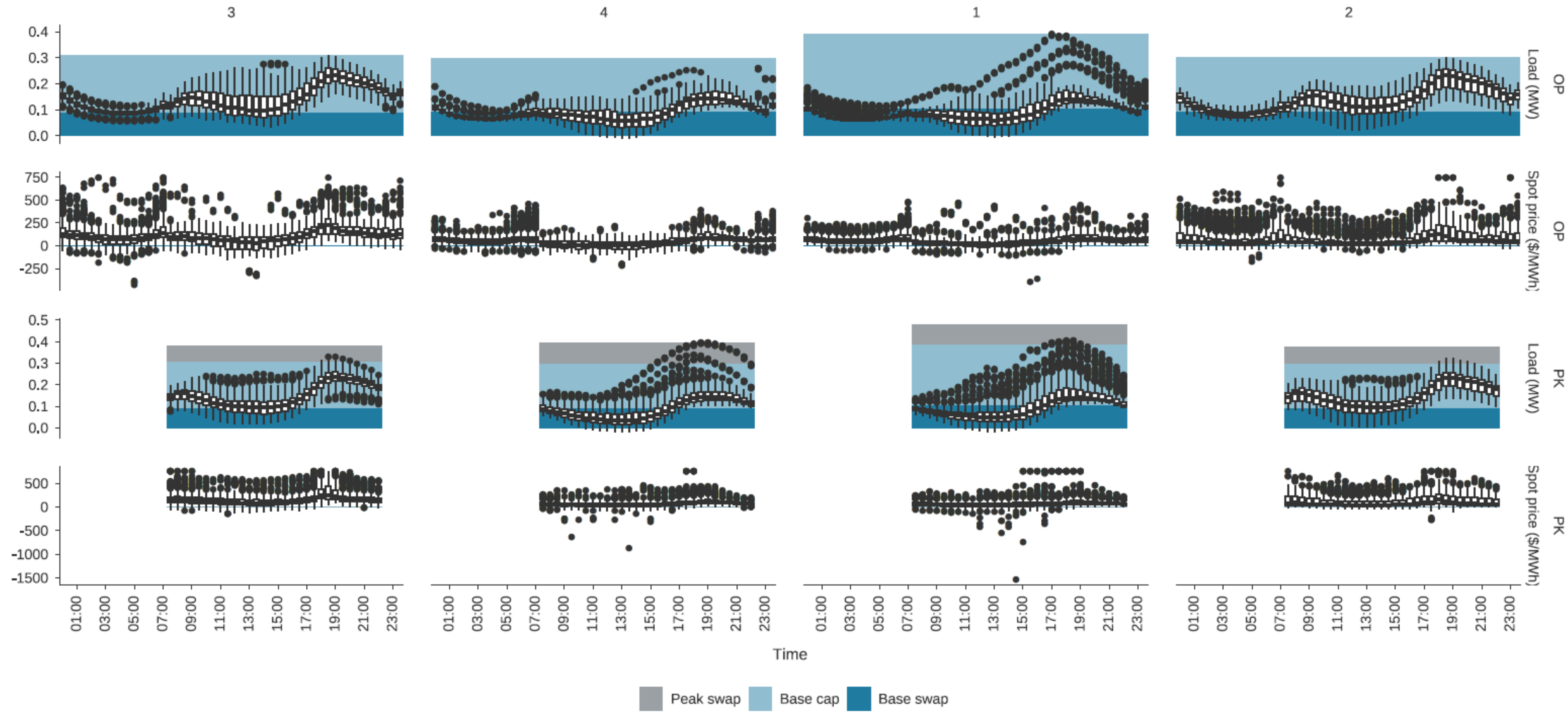
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 21: Contract position for AusNet residential load, ASXEnergy contract prices



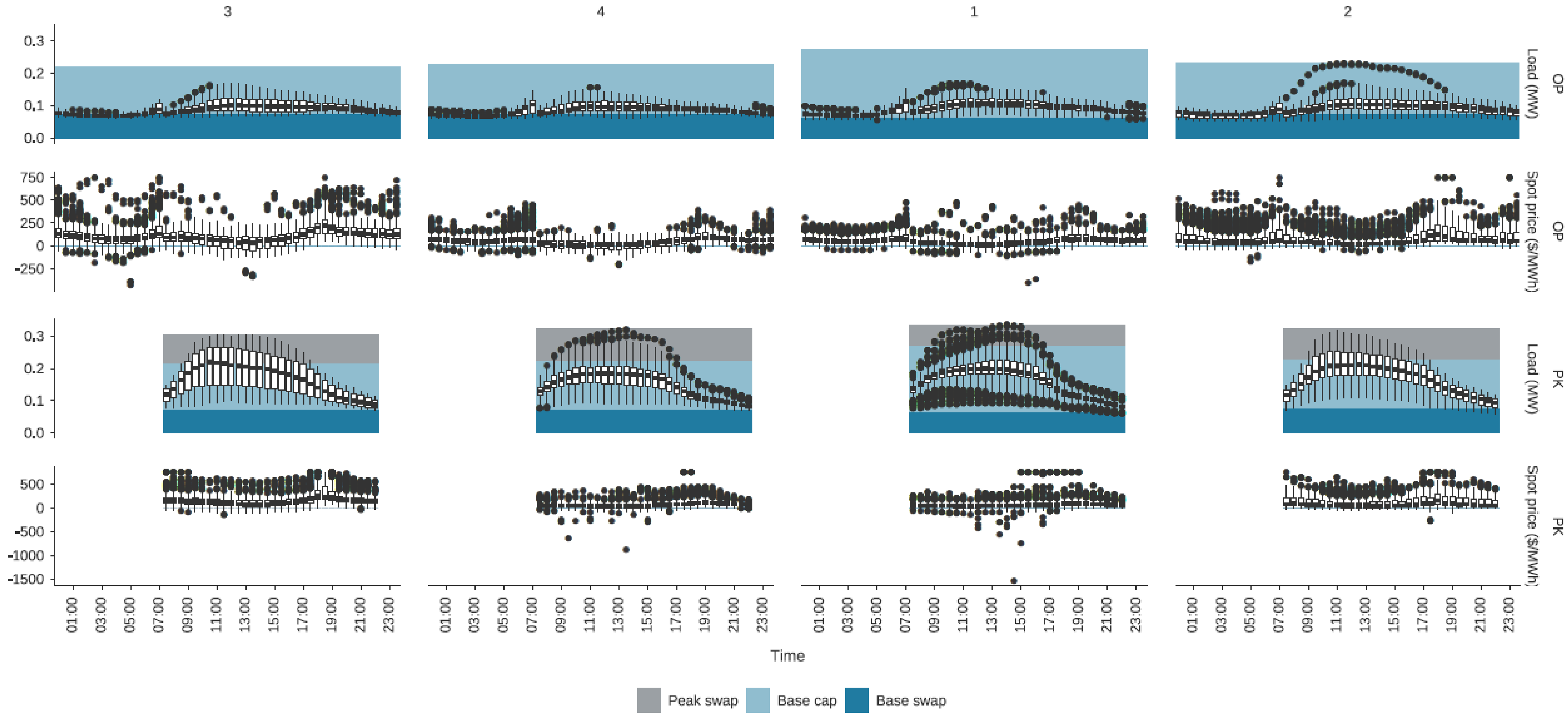
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 22: Contract position for United residential load, ASXEnergy contract prices



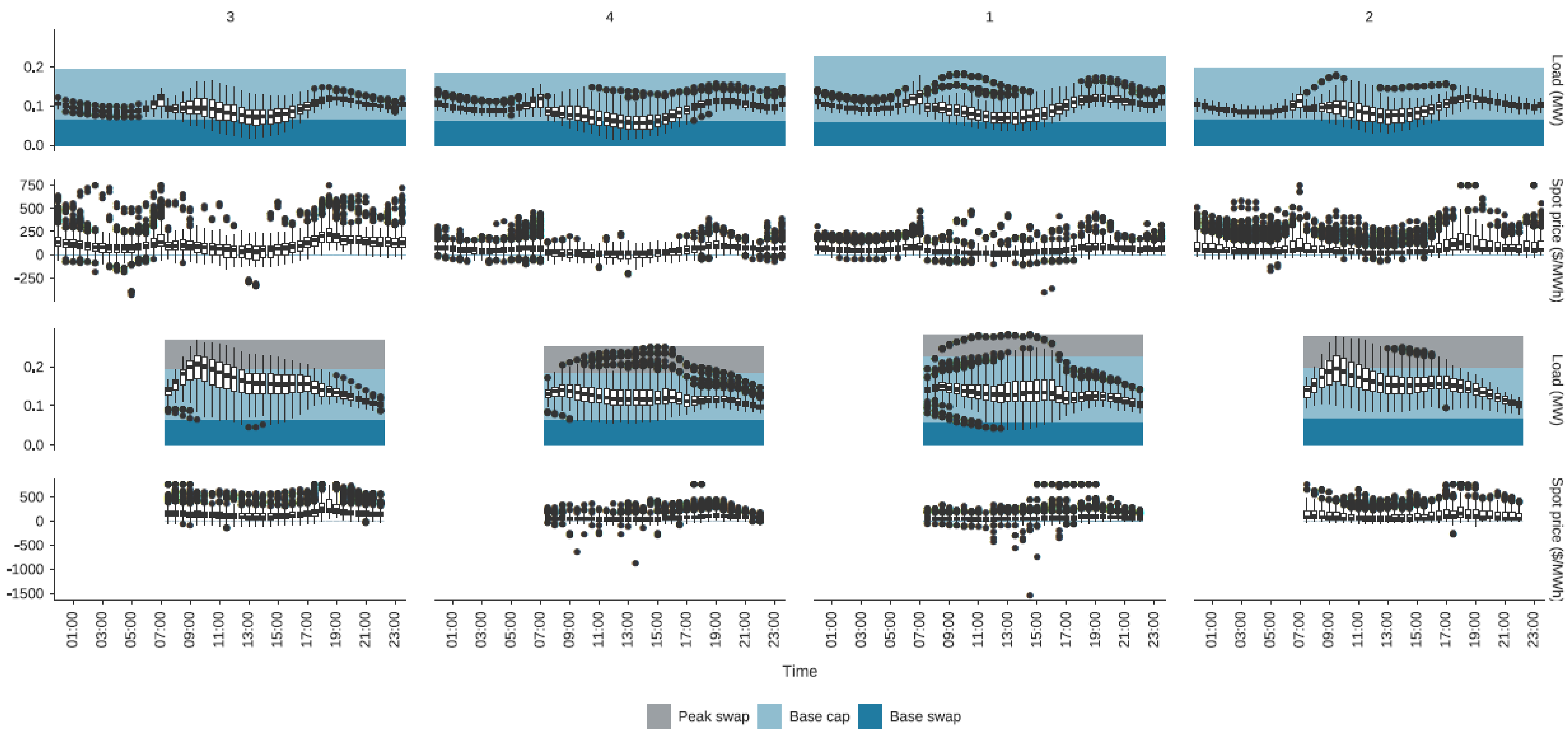
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 23: Contract position for CitiPower business load, ASXEnergy contract prices



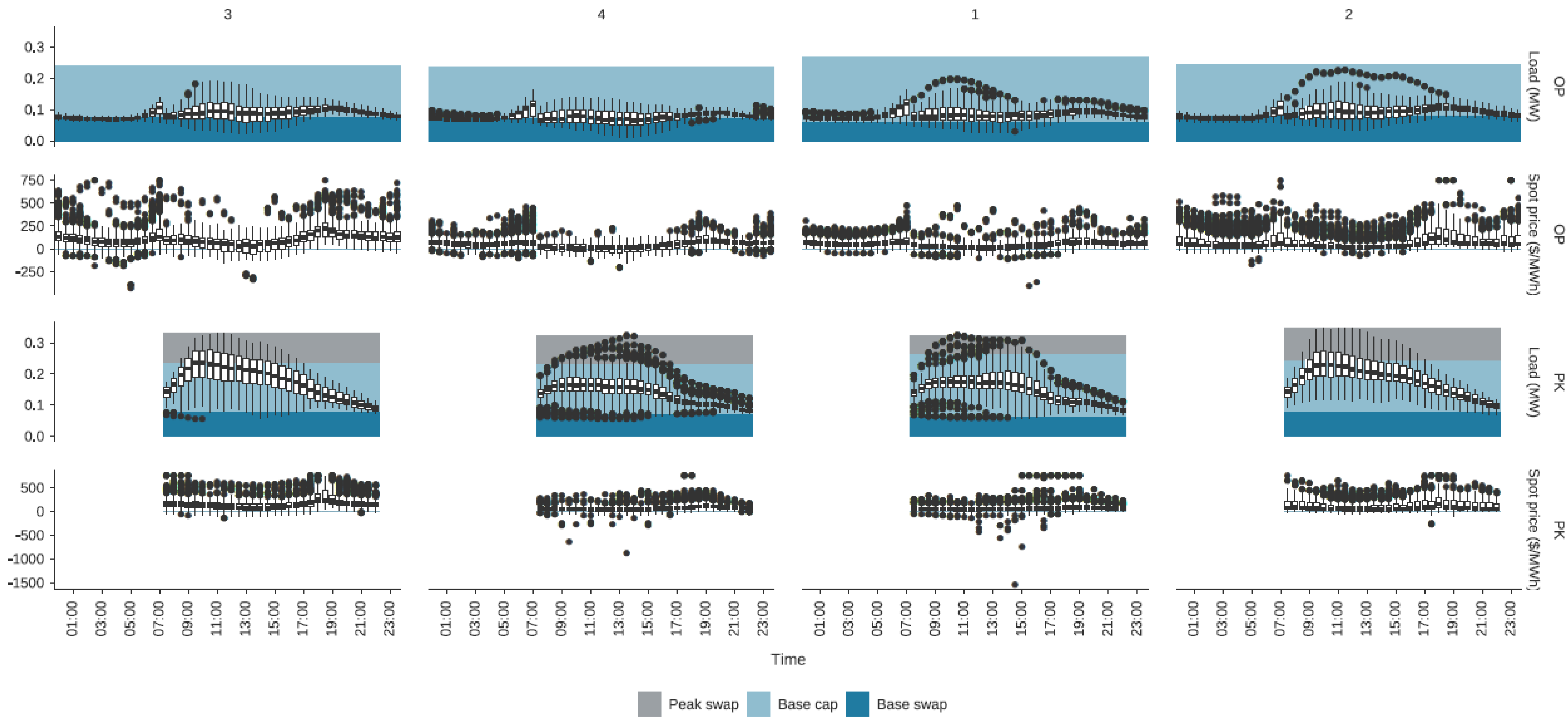
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 24: Contract position for Powercor business load, ASXEnergy contract prices



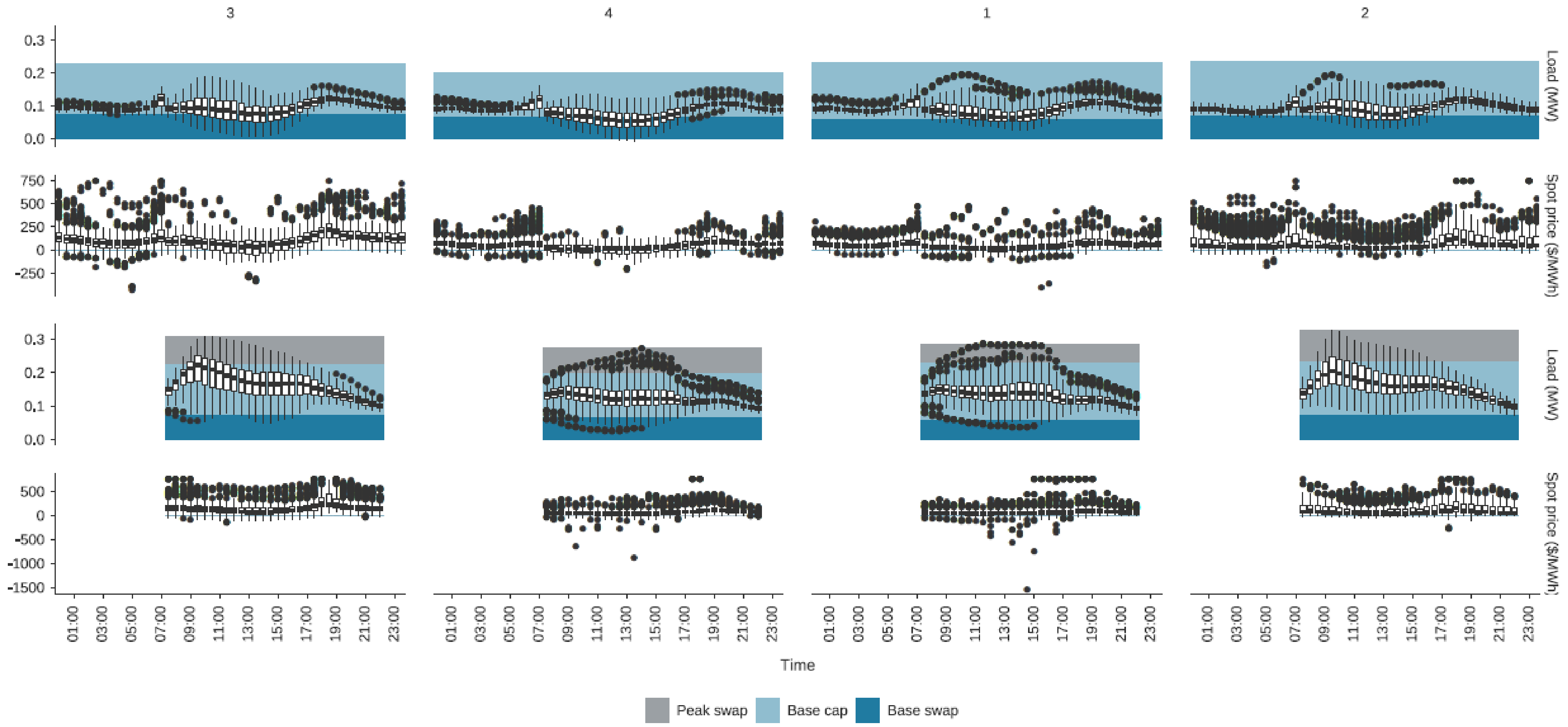
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 25: Contract position for Jemena business load, ASXEnergy contract prices



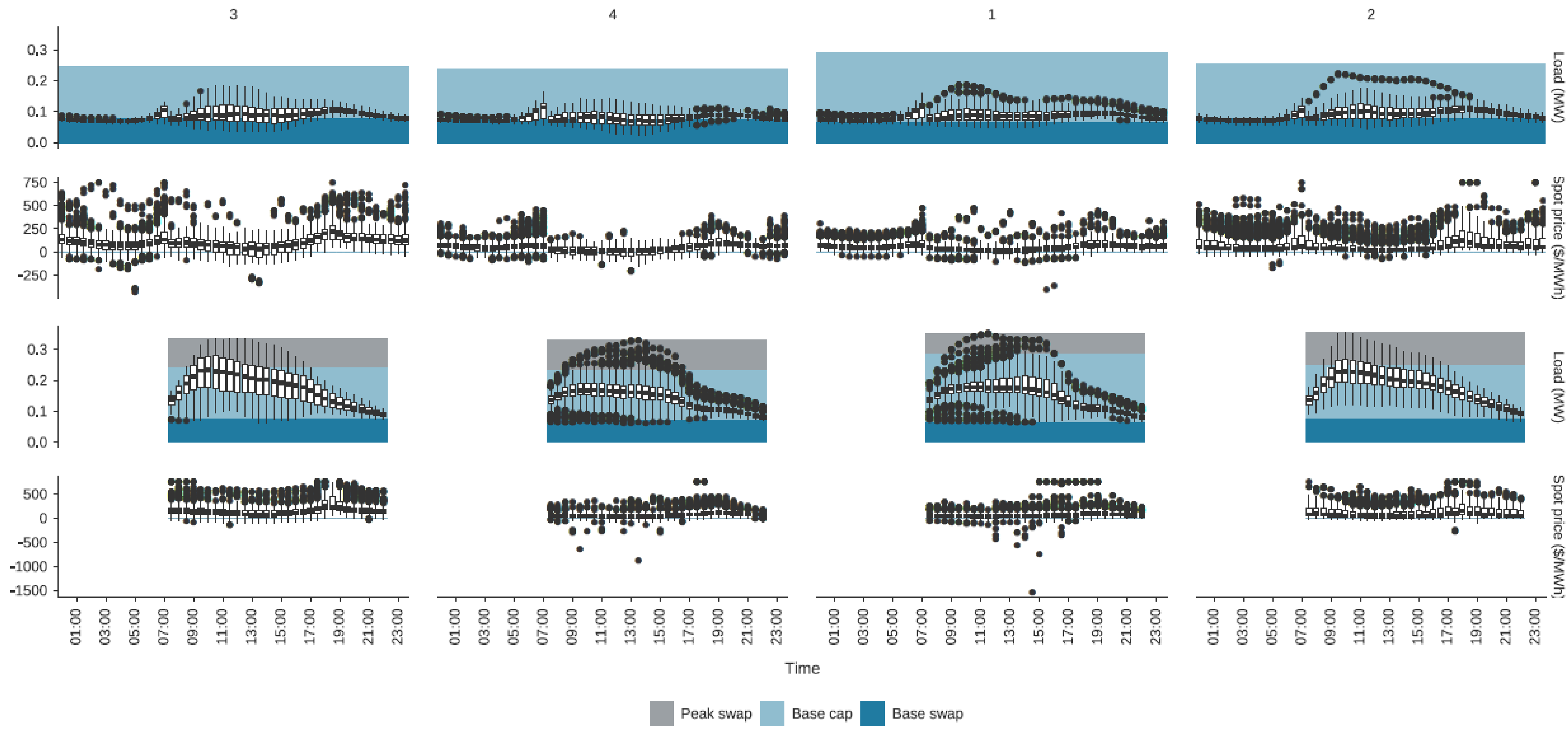
Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 26: Contract position for AusNet business load, ASXEnergy contract prices



Note: Spot price chart truncated at a spot price of $800/MWh.

Figure 27: Contract position for United business load, ASXEnergy contract prices



Note: Spot price chart truncated at a spot price of $800/MWh.

6 Wholesale electricity costs

Based on the data and modelling discussed in Section 3 through Section 5, this section reports the WEC that we have estimated.

6.1 Wholesale electricity costs

We estimate the WEC by calculating settlement payments and differences payments resulting from the half-hourly spot prices and load, contract prices and contract position that we have developed.

Results

The WECs that we have estimated are based on half-hourly spot prices and load from the median simulated year (when these years are ranked according to WEC). The WECs that we have estimated are based on 12-month trade weighted average ASXEnergy contract prices up to 10 January 2023. The WECs that we have estimated are based on the contract position from the conservative point on the efficient frontier for each DNSP.

These WECs are set out in **Table 2**.

Table 2: Modelled market-based wholesale electricity cost result

Entity	Wholesale electricity costs ($/MWh, real $2023/24)	
	Residential	Business
AusNet	$160.58	$130.16
CitiPower	$146.40	$128.35
Jemena	$160.86	$131.53
Powercor	$158.29	$126.71
United	$158.96	$131.87

In response to the ESC's consultation paper, a number of stakeholders raised questions about the extent to which the approach to estimating WEC properly accounted for risk. They questioned the extent to which the approach to estimating WEC accounted for the market volatility and prices that occurred during 2022, or questioned whether basing the WEC on the 50^{th} percentile of estimated outcomes provided sufficient risk management.

In our view, the approach to estimating WEC does account for changes in market conditions. For instance, our estimate of WEC for 2023/24 now includes the volatile prices that occurred in

Q2 2022 in the Monte Carlo analysis that we undertake, so that these volatile prices now form part of the estimated price and load profiles on which we base the WEC. Similarly, our estimate of WEC for 2023/24 does of course account for the fact that both wholesale contract prices for 2023/24 and expectations of future spot prices for 2023/24 are now higher than they were at the equivalent time when estimating the WEC for 2022/23.

Our approach for estimating the WEC has been designed to base estimates of future spot price volatility and future load volatility entirely on recent historical volatility. This is done to ensure that the approach is as transparent as possible and that the approach can be replicated by interested stakeholders. In any case, even if we had used a forecasting model to predict future price outcomes, we would not have forecast the level of price volatility that occurred in Q2 2022 as a likely outcome.

However, this does not mean that our approach to estimating the WEC leaves retailers exposed to unexpected price volatility. Nor does it mean that setting the WEC based on the 50th percentile of estimating outcomes leaves retailers exposed to losses 50 per cent of the time. The approach that we use is to set the WEC based on a hedging position that provides retailers with as little risk as possible. As we have seen, this implies having a total contract position that more or less matches peak demand. If retailers adopt a contract position like this, they will be substantially protected from higher than expected prices and prices that are more volatile than expected. Similarly, our approach to estimating the WEC is based on the assumption that a retailer will individually hedge each of residential and small business customers in each of the 5 distribution networks in Victoria. In practice, retailers will have a mix of customer types in different parts of Victoria (and, indeed, the NEM) and will benefit from portfolio benefits from supplying this mix of customers. These portfolio benefits will lower their total costs of hedging. For these reasons, we consider that efficient retailers should generally be able to achieve wholesale costs that are lower than our estimates of the WEC, and the evidence that retailers have generally been able to offer market prices that are lower than the VDO suggests that this has been the case.

Finally, as discussed below, our approach provides for a volatility allowance to manage residual risk.

6.2 Volatility allowance

As discussed, the WECs that we have estimated are based on half-hourly spot prices and load from the median simulated year. The volatility allowance is intended to compensate retailers for the residual risk to which they are exposed, even when contracted at the conservative point. The volatility allowance is calculated based on the cost of holding working capital to fund cashflow shortfalls that could arise in years when the actual WEC is higher than we have estimated for the median simulated year. The working capital requirement is based on the difference between the WEC that we have estimated for the median simulated year and the WEC for the most costly simulated year for each distribution area. We then estimate the cost of holding sufficient working capital by applying a WACC of 7.5 per cent.

The volatility allowances calculated using this framework are set out in **Table 3**.

Table 3: Modelled volatility allowance

Entity	Volatility Allowance ($/MWh real $2023/24)	
	Residential	Business
AusNet	$0.43	$0.46
CitiPower	$0.36	$0.49
Jemena	$0.42	$0.54
Powercor	$0.39	$0.45
United	$0.38	$0.58

Source: Frontier Economics

7 LRET and SRES

In addition to estimating the WEC, our scope of work also includes estimating the costs that a retailer will face as a result of the following schemes:

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

This section reports our estimate of these costs.

7.1 LRET

The LRET places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP), which is set each year by the Clean Energy Regulator. LGCs are created by eligible generation from renewable energy power stations.

In order to calculate the cost to a retailer of complying with the LRET, it is necessary to determine the RPP for the retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC.

Renewable Power Percentage

The RPP establishes the rate of liability under the LRET and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year.

The RPP is set to achieve the renewable energy targets specified in the legislation. The Clean Energy Regulator is responsible for setting the RPP for each year.

The *Renewable Energy (Electricity) Act 2000* states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh's of renewable energy for the current year divided by the required GWh's of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not decrease the RPP to account for any growth in demand. As a result, this calculation is likely to overestimate the RPP for a given year when energy demand is growing.

The Clean Energy Regulator has published a RPP for 2023 of 18.96%. Using this 2023 RPP, and applying the default calculation, results in the same RPP for 2024 of 18.96%, and an estimated RPP for 2023/24 that is also 18.96%.

Cost of obtaining LGCs

We have used a market price for LGCs to determine the cost of complying with the LRET. The market price for LGCs is determined by taking a 12 month trade weighted average of LGC prices for trades settled in 2023/24, reported by Demand Manager.[5] This 12 month trade weighted average LGC price to 10 January 2023 is $54.66 per certificate ($2023/24).

Cost of complying with the LRET

Based on the RPP and the LGC price discussed above, the cost of complying with the LRET is $10.36/MWh ($2023/24).

7.2 SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by the Clean Energy Regulator. STCs are created by eligible small-scale installations based on the amount of renewable electricity produced or non-renewable energy displaced by the installation.

Liable entities can purchase STCs on the open market or through the STC Clearing House. There is a guaranteed price of $40/STC through the Clearing House, but certificates may take some time to clear, delaying payment to sellers of STCs.

In order to calculate the cost to a retailer of complying with the SRES, it is necessary to determine the STP for the retailers (which determines the number of STCs that must be purchased) and the cost of obtaining each STC.

Small-scale Technology Percentage

The STP establishes the rate of liability under the SRES and is used to determine the number of STCs that liable entities are required to surrender each year. The STP is determined by the Clean Energy Regulator.

The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year[6]
- the estimated amount of electricity that will be acquired for the year
- the estimated number of all partial exemptions expected to be claimed for the year

The STP is to be published for each compliance year by March 31 of that year. The Clean Energy Regulator is also required to publish a non-binding estimate of the STP for the two subsequent compliance years by March 31. The binding and non-binding STPs for 2023 and 2024 are set out in **Table 4**.

5 Available at: http://www.demandmanager.com.au/. Accessed 11th January 2023.

6 This is determined by the Clean Energy Regulator. In recent years it has estimated it based on the simple average of STC forecasts made by consultants to the Clean Energy Regulator.

Table 4: STPs published by the Clean Energy Regulator

Binding/Non-binding	Estimate/Forecast year	STP
Binding	2023	16.29%
Non-binding	2024	17.99%

Source: Clean Energy Regulator

Cost of obtaining STCs

For the purposes of this report, we assume that the cost of STCs is equal to this STC Clearing House price of $40/STC ($2023/24).

Historically, the reported spot price of STCs has typically been at, or close to, this price of $40/STC.

Cost of complying with the SRES

Based on the STC price discussed above, and the average of the binding 2023 STP and non-binding 2024 STP, the cost of complying with the SRES in 2022/23 is $6.86/MWh ($2023/24).

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