ACIL ALLEN

13 March 2024

Report to Australian Energy Regulator

Default Market Offer 2024-25

Wholesale energy and environment cost estimates for DMO 6 Draft Determination

About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

Suggested citation for this report

Default Market Offer 2024-25: Wholesale energy and environmental cost estimates for DMO 6 Draft Determination, ACIL Allen, March 2024

Contents

Figures

Contents

Tables

Contents

Introduction 1

ACIL Allen has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating specific cost inputs required for the determination of Default Market Offer (DMO) prices. Specifically, ACIL Allen is required to provide consultancy services to the AER to estimate the underlying wholesale and environmental cost inputs to inform the determination for 2024-25 (DMO 6).

These estimates are to be based on the relevant cost drivers for a retailer supplying electricity to residential and small business customers in non-price regulated jurisdictions (excluding Victoria).

This report provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination for DMO 6, using the methodology in our 2023-24 (DMO 5) Final Determination report to the AER, as well as considering stakeholder feedback in response to the AER's Issues Paper.

The report is presented as follows:

— Chapter 2 summarises our methodology.

— Chapter 3 provides responses to submissions made by various stakeholders following the release of the AER's *Default market offer prices 2024-25: Issues paper* (October 2023), where those submissions refer to the methodology used to estimate the cost of energy in regulated retail electricity prices.

— Chapter 4 summarises our derivation of the energy cost estimates.

Overview of approach 2

2.1 Introduction

In determining the DMO, the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (the Regulations) requires the AER to determine the annual consumption and annual retail bill amounts based on the following principles and policy objectives:

— an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region

— to reduce the unjustifiably high level of standing offer prices for consumers who are not engaged in the market

— to set DMO prices at a level that provides consumers and retailers with incentives to participate in the market

— to allow retailers to recover their efficient costs in servicing customers.

The overall objective of estimating the DMO is to ensure that the projected change in costs from one determination to the next is as accurate as possible.

With the objectives of the DMO in mind, presented in this chapter is a summary of the methodology used for DMO 6, including refinements based on stakeholder feedback from the Issues Paper, as well as directions ACIL Allen has received from the AER.

2.2 Components of the total energy cost estimates

ACIL Allen is required to estimate the Total Energy Costs (TEC) component of the DMO. Total Energy Costs comprise the following components (as shown in Figure 2.1):

— Wholesale energy costs (WEC) for various demand profiles

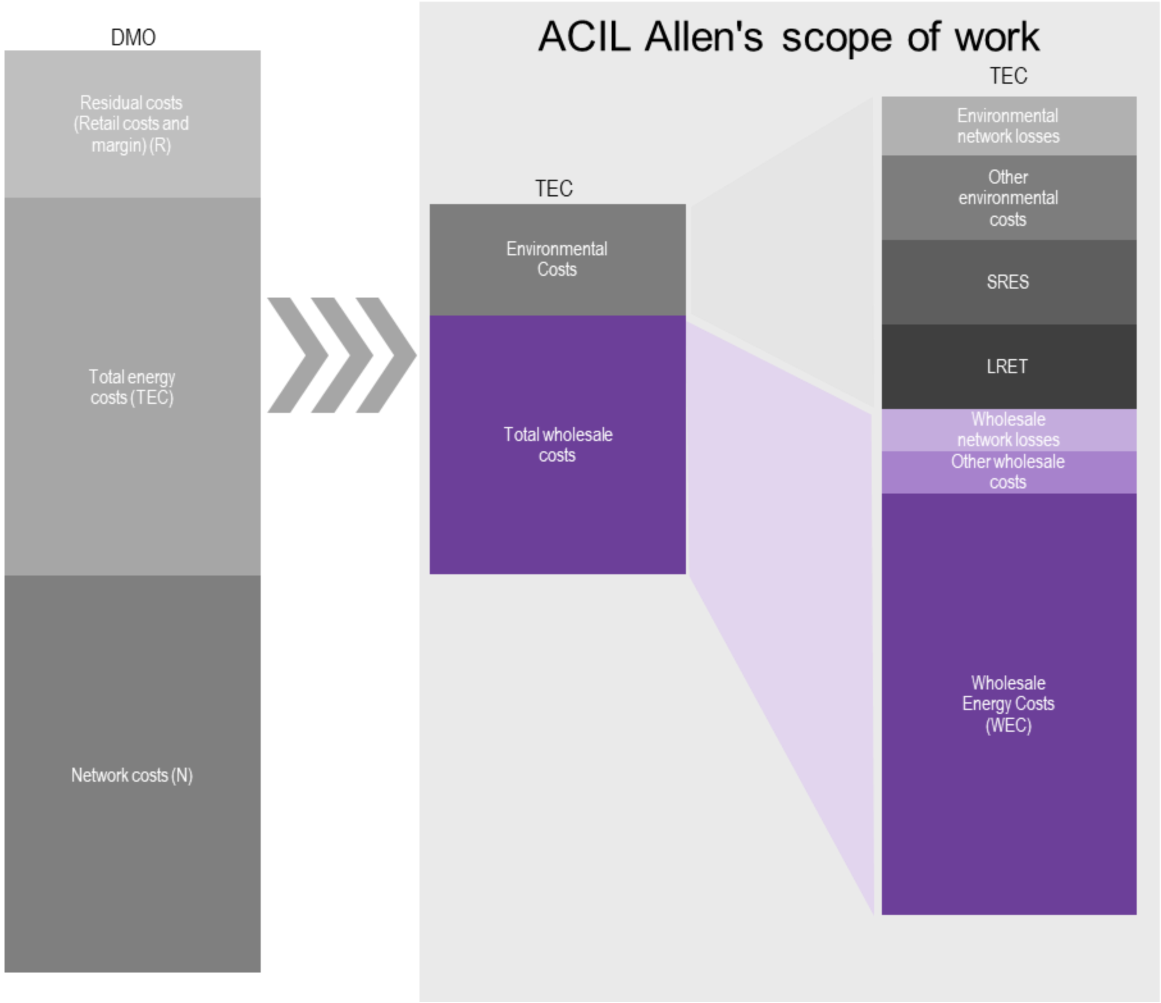
— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET).

— Other wholesale costs: including National Electricity Market (NEM) fees, ancillary services charges, Reliability and Emergency Reserve Trader (RERT) costs, AEMO direction costs, and costs of meeting prudential requirements. In addition, this determination will also account for the known costs associated with the market interventions due to the triggering of administered pricing and spot market suspension that occurred in the NEM in June 2022 that were not finalised at the time of the 2023-24 Final Determination.

— Energy losses incurred during the transmission and distribution of electricity to customers.

— For the purpose of the DMO, the AER has requested ACIL Allen to present the estimates of the TEC components in two broad groupings – Wholesale and Environmental – in the manner shown in Figure 2.1.

Figure 2.1 Components of DMO and TEC



Source: ACIL Allen

2.3 Methodology

The ACIL Allen methodology adopted for DMO 6 (and DMO 2 to 5) estimates costs from a retailing perspective. This involves estimating the energy and environmental costs that an electricity retailer would be expected to incur in a given determination year. The methodology includes undertaking wholesale energy market simulations to estimate expected spot market costs and volatility, and the hedging of the spot market price risk by entering into electricity contracts with prices represented by the observable futures market data. Environmental and other energy costs are added to the wholesale energy costs and the total is then adjusted for network losses.

2.3.1 Estimating the WEC - market-based approach

Energy purchase costs are incurred by a retailer when purchasing energy from the NEM spot market to satisfy their retail load. However, given the volatile nature of wholesale electricity spot prices, which is an important and fundamental feature of an energy-only market (i.e. a market without a separate capacity mechanism), and that retailers charge their customers based on fixed rate tariffs (for a given period), a prudent retailer is incentivised to hedge its exposure to the spot market.

Hedging can be achieved by a number of means – a retailer can own or underwrite a portfolio of generators (the gen-tailer model), enter into bilateral contracts directly with generators, purchase over the counter (OTC) contracts via a broker, or take positions on the futures market. Typically, a retailer will employ a number of these hedging approaches. In addition, a retailer may choose to leave a portion of their load exposed to the spot market.

At the core of the market-based approach is an assumed contracting strategy that an efficient retailer would use to manage its electricity market risks. Such risks and the strategy used to mitigate them are an important part of electricity retailing. The contracting strategy adopted generally assumes that the retailer is partly exposed to the wholesale spot market and partly protected by the procured contracts.

The methodology simulates the cost of hedging by building up a portfolio of hedges consisting of base and peak swap contracts, and cap contracts (and this is discussed in more detail below).

Conceptually, in a given half-hourly settlement period, the retailer:

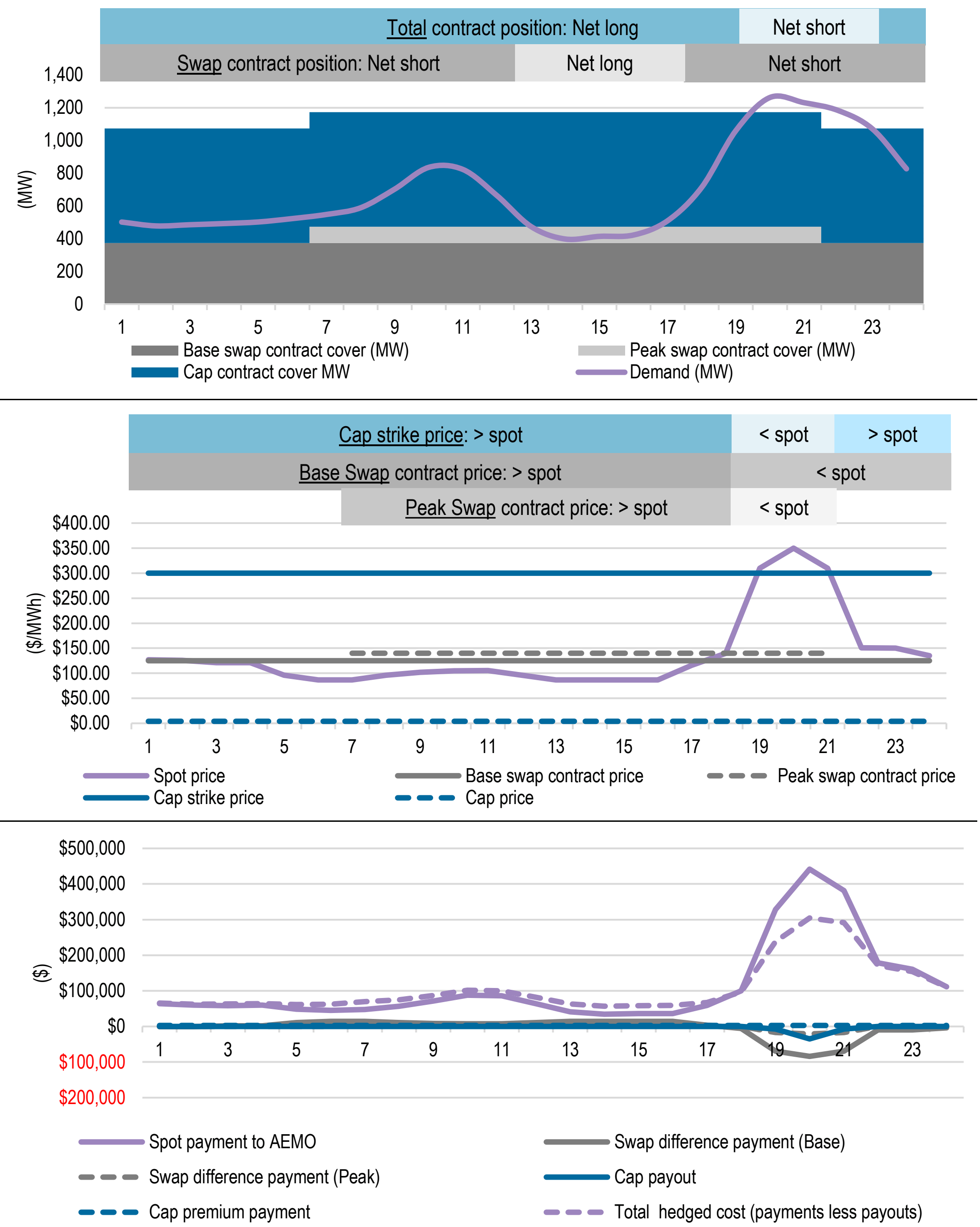
— Pays AEMO the spot price multiplied by the demand.
— Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract during the periods classified as peak. If the spot price is greater than the contract strike price than the counter party pays the retailer.
— Pays the contract counterparty the cap price multiplied by the cap contract quantity.
— If the spot price exceeds $300/MWh, receives from the contract counter party the difference between the spot price and $300, multiplied by the cap contract quantity.

Figure 2.2 shows an illustrative example of a hedging strategy for a given load across a 24-hour period.

In this example:

— The demand profile:
  – Varies between 400 MW and 1,300 MW.
  – Peaks between 6 pm and 10 pm, with a smaller morning peak between 9 am and 11 am.
— The hedging strategy:
  – Consists of 375 MW of base swaps, 100 MW of peak period swaps, and 700 MW of caps.
  – Means that demand exceeds the total of the contract cover between 7 pm and 10 pm by about 100 MW. Hence during these periods, the retailer is exposed to the spot price for 100 MW of the demand, and the remaining demand is covered by the hedges.
  – Demand is less than the hedging strategy for all other hours. Hence, during these periods the retailer in effect sells the excess hedge cover back to the market at the going spot price (and if the spot price is less than the contract price this represents a net cost to the retailer, and vice versa).

Figure 2.2 Illustrative example of hedging strategy, prices and costs



Source: ACIL Allen

With this in mind, the WEC for a given demand profile for a given year is therefore generally a function of four components, the:

1. demand profile
2. wholesale electricity spot prices
3. forward contract prices
4. hedging strategy.

Use of financial derivatives in estimating the WEC

As discussed above, retailers purchase electricity in the NEM at the spot price and use a number of strategies to manage their risk or exposure to the spot market. Market-based approaches adopted by regulators for estimating the WEC make use of financial derivative data given that it is readily available and transparent. This is not to say regulators are of the view that retailers only use financial derivatives to manage risk – it simply reflects the availability and transparency of data.

Some retailers also use vertical integration and Power Purchase Agreements (PPAs) to manage their risk. However, the associated costs, terms and conditions of these approaches are not readily available in the public domain. Further, smaller retailers may not be in a position to use vertical integration or PPAs and hence rely solely on financial derivatives.

Additionally, the value of long-dated assets associated with vertical integration and PPAs is determined by conditions in the market at a given point in time. The price in a PPA or the annualised historical cost of generation reflects the long term value of the generation anticipated at the time of commitment when the investor was faced with a variety of uncertain futures. As a consequence, there are considerable difficulties in using the price of PPAs or the annualised historical cost of generation as a basis for estimating current hedging costs.

In essence, the methodology uses available and transparent financial derivative data as a proxy for the range of other hedging instruments adopted by retailers.

Use of load profiles in estimating the WEC

Our scope of work requires the estimation of the WEC for residential and small business load in each distribution zone.

The following load profiles are required for the given determination year:

- System load for each region of the NEM (that is, the load to be satisfied by scheduled and semi-scheduled generation) – used to model the regional wholesale electricity spot prices.
- Net System Load Profiles (NSLPs), controlled load profiles (CLPs), and interval meter load data for residential and small business customers - used to model the cost of procuring energy for residential and small business customers for the following:
  - New South Wales: Ausgrid, Endeavour, Essential
  - Queensland: Energex
  - South Australia: SAPN.

Historical load data is available from AEMO – as shown in Table 2.1.

ACIL Allen investigated estimating separate WECs for residential and small business customers as part of its methodology review for DMO 3 and reached the conclusion that developing WECs for residential and non-residential customers does not guarantee to improve accuracy due to a lack of readily publicly accessible and quality assured load profile data, and is largely arbitrary. It ignores, and does not account for, the large variety of non-residential load profile shapes that exist and the different mixes of these profiles that each retailer may have, and for some non-residential customers their profile may well be closer related to a residential profile given the nature of their business and hours of operation. Nor does it account for the difference in residential customers with and without rooftop solar PV – which are more likely to have very different load profiles.

Table 2.1 Sources of load data

Region	Distribution Network	Load Type	Load Name	Source
New South Wales	NA	System Load	NSW1	MMS
	Ausgrid	NSLP	NSLP,ENERGYAUST	MSATS
	Ausgrid	Residential and small business customers on interval meters	Ausgrid Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
	Ausgrid	CLP	CLOADNSWCE,ENERGYAUST	MSATS
	Ausgrid	CLP	CLOADNSWEA,ENERGYAUST	MSATS
	Endeavour Energy (Endeavour)	NSLP	NSLP,INTEGRAL	MSATS
	Endeavour	Residential and small business customers on interval meters	Endeavour Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
	Endeavour	CLP	CLOADNSWIE,INTEGRAL	MSATS
	Essential Energy (Essential)	NSLP	NSLP,COUNTRYENERGY	MSATS
	Essential Energy	Residential and small business customers on interval meters	Essential Energy Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
	Essential	CLP	CLOADNSWCE,COUNTRYENERGY	MSATS
Queensland	NA	System Load	QLD1	MMS
	Energex	NSLP	NSLP,ENERGEX	MSATS
	Energex	Residential and small business customers on interval meters	Energex Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
	Energex	CLP	QLDEGXCL31,ENERGEX	MSATS
	Energex	CLP	QLDEGXCL33,ENERGEX	MSATS
South Australia	NA	System Load	SA1	MMS
	SA Power Networks (SAPN)	NSLP	NSLP,UMPLP	MSATS
	SA Power Networks (SAPN)	Residential and small business customers on interval meters	SAPN Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
	SA Power Networks (SAPN)	CLP	CLP,UMPLP	MSATS

Source: AEMO

Use of interval meter data for residential and small business customers

Since the Power of Choice reforms in 2017, new rooftop solar PV installations require the replacement of an existing accumulation meter with a new smart meter[1]. In previous DMOs the NSLP has been used as the representative load profile for residential and small business customers because the majority (about 90 per cent in 2020, and 80 per cent in 2021) of residential and small business customers were on accumulation (or basic) meters. And those customers with interval (or smart) meters were in the minority. However, ACIL Allen estimates the penetration of interval meters in 2022 increased to about 30 per cent, and to about 40 per cent in 2023.

With the likely continued roll out of interval meters due to, in part by retailers responding to various market incentives, the end-of-life replacement of older accumulation meters, and due to the AEMC's recommendation of a target of 100 per cent uptake of smart meters by 2030, it is likely that customers on interval meters will be the majority in the next few years.

In this determination, we have used a combination of the NSLP and interval meter data in our estimation of the WEC. The use of interval meter data improves the estimation of the cost of supplying energy to small customers because the interval meter data in addition to the NSLP better reflects the shape of small customers' load.

There are some considerations in making this recommendation:

— Data transparency: At this stage AEMO does not make interval meter load profile data publicly available on its website. This means, until AEMO publish this data, that the AER will need to proactively request the data in time for each determination, and that the data cannot be readily accessed by stakeholders for verification.

— Data validity: The purpose of the determination is to estimate the WEC from a retailer's perspective. AEMO constructs the NSLP including the 'carve out' of NSLP due to rooftop PV exported to the grid. Inclusion of PV export carve out in the NSLP is not counter to the purpose of the determination given that retailers are charged by AEMO based on the NSLP. However, for customers on interval meters, presumably it would be the energy drawn from the grid that ought to be included in the WEC estimation process, that is, rooftop solar PV exports ought to be removed from the data as these are treated separately by retailers. ACIL Allen understands that prior to the introduction of five-minute settlement (5MS) in October 2021, interval meter load data is available on an aggregate basis – that is, it includes exports from rooftop PV which cannot be readily separated from the load. Post 5MS, the data is separated into load drawn from the grid and solar exports injected to the grid.

— Step change in WEC estimates: If the aggregate load profile of customers on interval meters is different to that of customers on the NSLP, then delaying the aggregation of the interval meter load data into the WEC estimation process runs the risk of a step change in WEC from one year to the next (all other things equal), whereas including the interval meter load data sooner when it represents a smaller proportion of customers will result in a modest change.

ACIL Allen is of the view that it is better to commence using the interval meter data in combination with the NSLP data sooner rather than later as it removes the risk of a step change in WEC estimate. Further, the interval meter data post-5MS, allows for the separation of rooftop PV exports.

Therefore, for the 2024-25 determination we have been able to exclude the PV export carve out by using more recent post-5MS interval meter load data supplied by AEMO, and have aggregated the NSLP and interval meter data for small customers.

[1] In this report, smart meter is used interchangeably with interval meter for the purposes of estimating load profiles. That is, interval/smart meters record how much electricity is used in each NEM settlement period, versus accumulation meters which track total electricity usage at any point in time.

Key steps to estimating the WEC

The key steps to estimating the WEC for a given load and year are:

1. Forecast the hourly load profile – generally as a function of the underlying demand forecast as published by the Australian Energy Market Operator (AEMO), and accounting for further uptake of rooftop solar PV. A stochastic demand and renewable energy resource model to develop 53 weather influenced annual simulations of hourly demand and renewable energy resource traces which are developed so as to maintain the appropriate correlation between the various regional and NSLP/CLP/interval meter demands, and various renewable energy zone resources.
2. Use a stochastic availability model to develop 11 annual simulations of hourly thermal power station availability.
3. Forecast hourly wholesale electricity spot prices by using ACIL Allen's proprietary wholesale energy market model, *PowerMark*. *PowerMark* produces 583 (i.e. 53 by 11) simulations of hourly spot prices of the NEM using the stochastic demand and renewable energy resource traces and power station availabilities as inputs.
4. Estimate the forward contract price using ASX Energy contract price data, verified with broker data. The book build is based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price.
5. Adopt an assumed hedging strategy – the hedging strategy represents a strategy that a retailer would undertake to hedge against risk in the spot price in a given year. It is generally assumed that a retailer's risk management strategy would result in contracts being entered into progressively over a two- or three-year period, resulting in a mix (or portfolio) of base (or flat), peak and cap contracts.
6. Calculate the spot and contracting cost for each hour and aggregate for each of the 583 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

The above steps produce a distribution of estimated WECs which vary due to variations in demand, and spot prices. Wholesale electricity spot prices will vary depending on the actual load (which will vary based on weather conditions), renewable generator resource (which also varies with weather outcomes), and availability of thermal power stations. It is this variability, and associated risk, that incentivises retailers to enter into hedging arrangements. However, this variability also changes the values of the spot purchase costs and difference payments incurred by a retailer (even though the contract prices and strategy are fixed).

The distribution of outcomes produced by the above approach is then analysed to provide a risk assessed estimate of the WEC. In earlier determinations, ACIL Allen adopted the 95th percentile WEC from the distribution of WECs as the final estimate. In practice, the upper part of the distribution of WECs from the simulations exhibits a relatively narrow spread when compared to estimates based on the load being 100 per cent exposed to the spot market, which is to be expected since they are hedged values. The shape of the distribution of hedged values tends to be the mirror image of the shape of the distribution of spot values, since a spot price spike will result the retailer receiving a large difference payment if its hedge position is greater than its load. Choosing the 95th percentile reduces the risk of understating the true WEC, since only five per cent of WEC estimates exceed this value. However, for this current Determination, and consistent with the Final Determinations of DMO 4 and DMO 5, the AER has determined that the 75th percentile WEC be adopted.

Choosing the appropriate hedging strategy

As mentioned above, multiple hedging strategies are tested by varying the mix of base/cap contracts for each quarter. This is done by running the hedge model for a large number[2] of simulations for each strategy and analysing the resulting distribution of WECs for each given strategy – and in particular, keeping note of the 95th percentile WEC for each strategy. We select a strategy that is robust and plausible for each load profile, and minimises the 95th percentile WEC, noting that:

— some strategies may be effective in one year but not in others
— in practice, retailers do not necessarily make substantial changes to the strategy from one year to the next
— our approach is a simplification of the real world, and hence we are mindful not to over-engineer the approach and give a false sense of precision.

The hedging strategy is not necessarily varied for every determination year – it tends to change when there is a sufficient change in either the shape of the load profile (for example, due to the continued uptake of rooftop PV) or a change in the relationship between contract prices for the different contract products (for example, in some years base contract prices increase much more than peak contract prices, which can influence the strategy).

Demand-side settings

The seasonal peak demand and annual energy forecasts for the regional demand profiles are referenced to the central scenario from the latest available Electricity Statement of Opportunities (ESOO) published by AEMO and take into account past trends and relationships between the NSLPs and interval meter loads and the corresponding regional demand.

It is usual practice to use a number of years of historical load data together with the P10, P50 and P90 seasonal peak load, and energy forecasts from the AEMO neutral scenario to produce multiple simulated representations of the hourly load profile for the given determination year using a Monte Carlo analysis. These multiple simulations include a mix of mild and extreme representations of demand – reflecting different annual weather conditions (such as mild, normal and hot summers).

The key steps in developing the demand profiles are:

— The half-hourly demand profiles of the past two[3] years are obtained. The profiles are adjusted by 'adding' back the estimated rooftop PV generation for the system demand and each NSLP and interval meter load profile (based on the amount of rooftop PV in each distribution network).
— A stochastic demand model is used to develop about 53 weather influenced simulations of hourly demand traces for the NSLPs and interval meter loads, each regional demand, and each renewable resource – importantly maintaining the correlation between each of these variables. The approach takes the past three years of actual demand data, as well as the past 53 years of weather data and uses a matching algorithm to produce 53 sets of weather-related demand profiles of 17,520 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead, it accepts there is a relationship and uses a matching algorithm to find the closest matching weather outcomes for a given day across the entire NEM from the past three years to represent a given day in the past.

[2] When testing the different strategies, we do not run the full set of 583 simulations as this is time prohibitive. However, we run the full set of 583 simulations once the strategy has been chosen.

[3] Normally we use two to three years of data, however for this determination, we have used data covering 1 October 2021 to 30 June 2023 as this allows for the inclusion of interval meter load data from which we are able to exclude the PV export carve out.

- The set of 53 simulations of regional system demands is then grown to the AEMO demand forecast using a non-linear transformation so that the average annual energy across the 53 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 53 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 seasonal peaks from the AEMO demand forecast.
- A relationship between the variation in the NSLPs and interval meter load profiles, and the corresponding regional demand from the past two years is developed to measure the change in NSLP and interval meter load as a function of the change in regional demand. This relationship is then applied to produce 53 simulations of weather related NSLP and interval meter load profiles of 17,520 half-hourly loads which are appropriately correlated with system demand, but also exhibit an appropriate level of variation in the NSLP and interval meter load across the 53 simulations.
- The projected uptake of rooftop PV for the determination year is obtained (using our internal rooftop PV uptake model).
- The half-hourly rooftop PV output profile is then grown to the forecast uptake and deducted from the system demand, NSLPs and interval meter loads.

Adjustment to the Energex and SAPN NSLP demand data used in the analysis

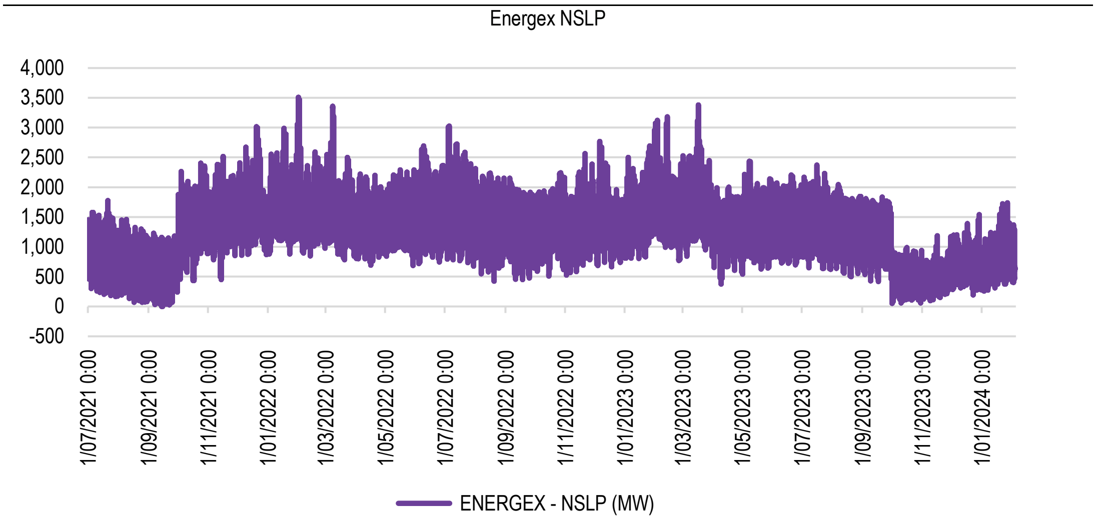
An important input to estimate the WEC 2024-25 is the load trace for small customers. The shape of the load trace and its variability, together with spot price levels, shape and volatility, influences how a retailer manages risk for this segment of the market.

Therefore, an appropriate representation of the load trace of small customers to be served by retailers in 2024-25 is required to estimate the WEC as accurately as possible. The more accurate the load trace representation for 2024-25, the more accurate the WEC estimate.

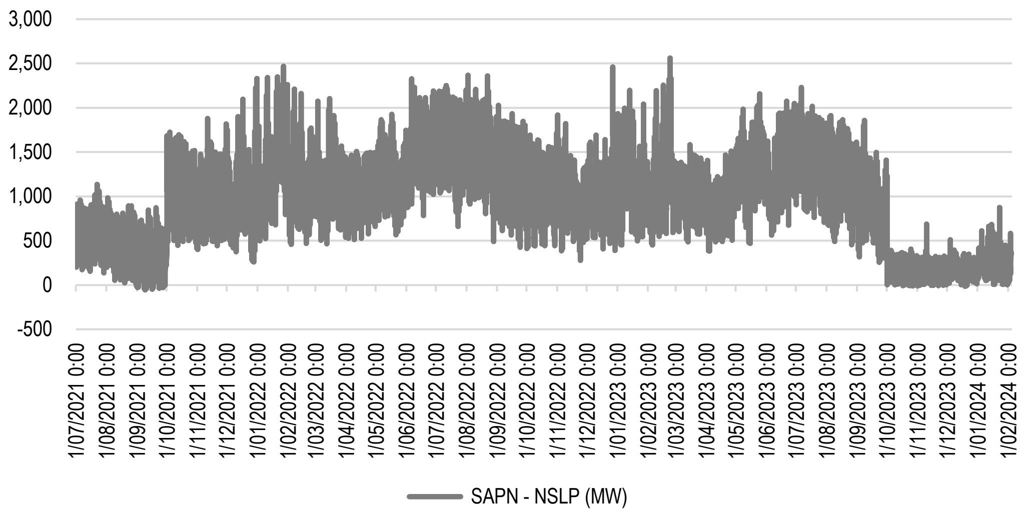
Typically, the methodology uses the past two to three years of actual NSLP load trace data to generate multiple representations of the load trace for the given determination year. Adopting this usual approach would mean using actual NSLP data spanning 1 July 2021 to 30 June 2023.

However, as shown in Figure 2.3 we observe that between 1 October 2021 and 30 September 2023 there was a step change in the NSLP load trace for Energex and SAPN.

Figure 2.3 Energex and SAPN NSLP (MW) – July 2021 to January 2024



SAPN NSLP



Source: ACIL Allen analysis of AEMO data

The cause for this step change was not due to a sudden change in consumer behaviour or consumption patterns. The cause was AEMO making an adjustment to manage an issue relating to negative demand values coinciding with the commencement of 5MS. AEMO's adjustment resulted in an "artificial uplift" to the Energex and South Australia NSLP traces during this period.

This artificial uplift would have impacted how AEMO settled the NSLP with retailers during the period 1 October 2021 and 30 September 2023. However, we observe, and AEMO notes, that this artificial uplift was temporary and ceased from 1 October 2023.

This means the artificial uplift will not impact retailers in 2024-25.

Therefore, we identify three options for developing a set of representative load traces for 2024-25:

1. Take the usual approach and use the actual NSLP data spanning 1 July 2021 to 30 June 2023. This would mean that the simulated load traces for 2024-25 will include the temporary artificial uplift. Plainly this is inaccurate since the artificial uplift ceased from 1 October 2023 and will not be present in 2024-25. Further, the temporary artificial uplift applied to the Energex and SAPN NSLPs only, and therefore continuing to include the uplift would result in 2024-25 WEC estimates for these two networks inconsistent with those of the New South Wales networks[4].
2. Use older NSLP data prior to the temporary artificial uplift to represent the NSLP load trace in 2024-25. This would mean using data from 1 July 2019 to 30 June 2021. This data is between 3 to 5 years old and runs the risk of not representing the trace for 2024-25 given the movement of small customers away from the NSLP due to the ramp up in the rollout of interval meters. It also means that the spot price modelling will be based on system load trace data that is also 3 to 5 years old (recalling that to maintain internal consistency between the spot price modelling and hedge model is critical to use coincident NSLP and system demand traces from the same period).
3. Use the latest available NSLP data as per option 1, but remove the artificial uplift given it will not be present in 2024-25. This has the advantage of using the latest available data which will also

[4] It could be argued that the temporary artificial uplift should have been included in the WEC estimation process of the previous determinations spanning the period of the uplift. However, the WEC estimation process is forward looking and there was no indication that this uplift would occur for earlier determinations. Regarding the 2023-24 determination, AEMO delayed the publication of the NSLP data impacted by the uplift by about nine months, with the data not published until late in December 2022, which meant it was not possible to include the data in the determination process in a timely manner with confidence that data were correct.

allows for the pairing up with the latest available interval meter load trace data, and also means the spot price modelling is based on the latest system demand traces.

On balance, it is ACIL Allen's view that option 3 is the appropriate option to adopt.

By adopting option 3, the temporary artificial step change in the NSLP needs to be removed. This is done by calculating an adjustment based on the observed change (in terms of magnitude and spread) in NSLP demands between the three months prior to the artificial uplift (preuplift) and the first three months with the artificial uplift (postuplift). This time period is chosen to calculate the adjustment because it minimises the risk of including other fundamental change in consumer demand patterns. Using a longer period of data to calculate the adjustment factor could include changes unrelated to the temporary artificial uplift, such as the continued uptake of rooftop PV or rollout of interval meters.

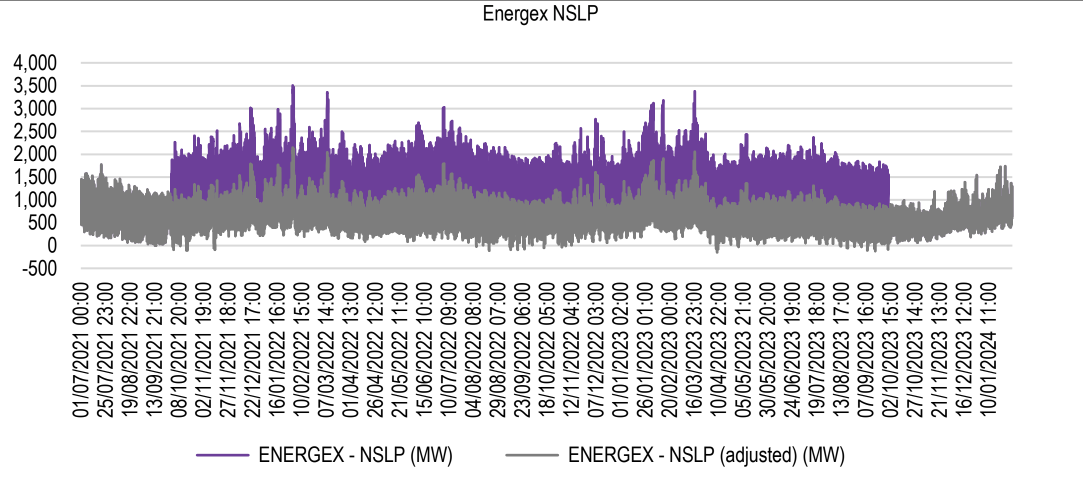
The adjustment is then applied to the Energex and SAPN NSLP loads over the entire period of the temporary artificial uplift to remove the uplift.

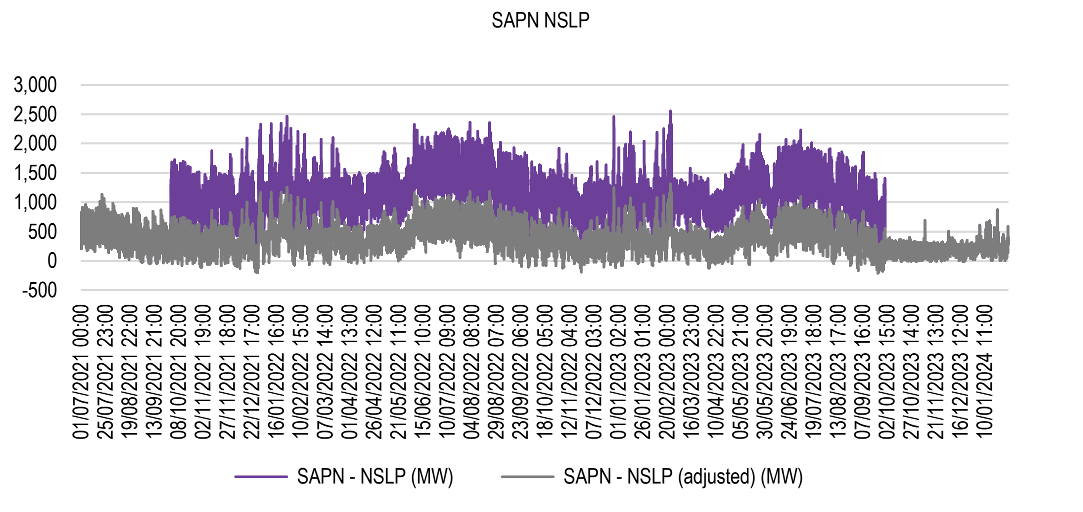
The adjustment is the standard statistical distribution transformation formula:

$$Demand_{New} = Average\_Demand_{Preuplift} + (Demand_{Postuplift} – Average\_Demand_{Postuplift}) * (StDDev\_Demand_{Preuplift} / StdDev\_Demand_{Postuplift})$$

Figure 2.4 and Figure 2.5 show the effect of the adjustment which results in a profile not dissimilar to the shape of the NSLP prior to AEMO applying the temporary artificial uplift.

Figure 2.4 Energex and SAPN NSLP (MW) – July 2021 to January 2024

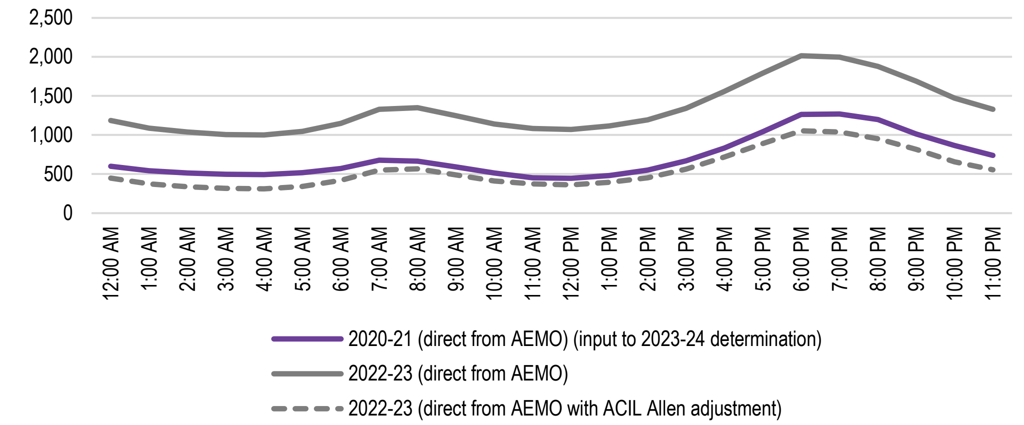




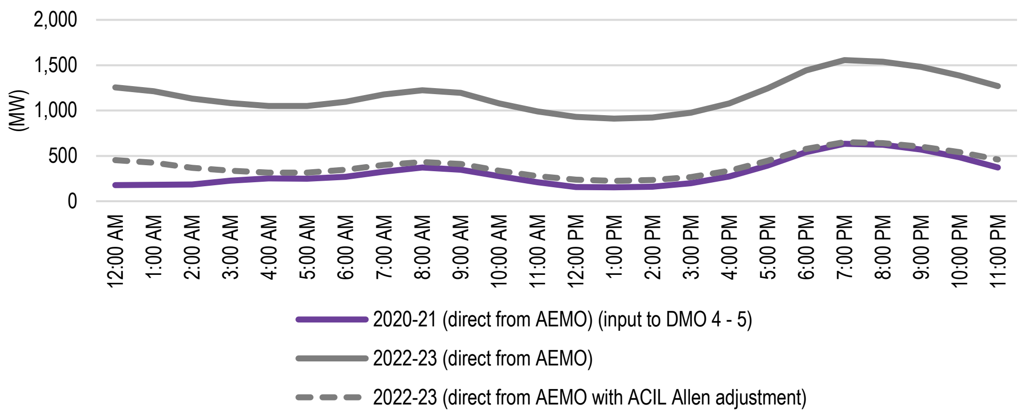
Source: ACIL Allen analysis of AEMO data

Figure 2.5 Average time of day profile (MW) – Energex and SAPN NSLP

Energex NSLP



SAPN NSLP



Source: ACIL Allen analysis of AEMO data

Box 2.1 NSLP and interval meter demand data used to estimate the WEC

Our recommendation is to calculate the WEC based on the blend of the adjusted NSLP (that is, with the temporary artificial step change removed for Energex and SAPN), and the interval meter demand data with rooftop PV exports removed from the interval meter demand data (recalling that PV exports cannot be separated from the NSLP data).

However, the AER has asked ACIL Allen to also calculate the WEC for the blended profile with the temporary artificial uplift to the NSLP remaining in place for 2024-25 for Energex and SAPN (referred to as the unadjusted NSLP in this report). The WECs and TECs estimated based on these profiles are presented separately in Table 4.5 in section 4.2.4 and Table 4.35 in section 4.6 respectively.

Please note however, that the supporting analyses presented in this report relating to the WEC and TEC estimates for 2024-25 are based on our recommendation of removing the temporary artificial uplift from the Energex and SAPN NSLP.

Source: ACIL Allen

Supply side settings

ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2024-25 we use our December 2023 Reference case projection settings which, in the short term, are closely aligned with AEMO's Integrated System Plan (ISP) and ESOO. Table 2.2 summarises the key assumptions adopted in the Reference case for the spot price modelling pertinent for the 2024-25 period.

ACIL Allen incorporates changes to existing supply where companies have formally announced the changes – including, mothballing, closure and change in operating approach. Near term new entrants are included where the plants are deemed by ACIL Allen to be committed projects.

Table 2.2 Overview of key modelling assumptions relevant for 2024-25

<table>
<tr><th>Assumption</th><th colspan="4">Details</th></tr>
<tr><td>Macro-economic variables</td><td colspan="4">— Exchange rate of AUD to USD 0.7 AUD/USD for 2024-25.
— The brent crude oil price is assumed to converge from current levels to USD65/barrel by the mid-2020s and remain at this level in the long-term.
— International thermal coal prices are assumed to converge from current levels of about USD$150/t to USD$120/t by 2024.</td></tr>
<tr><td>Electricity demand</td><td>Underlying demand
— Equivalent to AEMO 2023 ESOO Central scenario (energy and peak demand)</td><td>Rooftop PV
ACIL Allen’s in-house model of Rooftop PV uptake:
— NEM-wide Rooftop PV uptake is within 5 per cent of AEMO’s Central forecast in 2024-25.</td><td>Behind-the-meter BESS
ACIL Allen’s in-house model of behind-the-meter BESS uptake (linked to rooftop PV model):
— Modest uptake in 2024-25.</td><td>Electric vehicles
— Equivalent to AEMO 2023 ESOO Central scenario</td></tr>
<tr><td>Electricity supply (beyond new supply driven by state based schemes)</td><td>Committed projects
— Named new entrant projects are included in the modelling where there is a high degree of certainty that these will go ahead (i.e. project has reached financial close)</td><td colspan="3">Assumed new entry and closures
Committed or likely committed generator closures included where the closure has been announced by the participant (Eraring in 2025).</td></tr>
<tr><td>Gas prices into gas-fired power stations</td><td colspan="4">For 2024-25, it is assumed that gas prices are capped at $12/GJ as part of the Government’s response to high electricity prices. However, the modelling assumes the price cap applies to CCGT plant and not peaking plant. Peaking plant are assumed to purchase their marginal gas on a short term basis at a price of $20/GJ (including transport costs) and hence are exempt from the price cap.</td></tr>
<tr><td>Coal prices into coal-fired power stations</td><td colspan="4">ACIL Allen’s in-house understanding of the cost of thermal coal to the NEM’s coal-fired power stations, based on existing contracts with domestic mines and the plant’s exposure to the international export market. For 2024-25, domestic coal prices are assumed to be AUD$135/tonne.</td></tr>
<tr><td>Marginal loss factors</td><td colspan="4">ACIL Allen’s projections of average annual marginal loss factors (MLF) by generator DUID, developed using commercial power flow software.</td></tr>
</table>

Constraints	— Thermal constraints which impact renewable energy zones and result in generator curtailment greater are included in the Reference case modelling. Stability limit constraints which have a material impact on **interstate flows** and regional prices during peak periods are also included.
Generator availability	PowerMark includes a planned maintenance schedule and a set of random unplanned outages for each generator: — The latest MTPASA available at the time the Reference case is developed is adopted for planned maintenance. — For coal plant, an availability of broadly 75-85 per cent based on analysis of coal generator performance. This varies for each generator depending on age of the plant and recently observed outcomes. — Black coal plants are generally assumed to have planned maintenance schedules that equate to about one month every two years. — The brown coal plant tend to have a schedule that equates to one month every four years and the older brown coal plant a schedule that equates to one month every year. — For mid merit gas plant, about 95 per cent based on annual maintenance requirements and assumed forced outage rates. — For peaking plant, a 1.5 per cent forced outage rate. Although peaking plant undergo planned maintenance, we assume that this maintenance is scheduled during the off-peak months when the plant are rarely used. — For hydro plant, an overall availability of 95 per cent per year.

Source: ACIL Allen

2.3.2 New committed supply

Table 5.2 shows the near-term entrants that ACIL Allen considers committed projects and are therefore included in the Reference case. These projects are not yet registered in the market but are expected to come online in the near-term future.

Table 2.3 Near-term addition to supply

ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
1	NSW1	Rye Park WF	Wind	396	Q1 2024
2	NSW1	Flyers Creek WF	Wind	145	Q1 2024
3	QLD1	Kidston Storage Hydro	Pumped Hydro	250	Q3 2024
4	QLD1	Macintyre Wind Farm	Wind	923	Q4 2024
5	QLD1	Wambo WF	Wind	250	Q1 2024
6	QLD1	Karara WF	Wind	103	Q1 2024
7	SA1	Goyder South WF	Wind	100	Q3 2024
8	NSW1	Wollar Solar Farm	Solar	280	Q2 2024
9	NSW1	Wellington North Solar Farm	Solar	300	Q3 2024
10	VIC1	Wunghnu Solar Farm	Solar	80	Q3 2024
11	NSW1	Waratah Super Battery	Battery	850	Q1 2025
12	NSW1	Stubbo Solar Farm	Solar	400	Q1 2024
13	QLD1	Tarong West Wind Farm	Wind	500	Q1 2026
14	VIC1	Kiamal Solar Farm Stage 2	Solar	150	Q1 2025
15	VIC1	Glenrowan Solar Farm	Solar	102	Q1 2024
16	VIC1	Derby Solar Farm	Solar	95	Q1 2024
17	VIC1	Fulham Solar Farm	Solar	80	Q1 2025
18	VIC1	Frasers Solar Farm	Solar	77	Q1 2024
19	VIC1	Horsham Solar Farm	Solar	118.8	Q1 2025
20	VIC1	Derby Battery	Battery	85	Q1 2025
21	VIC1	Fulham Battery	Battery	80	Q1 2025
22	VIC1	Kiamal Battery	Battery	150	Q1 2025
23	VIC1	Horsham Battery	Battery	50	Q1 2025
24	QLD1	Herries Range Wind Farm	Wind	1000	Q1 2026
25	VIC1	Golden Plains Wind Farm	Wind	756	Q3 2025
26	QLD1	Western Downs Battery	Battery	200	Q3 2024
27	SA1	Blyth Battery	Battery	200	Q4 2024
28	NSW1	Liddell Battery	Battery	250	Q1 2025
29	VIC1	Gnarwarre Battery	Battery	250	Q1 2025
30	VIC1	Mortlake Battery	Battery	300	Q1 2025
31	SA1	Bungama Battery	Battery	200	Q3 2024
32	QLD1	Mt Fox Battery	Battery	300	Q1 2025
33	NSW1	Walla Walla Solar Farm	Solar	300	Q2 2024

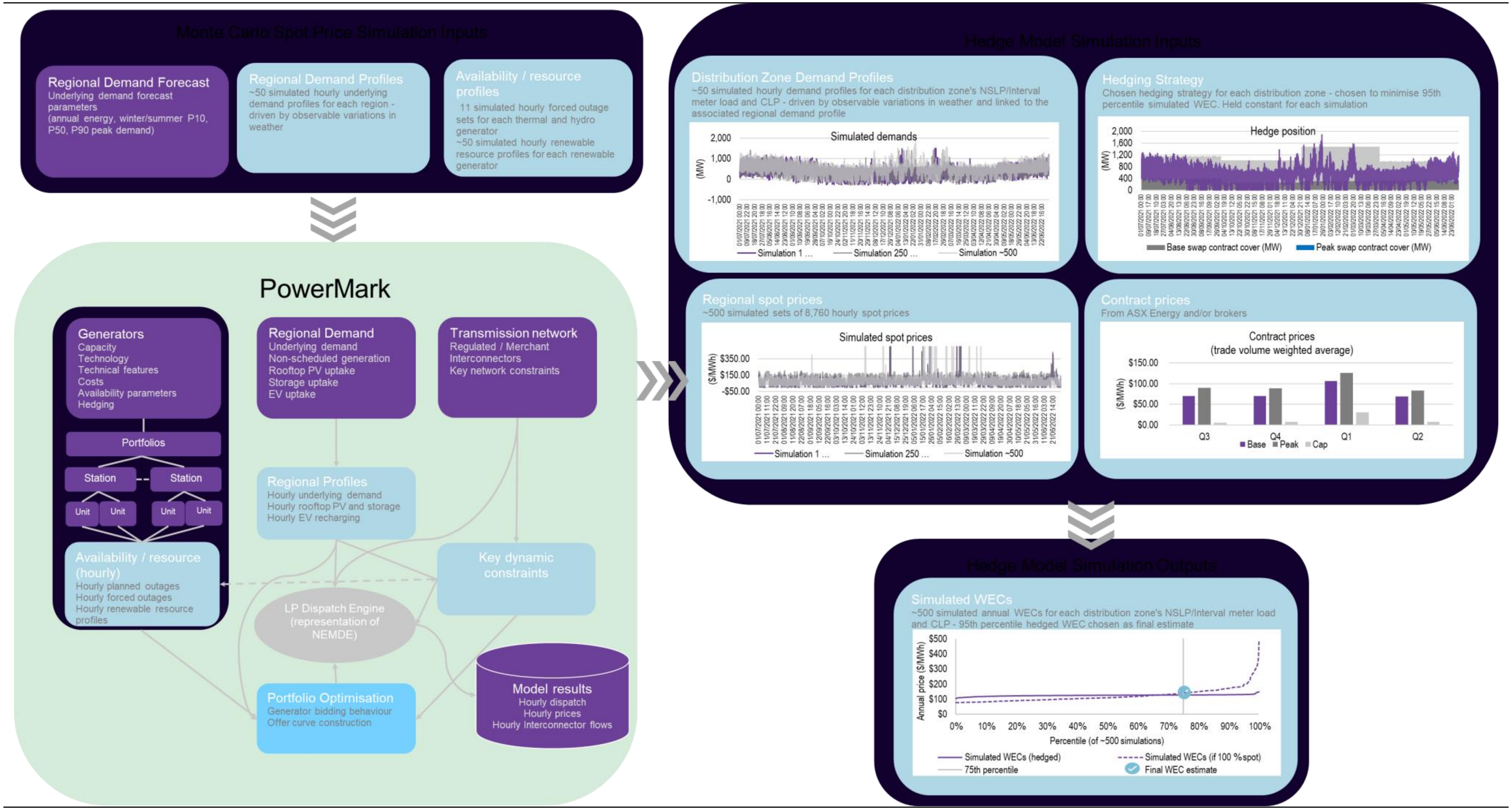
ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
34	NSW1	Big Canberra Battery Discharge	Battery	250	Q1 2026
35	VIC1	Rangebank Battery Discharge	Battery	200	Q1 2025
36	NSW1	Coppabella Wind Farm	Wind	275	Q1 2024
37	NSW1	Limondale Battery Discharge	Battery	50	Q1 2026
38	VIC1	Girgarre Solar Farm	Solar	93	Q3 2024
39	NSW1	New England Solar Farm Stage 2	Solar	320	Q1 2026
40	QLD1	Ardranda photovoltaic	Solar	175	Q1 2025
41	QLD1	Ardranda Battery	Battery	200	Q1 2025
42	QLD1	Aldoga Solar Farm	Solar	380	Q4 2025
43	QLD1	Chinchilla Battery	Battery	100	Q1 2024
44	QLD1	Brigalow Peaking Power Plant	Natural gas	400	Q1 2026
45	VIC1	Koorangie Energy Storage System	Battery	185	Q2 2025
46	SA1	Mannum Solar Farm 2	Solar	30	Q4 2023
47	QLD1	Moah Creek Wind Farm	Wind	372	Q3 2025
48	NSW1	Orana BESS	Battery	415	Q4 2025
49	NSW1	Smithfield BESS	Battery	65	Q4 2025
50	VIC1	The Melbourne Renewable Energy Hub	Battery	600	Q4 2025

Source: ACIL Allen

Summary infographic of the approach to estimate the WEC

Figure 2.6 provides an illustrative infographic type summary of the data, inputs, and flow of the market-based approach to estimating the WEC.

Figure 2.6 Estimating the WEC – market-based approach



WEC estimation accuracy

The estimated WEC for any determination will invariably be different to the actual WEC incurred. This will be a function of several factors, including the actual hedging strategy adopted by a retailer (noting different retailers may have different strategies) compared with the simplified hedging strategy adopted in the methodology, the actual load profiles, spot price and contract price outcomes.

Although we attempt to minimise the error of the estimate by undertaking a large number of simulations to account for variations in weather related demand, thermal plant availability, renewable energy resource, and spot price outcomes, the methodology does not attempt to predict the final trade weighted average contract price for each of the assumed contract products adopted in the hedging strategy. Instead, the methodology relies on contract data available at the time the Determination is made.

Contract prices are a key driver of the WEC estimate. In some years, contract prices may increase after the Final Determination is made, in other years they may decrease, and in some cases, they may remain relatively stable. Figure 2.7 provides three examples of this phenomenon for quarter one base contracts in Queensland over the past four years. The graphs show the daily contract prices, the moving trade weighted average price, as well as the trade weighted average price at the time of the respective Final Determination.

After the date the 2019-20 Final Determination was made, Q1 2020 traded prices increased slightly and then decreased slightly resulting in an actual trade weighted average price very similar to that used in the Final Determination. This is an example of a stable market price environment (at least in terms of the trade weighted average price) – resulting in a reasonably close estimate.

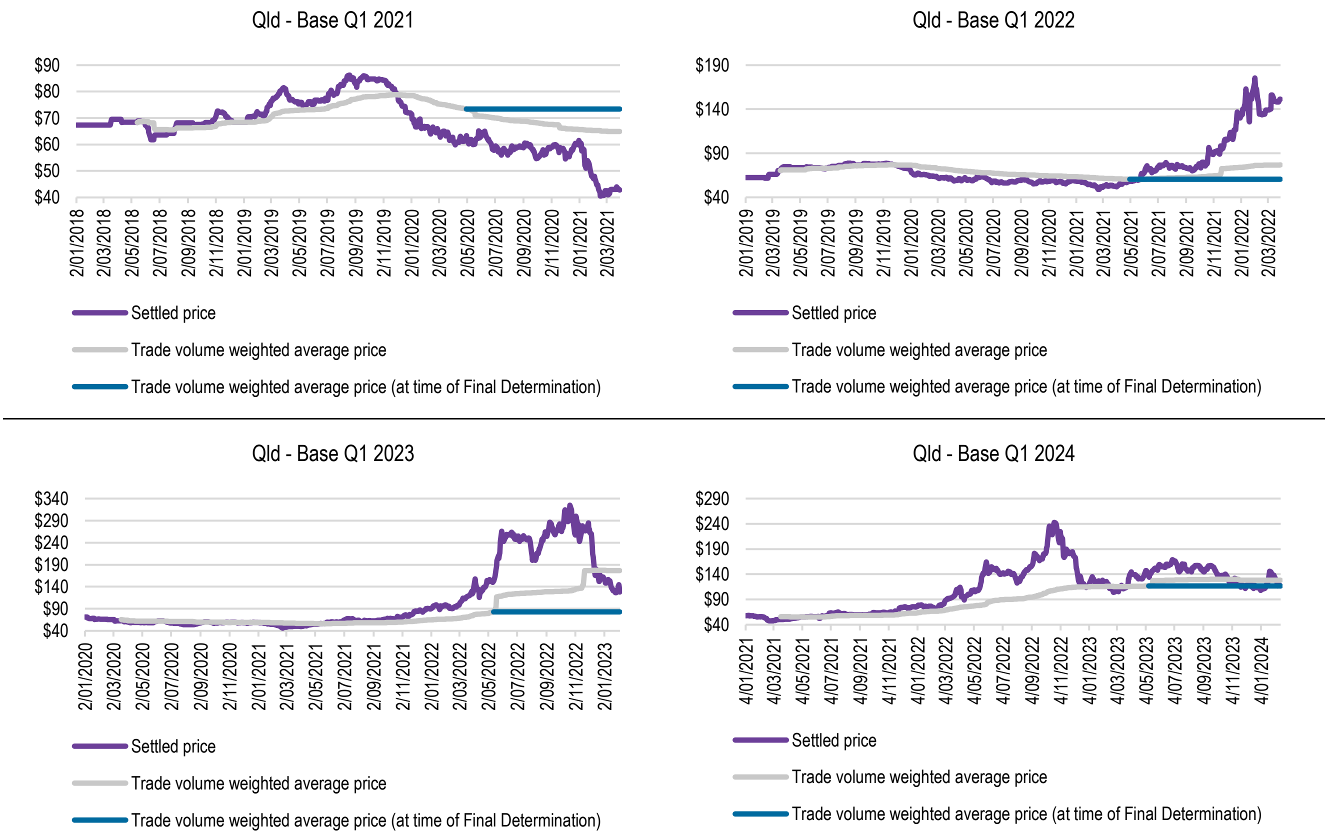
After the date the 2020-21 Final Determination was made, Q1 2021 traded prices decreased consistently resulting in an actual trade weighted average price about $8.50 lower than that used in the Final Determination. This is an example of a decreasing market price environment – resulting in an overestimate of the WEC (all other things equal).

After the date the 2021-22 Final Determination was made, Q1 2022 traded prices increased consistently resulting in an actual trade weighted average price about $17.00 higher than that used in the Final Determination. This is an example of an increasing market price environment – resulting in an underestimate of the WEC (all other things equal).

After the date the 2022-23 Final Determination was made, Q1 2023 traded prices increased substantially resulting in an actual trade weighted average price about $90.00 higher than that used in the Final Determination. This is another, and more extreme, example of an increasing market price environment – resulting in a substantial underestimate of the WEC (all other things equal).

After the date the 2023-24 Final Determination was made, Q1 2024 traded prices increased slightly and then decreased slightly resulting in an actual trade weighted average price very similar to that used in the Final Determination. This is an example of a relatively stable market price environment post Final Determination (at least in terms of the trade weighted average price) – resulting in a reasonably close estimate.

Figure 2.7 Daily settlement prices and trade volume weighted prices ($/MWh) for Q1 base contracts in Queensland



Source: ACIL Allen analysis of ASX Energy data

The graphs in Figure 2.7 demonstrate a number of important points about the WEC estimation methodology:

— It is much easier to estimate the WEC during periods of market and contract price stability.

— It is much more challenging to estimate the WEC during periods of increasing or decreasing contract prices.

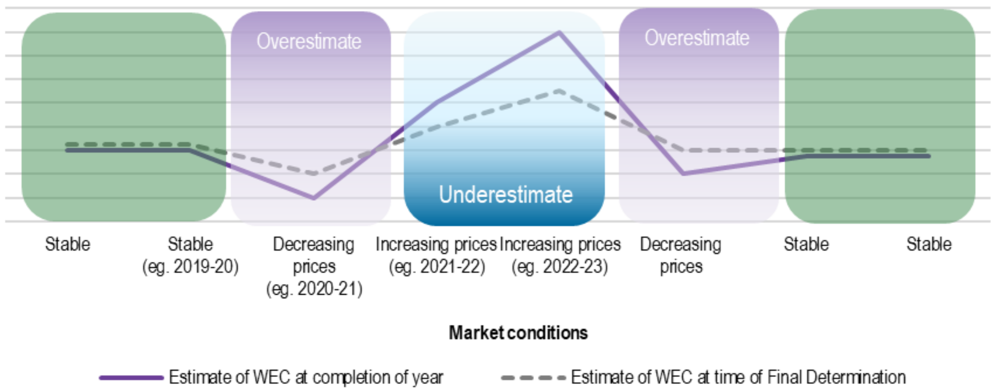
— The error in the WEC estimate, due to contract price variation, is likely to be greater in an environment of increasing prices, than it is in an environment of decreasing prices. This is because of the skewed nature of wholesale electricity prices in the NEM – prices can increase a lot more than they can decrease – and demonstrates the risk faced by retailers. This is another reason to adopt a higher percentile of the simulated WECs.

— Adopting a bookbuild period from the date of the first trade, rather than artificially constraining it to a shorter time frame, means that the trade weighted average contract price has a greater chance of smoothing out temporary fluctuations in contract prices.

In some years contract prices will increase, and in others they will decrease after the Final Determination is made. It is unlikely that the market will enter into an extended period of seemingly ever-increasing or -decreasing prices – at some point, the market will respond accordingly with investment and/or retirement of capacity.

Hence, it is likely that over the long run, the market will follow some form of pattern of increasing, decreasing and stable price outcomes. With this in mind, the methodology may well result in a comparatively smooth WEC estimate trajectory – underestimating outcomes in an increasing price environment, and overestimating outcomes in a decreasing price environment – as illustrated in Figure 2.8.

Figure 2.8 Illustrative comparison of WEC estimation accuracy given market environment



Source: ACIL Allen

2.3.3 Other wholesale costs

Market fees and ancillary services costs

Market fees and ancillary service costs are estimated based on data and policy documents published by AEMO.

NEM fees

NEM fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA), DER, and IT upgrade costs associated with 5MS.

The approach for estimating market fees is to make use of AEMO's latest budget report. AEMO's 2023-24 budget report was released in June 2023 and adopted for the Draft Determination. If available, we will use AEMO's 2024-25 budget report for the Final Determination.

Consistent with all previous determinations, fees published in AEMO's budget that are expressed as a cost per connection per week, are converted to $/MWh terms by multiplying the cost by the number of connections and weeks per year, and then dividing by the customer load forecast (all of which are provided in the AEMO budget report).

Ancillary services charges

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability. AEMO recovers the costs of these services from market participants. These fees are published by AEMO on its website on a weekly basis.

The approach used for estimating ancillary services costs is to average the most recent 52 weeks of costs to recover ancillary services from customers, which is published on the AEMO website. This is done on a region-by-region basis.

Prudential costs

Prudential costs, for AEMO, as well as representing the capital used to meet prudential requirements to support hedging take into account:

— the AEMO assessed maximum credit limit (MCL)
— the future risk-weighted pool price
— participant specific risk adjustment factors

— AEMO published volatility factors
— futures market prudential obligation factors, including:
— the price scanning range (PSR)
— the intra month spread charge
— the spot isolation rate.

Prudential costs are calculated for each NSLP. The prudential costs for the NSLP are then used as a proxy for prudential costs for the controlled load profiles.

AEMO publishes volatility factors two years in advance. Similarly, ASX Energy publishes initial margin parameters two years in advance.

AEMO prudential costs

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

— bank guarantees
— reallocation certificates
— prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = OSL + PML

Where for the Summer (December to March), Winter (May to August) and Shoulder (other months):

OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x (GST + 1) x 35 days

PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x (GST + 1) x 7 days

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5 percent annual charge for 42 days or 2.5%*(42/365) = 0.288 percent.

Hedge prudential costs

ACIL Allen relies on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The money market rate used in this analysis is 3.10 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

We understand that the initial margin is set based on three parameters being:

— the price scanning range (PSR) expressed as a percentage of the contract face value and is set for each of the base, peak and cap contract types
— the intra monthly spread charge and is set for each of the base, peak and cap contract types
— the spot isolation rate and is set for each of the base, peak and cap contract types.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter. This is divided by the average hours in the given quarter. Then applying an assumed funding cost but adjusted for an assumed return on cash lodged with the clearing results in the prudential cost per MWh for each contract type.

Reliability and Emergency Reserve Trader (RERT)

Given the RERT is called upon under extreme circumstances only, ACIL Allen is of the opinion that it is difficult to project into the future. Although it may be possible to make use of previous costs of the RERT and relate these to AEMO's projection of USE in the ESOO, there is little data available at this point to take this approach.

Therefore, as with the ancillary services, we use the RERT costs as published by AEMO for the 12-month period prior to the Determination. ACIL Allen expresses the cost based on energy consumption, by taking the reported cost in dollar terms from AEMO for the given region and prorating the cost across all consumers in the region on a consumption basis.

Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) started on 1 July 2019 to help manage the risk of declining reliability of supply in response to the recent large amounts of investment in intermittent renewable projects coupled with recent and potential closures of thermal power stations.

If the RRO is triggered for a given quarter and region of the NEM, then retailers need to secure sufficient *qualifying contracts* to cover their share of a one-in-two-year peak demand.

The RRO is currently not triggered for 2024-25 in New South Wales, Queensland or South Australia, and hence we are not required to account for the RRO in the wholesale costs for 2024-25. However, it is worth noting that this cost component should be included as part of the wholesale cost if the RRO is triggered in future determinations.

We think that entering into a mix of firm base and cap contracts satisfies the qualifying contract definition. As part of the current WEC estimation methodology, an algorithm is run to determine the optimal hedge cover for a given distribution zone for each quarter of the given determination period.

The total optimal cover is expressed as a percentage of the P50 annual peak demand for the given quarter – which is analogous to a one-in-two-year peak demand referred to in the RRO.

Our approach to account for the triggering of the RRO in the estimated WEC is:

— If the overall level of the optimal contract cover is less than 100 per cent of the P50 annual peak demand, then increase the overall level of contract cover to 100 per cent. This will result in an increase in the WEC value since the cost of the additional contracts will be included.
— If the overall level of the optimal contract cover is equal to or greater than 100 per cent of the P50 annual peak demand then no change is required, and hence the RRO has no impact on the WEC.

AEMO Direction costs

Under the National Electricity Rules (NER) AEMO can, if necessary, take action to maintain security and reliability of the power system. AEMO can achieve this by directing a participant to undertake an action – such as directing a generator to operate even though the spot price in the NEM is less than that generator's operating cash costs. In such instances, compensation may be payable to the participant. This compensation needs to be recovered from other market participants. It is worth noting that such directions issued by AEMO are separate to ancillary services.

There are two types of system security direction:

1. Energy direction – the cost of which is recovered from customers

2. Other direction – the cost of which is recovered from customers, generators, aggregators.

Details of the recovery methodology are provided in AEMO's NEM Direction Compensation Recovery paper published in 2015[5].

In recent years, AEMO has directed selected gas fired generators in South Australia to maintain a certain level of generation to ensure the security of the power system in maintained – this is classified as an energy direction and hence its associated compensation is recovered from customers.

AEMO publishes the direction cost recovery data on a weekly basis. However, the files are prone to regular updates, as the required information to calculate the amount of compensation becomes available, and its apparent that there is a lag between the time the direction event occurs and final settlement.

AEMO also publish summaries of the costs associated with direction events in their Quarterly Energy Dynamics reports.

To arrive at the estimate of the AEMO Direction compensation costs, ACIL Allen takes the sum of the quarterly Direction costs by region for the most recent past four quarters, as presented in AEMO's latest available Quarterly Energy Dynamics Report (the latest report available at the time of undertaking our analysis for the Determination) and divided by the corresponding annual regional customer energy.

Costs associated with June 2022 NEM events

Between 12 and 23 June 2022 a series of events triggered administered pricing, spot market suspension and market interventions in the NEM consistent with the NER. As noted by AEMO in its Compensation Update published on 6 January 2023[6], these events have associated compensation and contract payments, which under the NER are to be recovered from Market Customers (mainly electricity retailers). The costs will be recovered in proportion to energy purchased in each relevant region. Hence these costs should be included in the Determination.

The AEMO Compensation Update published on 6 January 2023 summarises the costs, and groups them into the following categories:

— RERT payments
— Directions compensation
— Suspension pricing compensation
— Administered pricing compensation.

It is important to note that for this Determination, any RERT or Directions costs associated with the June 2022 events will be reported here and excluded from the usual RERT and Directions costs (to avoid double counting).

As with the 2023-24 Determination, we continue to use AEMC's published compensation costs (in $ terms) and allocate them to NEM regions in proportion to energy purchased in each relevant region (in $/MWh terms), in accordance with the National Electricity Rules.

Compensation costs that were published prior to the 2023-24 Final Determination cut-off date of 10 May 2023 were included in the 2023-24 Final Determination energy costs. Any outstanding

[5] https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2015/direction-recovery-reconciliation-file-v13.pdf

[6] https://aemo.com.au/-/media/files/electricity/nem/data/mms/2022/june-2022-nem-events-compensation-jan-6.pdf?la=en

compensation amounts published after the cut-off date will be included in the Determination for 2024-25.

2.3.4 Environmental costs

Large-scale Renewable Energy Target (LRET)

By 31 March each compliance year, the Clean Energy Regulator (CER) publishes the Renewable Power Percentage (RPP), which translates the aggregate LRET target into the number of Large-scale Generation Certificates (LGCs) that liable entities must purchase and acquit under the scheme.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the LRET scheme is derived by multiplying the RPP and the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail electricity tariffs.

Market-based approach

A market-based approach is used to determine the price of a LGC, which assumes that an efficient and prudent electricity retailer builds up LGC coverage prior to each compliance year.

This approach involves estimating the average LGC price using LGC forward prices for the two relevant calendar compliance years in the determination period. Specifically, for each calendar compliance year, the trade-weighted average of LGC forward prices since they commenced trading is calculated.

To estimate the costs to retailers of complying with the LRET for 2024-25, ACIL Allen uses the following elements:

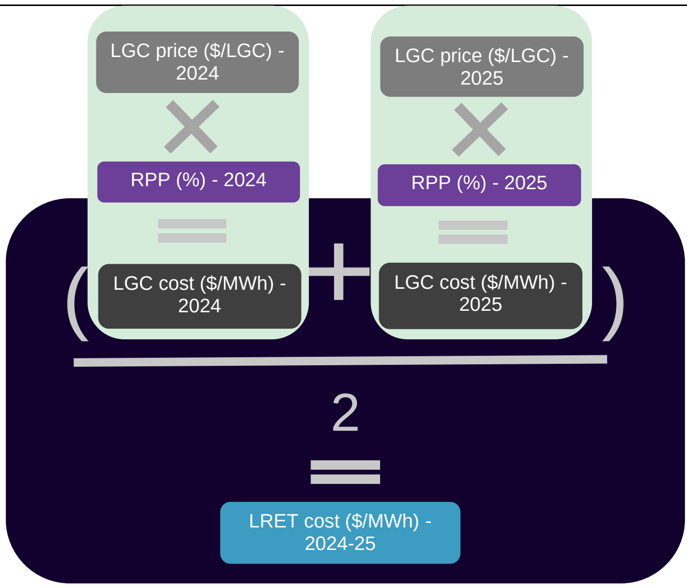
— The average of the trade-weighted average of LGC forward prices for 2024 and 2025 from brokers TraditionAsia

— the Renewable Power Percentage (RPP) for 2024, published by the CER

— the estimated Renewable Power Percentage (RPP) for 2025[7].

[7] The estimated RPP value for 2025 is estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2024 and 2025.

Figure 2.9 Steps to estimate the cost of LRET



Source: ACIL Allen

Small-scale Renewable Energy Scheme (SRES)

Similar to the LRET, by 31 March each compliance year, the CER publishes the binding Small-scale Technology Percentage (STP) for the year and non-binding STPs for the next two years.

The STP is determined ex-ante by the CER and represents the relevant year's projected supply of Small-scale Technology Certificates (STCs) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

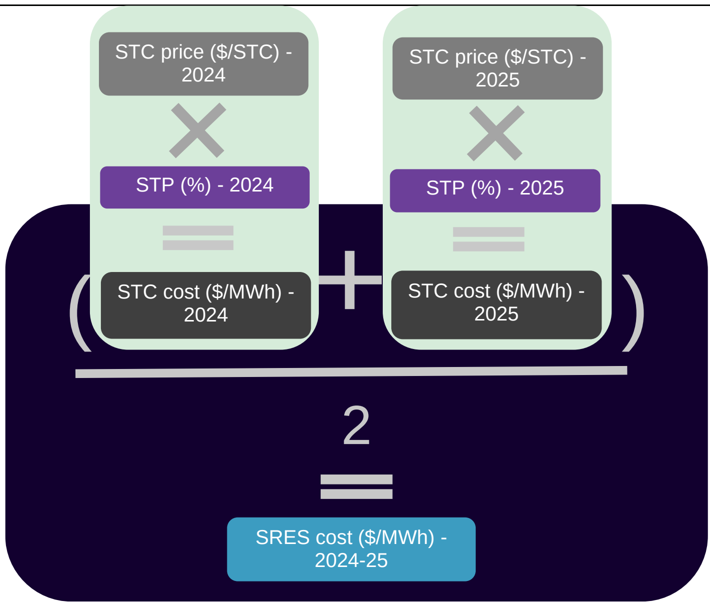
To estimate the costs to retailers of complying with the SRES, ACIL Allen uses the following elements:

— the binding Small-scale Technology Percentage (STP) for 2024 as published by the CER
— an estimate of the STP value for 2025[8]
— CER clearing house price[9] for 2024 and 2025 for Small-scale Technology Certificates (STCs) of $40/MWh.

[8] The STP value for 2025 is estimated using estimates of STC creations and liable acquisitions in 2025, taking into consideration the CER's non-binding estimate.

[9] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

Figure 2.10 Steps to estimate the cost of SRES



Source: ACIL Allen

2.3.5 Other environmental costs

New South Wales Energy Savings Scheme (ESS)

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

To estimate the cost of complying with the ESS, ACIL Allen uses the following elements:

— Energy Savings Scheme Target for 2025 and 2024 of 10 and 10.5 per cent respectively, as published by IPART

— Historical Energy Savings Certificate (ESC) market forward prices for 2024 and 2025 from brokers TFS.

New South Wales Peak Demand Reduction Scheme (PDRS)

The New South Wales Government established the Peak Demand Reduction Scheme (PDRS) in September 2021. The scheme commenced on 1 November 2022 and its primary objective is to create financial incentives to encourage peak demand reduction activities. Similar to the ESS, the PDRS is a certificate trading scheme in which retailers are required to fund peak demand reduction through the purchase of peak reduction certificates (PRCs). A PRC is equivalent to 0.1 kW of peak demand reduction capacity averaged across one hour.

To estimate the cost of complying with the PDRS, ACIL Allen uses the following elements:

— The peak demand reduction target for 2024-25 of three per cent, as published by the New South Wales and Department of Planning, Industry and Environment

— Historical PRC market forward prices for 2024 and 2025 from brokers TFS.

South Australia Retailer Energy Productivity Scheme (REPS)

The Retailer Energy Productivity Scheme (REPS) requires energy retailers with sales and customer numbers above certain thresholds (obliged retailers) to provide energy productivity activities to South Australian households and businesses to meet annual Ministerial targets. The REPS replaces the Retailer Energy Efficiency Scheme (REES), which was included up to DMO 3 inclusive.

The targets are set by the South Australian Minister of Energy and Mining, and Essential Services Commission of South Australia (ESCOSA) administer the scheme and allocates the target to each obligated retailer.

The cost of the REPS is recovered directly through retail electricity tariffs, and therefore should be considered as part of the environment cost component – but care needs to be taken that these costs are not double counted in the retail cost component.

ESCOSA in its annual report on the REPS published in August 2023 provides costs of the scheme, which we use in this determination.

2.3.6 Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

The components of the wholesale and environmental costs are expressed at the relevant regional reference node (RRN). Therefore, prices expressed at the regional reference node must be adjusted for losses in the transmission and distribution of electricity to customers – otherwise the wholesale and environmental costs are understated. The cost of network losses associated with wholesale and environmental costs is separate to network costs and are not included in network tariffs.

Distribution Loss Factors (DLF) for each distribution zone and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the wholesale energy cost estimates to incorporate losses.

The loss factors used are published by AEMO one year in advance for all NEM regions. Average transmission losses by network area are estimated by allocating each transmission connection point to a network based on their location. Average distribution losses are already summarised by network area in the AEMO publication.

As described by AEMO[10], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

*Price at load connection point = RRN Price * (MLF * DLF)*

The MLFs and DLFs used to estimate losses for the Draft Determination for 2024-25 are based on the draft 2024-25 MLFs and final 2023-24 DLFs published by AEMO.

The MLFs and DLFs used to estimate losses for the Draft Determination for 2024-25 will be based on the final 2024-25 MLFs and DLFs to be published by AEMO in early April 2024.

[10] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

Responses to submissions to Issues Paper 3

The AER forwarded to ACIL Allen a total of 19 submissions in response to its Issues Paper. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration. A summary of the review is shown below in Table 3.1.

The issues raised in the submissions cover the following broad areas:

— Use of the 95th percentile simulated WEC
— Wholesale spot simulations
— Inclusion of interval meter load data
— Estimating separate WEC for different customer types
— Contract instruments used in the hedge model
— Hedge book build up period
— Prudential costs
— Unaccounted for energy (UFE).

Table 3.1 Review of issues raised in submissions in response to Draft Determination

ID	Stakeholder	WEC	Hedge model	Environmental costs	NEM fees	Other costs	Energy losses
1	Ist Energy	Yes	Yes	Nil	Nil	Nil	Nil
2	Australian Energy Council	Yes	Yes	Nil	Nil	Nil	Nil
3	AGL	Yes	Yes	Nil	Nil	Nil	Nil
4	Alinta Energy	Yes	Yes	Nil	Nil	Nil	Nil
5	Business SA	Nil	Nil	Nil	Nil	Nil	Nil
6	Customer Consultative Group	Nil	Nil	Nil	Nil	Nil	Nil
7	Energy Consumers Australia	Nil	Nil	Nil	Nil	Nil	Nil
8	Energy Locals	Yes	Yes	Nil	Nil	Nil	Nil
9	EnergyAustralia	Yes	Yes	Nil	Nil	Nil	Nil
10	GloBird Energy	Yes	Yes	Nil	Nil	Nil	Nil
11	Hon Penny Sharpe MLC	Nil	Nil	Nil	Nil	Nil	Nil
12	Momentum Energy	Yes	Yes	Nil	Nil	Nil	Nil
13	Origin Energy (Origin)	Yes	Yes	Nil	Nil	Nil	Nil
14	Public Interest Advocacy Centre	Nil	Nil	Nil	Nil	Nil	Nil
15	Powershop	Yes	Yes	Nil	Nil	Nil	Nil
16	Red Energy and Lumo Energy	Yes	Nil	Nil	Nil	Nil	Nil
17	SA Department of Energy and Mining	No	Nil	Nil	Nil	Nil	Nil
18	SACOSS	Nil	Nil	Nil	Nil	Nil	Nil
19	Simply Energy	Yes	Nil	Nil	Nil	Nil	Nil

ID	Stakeholder	WEC	Hedge model	Environmental costs	NEM fees	Other costs	Energy losses

Note: Yes = an issue was raised that required ACIL Allen's consideration
Source: ACIL Allen analysis of AER supplied documents

3.1 Overall approach to estimate the wholesale and environmental costs

A number of stakeholders re-iterated their support for the continuation of the overall approach adopted in DMO 4 to estimate the wholesale and environmental costs for DMO 5 to maintain consistency, albeit with minor modifications, these include:

— 1st Energy
— AEC
— AGL
— Energy Consumers Australia
— Energy Locals
— EnergyAustralia
— Origin Energy
— Red Energy and Lumo Energy.

There were no submissions not in support of the overall current approach to estimating the wholesale and environmental costs.

3.2 Use of the 95th percentile simulated WEC

As with DMO 4 and DMO 5, the notable issue raised in submissions relates to adopting the 75th percentile WEC.

Most retailers and the AEC reiterated their support to revert to the previous approach of using the 95th percentile simulated WEC as the final estimate of the WEC. Most of these stakeholders point to the heightened uncertainty and increasing price environment as a reason for reverting to use the 95th percentile.

ACIL Allen has presented the rationale for adopting the 95th percentile simulated WEC in its methodology papers for DMO 2 and 3. Estimating the WEC inherently involves a degree of uncertainty. Adopting a high percentile estimate from the simulations as the final estimate of the WEC minimises the risk of underestimating the true value of the WEC – noting the DMO is a form of price cap. It also recognises that the risk inherently sits with retailers rather than consumers.

Further, adopting a higher percentile recognises the varying degree of price uncertainty between the different regions and load profiles. Whereas, adopting the 50th percentile, as an extreme example, in effect assumes the same degree of uncertainty for all regions and load profiles, which is not the case.

Finally, our analysis in Figure 2.8 of actual outcomes in Queensland relative to the past DMOs shows that due to the skewed nature of price outcomes in the NEM, the error in the WEC estimate, due to contract price variation, is likely to be greater in an environment of increasing prices, than it is in an environment of decreasing prices.

3.2.1 ACIL Allen response

The AER has requested ACIL Allen to continue to present the 75th percentile WEC for this Determination as the final estimate of the WEC. Consequently, the final estimates of the WECs presented in sections 4.2.4 and 4.6 are the 75th percentiles of the simulated WECs.

3.3 Spot price simulations

Origin on page one of its submission raise the matter of the variability in spot prices below $300/MWh across the simulations being less than the variability observed in historical outcomes, and suggest that by including variability in fuel prices, greater variability in plant availability, hydro output and delays in the commissioning of new plant across the simulations would improve the simulation accuracy and be more reflective of the uncertainty faced by retailers when managing their retail load.

3.3.1 ACIL Allen response

Unlike variability in price spikes, which are driven by stochastic influences, ACIL Allen does not expect the variability in sub-$300 prices to be as great as what has been observed historically. There are good reasons for this. There have been fundamental structural changes in the NEM over the past decade which influence the historical variability in sub-$300 price outcomes – structural changes that are hard to imagine being undone over the next 12 months, such as the commissioning of nearly 20,000 MW of wind and solar farm capacity, the closure of multiple coal plant, the change in the demand profile to be satisfied by NEM scheduled and semi scheduled generation.

The simulations are looking forward one year and therefore have a higher degree of clarity around any potential future structural changes.

Increasing the variability in plant availability beyond what is currently adopted in the spot price simulations would more likely result in an increase in price volatility (in prices about $300/MWh) more so than an increase in sub-$300/MWh price outcomes.

Although it is possible to include a high and low fuel price scenario in addition to the fuel price scenario adopted in the spot price simulations, and this would increase the variability in price outcomes below $300/MWh, it is likely to have little impact on the final WEC outcome if the high and low fuel prices are symmetrically located around the fuel prices currently adopted. Therefore, to have an impact on the WEC, the high and low fuel prices would need to be noticeably asymmetrically distributed around the current assumption, which in turn would require judgment.

Further, given the Government's recent implementation of price caps on coal and gas, it is unlikely that any large fuel price increases in the near future would not attract further intervention.

On this basis, ACIL Allen is of the view that the current methodology does not require a change.

3.4 Inclusion of interval meter demand data

A number of submissions (1st Energy, AEC, AGL, Alinta Energy, Energy Locals, EnergyAustralia, GloBird Energy, Origin, Powershop, Red Lumo, and Simply Energy) noted the importance of including the interval meter load data with the NSLP when estimating the WECs for DMO 6.

However, ACIL Allen suspects that support from retailers for the blending of the NSLP and interval meter demand data is premised on the assumption that the carve out of demand during daylight hours due to rooftop PV exports is also included in the blended profile. For example, 1st Energy on page two of its submission notes:

Solar PV is adding to the peakiness as continually increasing solar generation (in particular between 10am to 3pm) is causing load to dip and spot prices to often shift negative. This can create spot price exposure to retailers because when net load and spot prices go negative and a retailer doesn't have a commercial and industrial portfolio to offset this excess solar they're exposed to spot price outcomes. The costs of negative spot price and negative load should be incorporated into the methodology until AEMO's forecast improvement of reliability risks is evident.

And AGL on page two of its submission notes that:

The sheer volume of customers that have now installed solar PV (and typically switched to an interval meter as part of that process) means that the shape of the NSLP is materially different (and flatter) than the load profile facing retailers in reality. Accordingly, use of a load profile that does not take into account interval meter data would materially underestimate the WEC.

Alinta on page four of its submission notes:

Solar exports should be considered as part of any blended load profile. The NSLP will become increasingly unrepresentative of consumption pattern as it does not include customers with advanced meters, let alone customers with solar exports. However, it may not be possible to incorporate solar PV exports in advanced meter data for a blended profile in the time left to determine DMO6.

Energy Locals on page three of its submission suggests the DMO take into account the average market FiT when estimating the WEC.:

a retailer is now exposed to spot prices when/if they become a net generator for trading intervals. Specifically, they are paying the customer a fixed feed-in tariff (FIT) and receiving floating spot down to $-1000/MWh

EnergyAustralia on page seven of its submission states the load profile should exclude (PV) exports to the grid. Although we assume this means the PV export carve should be included when calculating the load profile.

Origin on page one of its submission notes:

We support the AER adopting a blended load profile based on a combination of net system load profile (NSLP), controlled load profile (CLP) and advanced meter data, with solar exports netted-off. This will better reflect a typical retailer's small customer load and therefore support a more accurate calculation of the cost of supplying energy to those customers.

3.4.1 ACIL Allen response

ACIL Allen has presented its consideration of this matter in section 2.3.1

The blended demand profile adopted for DMO 6 will continue to include the carve out of PV exports for those customers with rooftop PV *on the NSLP* since this cannot be disentangled from the NSLP data. However, ACIL Allen is of the view that the carve out of exports for those customers on interval meters ought to be excluded so that the interval meter demand profile in effect is the profile of consumption drawn from the grid. We take this view because the DMO scope:

1. relates to the price ceiling for electricity consumption drawn from the grid (not net consumption drawn from the grid)
2. does not have jurisdiction over rooftop PV feed in tariffs (FiTs) – retailers are free to set their respective FiTs independent of the DMO process.

If retailers were charging customers based on their consumption less their PV exports then it would seem appropriate to include the PV export carveout in the profile. But this is not what happens. Instead, retailers charge a customer the equivalent of the WEC multiplied by the customer's consumption, and pay the customer a FiT (at a very different price to the WEC) for any PV exports.

3.5 Separate WECs for residential and small business customers, and single WEC for New South Wales

The AER in its Issues Paper asked stakeholders whether separate WECs should be calculated for residential and small business customers, and whether the profiles for the three distribution networks in New South Wales be merged into a single profile.

3.5.1 Separate WECs for residential and small business customers

The majority of stakeholders (1st Energy, AGL, Alinta, Energy Locals, EnergyAustralia, Momentum) supported the continuation of a single WEC for residential and small business customers given that retailers tend to consider the combined profile when considering their hedging strategy, and that it maintains consistency in approach compared with previous DMO determinations.

GloBird Energy, Powershop, Red Lumo, and Simply Energy supported the separation of estimates for residential and small business customers.

Powershop also suggested the separation of residential customers into those with and without rooftop PV, and with and without smart meters.

3.5.2 Merging the three NSW profiles into one

Some stakeholders (1st Energy, Energy Locals, EnergyAustralia) supported the adoption of a single WEC in New South Wales given that retailers tend to consider the combined profiles of the three distribution networks when considering their hedging strategy, whilst other retailers (AGL, Powershop, Red Lumo, Simply Energy) did not support the change in methodology unless there was a compelling reason to do so.

3.5.3 ACIL Allen response

In previous determinations, ACIL Allen was not supportive of estimating separate WECs for residential and small business customers given the inability to separate the NSLP demand data in to different customer types, and the previously lower penetration of interval meters.

However, this is something that might be considered for future DMOs as more customers move onto interval meters and there is increased confidence that the interval meter load profiles are also representative of those customers remaining on the NSLP. This would also require AEMO to split the interval meter load data into solar and non-solar customers.

On balance, we are of the view that this represents a major change in methodology, and as such ought to be investigated thoroughly by the AER outside of the 'live' DMO process. Therefore, we propose not to estimate separate WECs for residential / small business / solar / non-solar customers for DMO 6.

3.6 Contract instruments used in the hedge model for South Australia

Despite the lower liquidity in South Australia, most retailers and the AEC were generally in favour of continuing with the current hedge book approach of relying on ASX Energy price and volume data, although some retailers and other stakeholders were in favour of using broker data to verify the ASX price data.

Most retailers (1st Energy, Alinta, Energy Locals, EnergyAustralia, Momentum, Red Lumo, Simply Energy) did not support the use of Victorian futures contracts with SRAs as a proxy for hedging in South Australia.

3.6.1 ACIL Allen's response

ACIL Allen is of the understanding that the use of SRAs with Victorian hedges is not widely adopted by retailers in South Australia as part of a risk reducing hedging strategy, and therefore proposes not to include this approach in the hedgebook model.

3.7 Hedge book build up period

Consistent with their responses to previous determinations, smaller retailers (Energy Locals, GloBird Energy, Powershop) tend support the use of a shorter book build period.

Energy Locals on page three of its submission suggest that a two-to-three-year hedging horizon is not reflective of the strategy adopted by small retailers.

GloBird Energy on page two of its submission states that a book build period of longer than 12-18 months is not appropriate as smaller retailers find it difficult to secure ASX Energy contracts beyond 12 months.

3.7.1 ACIL Allen response

ACIL Allen acknowledges that different retailers adopt different strategies to build up a hedge book. However, ACIL Allen remains of the view that using all available trade data from ASX Energy to estimate contract prices is appropriate.

As we have noted in previous determinations, about two thirds of the contract trade volume on ASX Energy typically occurs within the 12 months prior to the final determination date – demonstrating that a small portion of trades occur greater than 12 months prior to the determination – reflecting to some extent the approach adopted by smaller retailers.

For these reasons, we do not think it appropriate to change this aspect of the methodology.

3.8 Prudential costs

Momentum in its submission note that the increased prudential costs and margin calls coupled with higher interest rates have increased prudential costs but are of the view this is not adequately captured in the DMO.

3.8.1 ACIL Allen response

The methodology calculates prudential costs using the latest interest rates, margin parameters and volatility factors published by the ABS, ASX Energy and AEMO.

3.9 Unaccounted for energy (UFE).

1st Energy on page three of its submission suggested unaccounted for energy (UFE) costs be taken into account, given every retailer

is now billed for the loss-adjusted metered electricity that is consumed by their customers within a given region and this has a cost impost that was previously not apparent.

3.9.1 ACIL Allen response

UFE is the difference between all adjusted metered energy entering a local area, compared to all adjusted metered energy consumed within the local area. UFE typically comprises losses within the distribution area due to energy theft, estimation errors for unmetered connections, inaccurate meters, estimation errors from profiling meters, and estimation errors in the distribution loss factors (DLFs).

A recent Rule change[11] that introduced a global settlement framework for the demand side of the NEM from February 2022, means that UFE is allocated to all retailers via a global settlements process. Previously, UFE was settled by differences, with the UFE allocated to the local retailer in a distribution area.

AEMO has recently started publishing an annual UFE trends report. This report shows in chart format, historical UFE at a trading interval level for each local area. The data behind these charts is not publicly available. Typically, UFE varies with each interval but across the year can be expected to be very small percentage of total distribution losses. Based on this and limited availability of data, we have not included UFE in this determination.

Estimation of energy costs 4

4.1 Introduction

In this chapter we apply the methodology described in Chapter 2, and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the NSLPs and CLPs for 2023-24.

4.1.1 Historic demand and wholesale electricity spot price outcomes

Figure 4.1 to Figure 4.3 show the average time of day spot price for the Queensland, New South Wales, and South Australia regions of the NEM respectively, and the associated average time of day load profiles for the past 12 years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the profiles.

Annual average wholesale electricity prices in Queensland, New South Wales and South Australia in 2021-22 increased by about $100/MWh, $70/MWh and $60/MWh respectively when compared with 2020-21. This substantial increase is despite the continued uptake of rooftop PV putting downward pressure on price outcomes during daylight hours. The main reasons for the increase in prices overall are the:

- substantial increases in coal costs for the New South Wales and Queensland coal fired power stations that are exposed to the export coal market which experienced an increase in price from about USD$150/t in July 2021 to about USD $400/t in June 2022 due to the:
  - war in Ukraine and subsequent embargo of Russian trade in thermal coal
  - supply from some producers being voluntarily curtailed in late 2020 in response to the low export prices
  - a number of weather events also impacted coal supply chains
  - domestic reservation policies being invoked in Indonesia placing further pressure on supply.
- increase in coal price increased NEM spot price outcomes overnight and during the day when coal was at the margin.
- increase in gas costs across the NEM due to the strong increase in LNG netback (export) prices from around AUD$11/GJ in July 2021 to about AUD$40/GJ by May 2022, which increased NEM spot prices during the evening peak when gas was at the margin.
- Thermal power station outages, particularly in Queensland with the continued outage of Callide C Unit 4 as well as other plant outages (such as Kogan Creek in the first quarter of 2022) which contributed to an increase in price volatility across the evening peak periods.

In 2022-23:

- Export coal prices remained at about USD$400/t until January 2023 at which point, they declined to about USD$230/t.

— LNG netback prices in the first quarter of 2022-23 continued to grow to a peak of about AUD$70/GJ in October 2022, and then declined to about AUD$25/GJ.

— This resulted in wholesale electricity prices averaging around $145/MWh in Queensland and New South Wales, and about $123/MWh in South Australia.

— We observe some impacts of the Government's December 2022 intervention of capping coal and gas prices, on wholesale electricity spot prices.

In 2023-24 to date:

— Export coal prices declined further to about USD$130/t.

— LNG netback prices declined further to about AUD$15/GJ from the beginning of the 2023-24 financial year.

— This resulted in wholesale electricity prices reducing by about 45 per cent, averaging around $80/MWh and $75/MWh in Queensland and New South Waels respectively, and reducing by over 50 per cent, averaging around $57/MWh in South Australia.

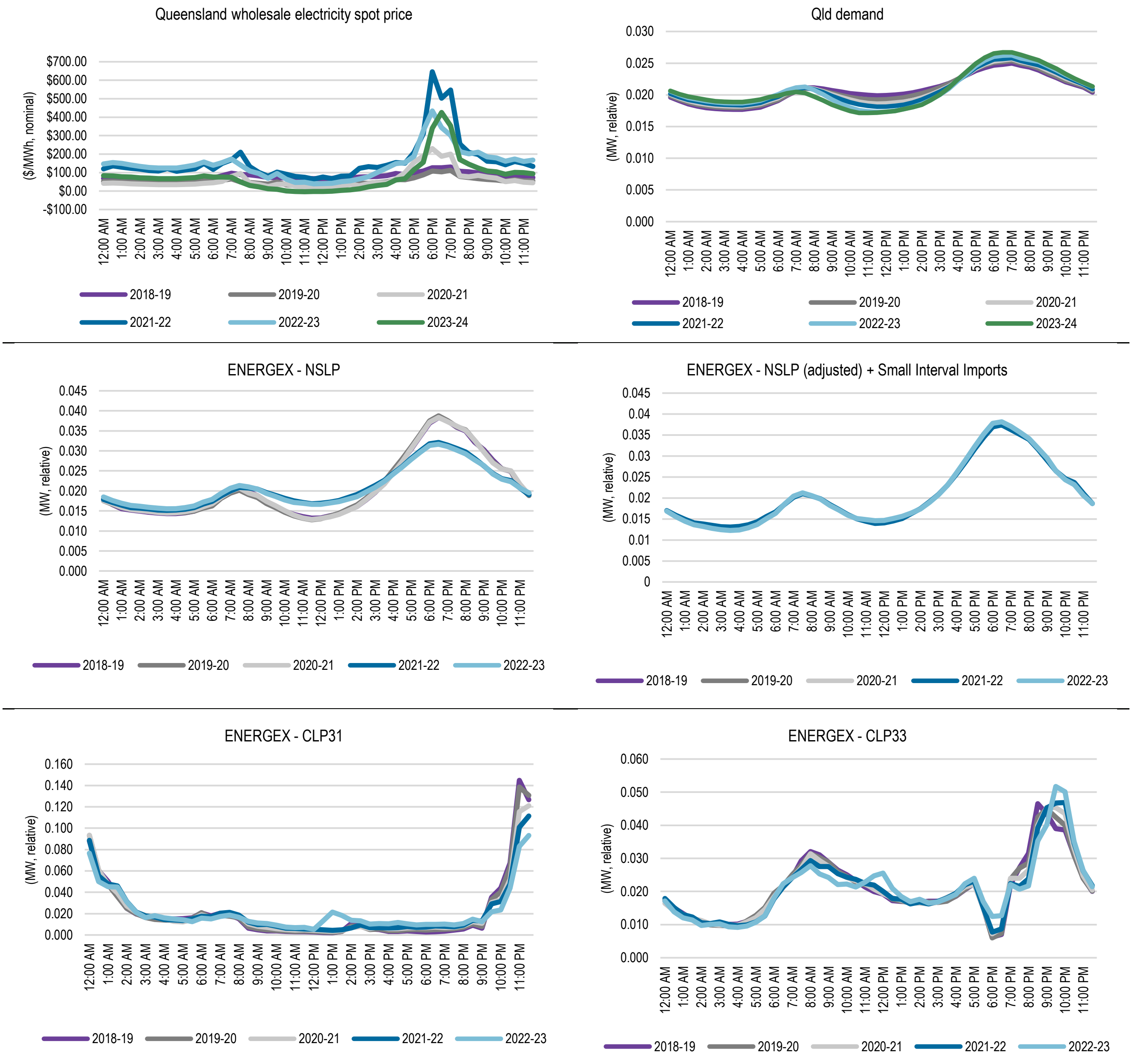
Between 2011-12 and 2019-20, the Queensland, and particularly the South Australian, NSLP load profiles, and to some degree, the New South Wales NSLPs, experienced a carving out of load during daylight hours with the increased penetration of rooftop solar PV. This resulted in the load profile becoming peakier over time and consequently, the demand weighted spot prices[12] (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP). This is particularly the case in South Australia in 2021-22 and 2022-23 (to date) – the increase in solar output has greatly reduced prices during daylight hours which will increase the hedging costs for that region's NSLP.

However, over the past few years the rate of carve out of the NSLPs has slowed and this is most likely due to new rooftop solar PV installations being paired with the installation of interval meters – removing those consumers from the NSLP. For this reason, data has been obtained for residential and small business customers on interval meters. It can be seen that when combining the NSLP and interval meter data, the trend in carve out of demand during daylight hours has slowed – reflecting the separation of the PV exports from the profile since October 2021.

Finally, we note the change in shape of the Endeavour CLP over the past two years – which now resembles the shape of the Ausgrid and Essential CLPs rather than that of the Endeavour NSLP. This will have implications for its WEC estimate for this determination as we would expect it to now have a WEC closely aligned to the Ausgrid and Essential CLPs, whereas previously its WEC was closely aligned to the Endeavor NSLP.

[12] The demand weighted price is in effect the unhedged wholesale energy cost that the retailers pay AEMO for the NSLP.

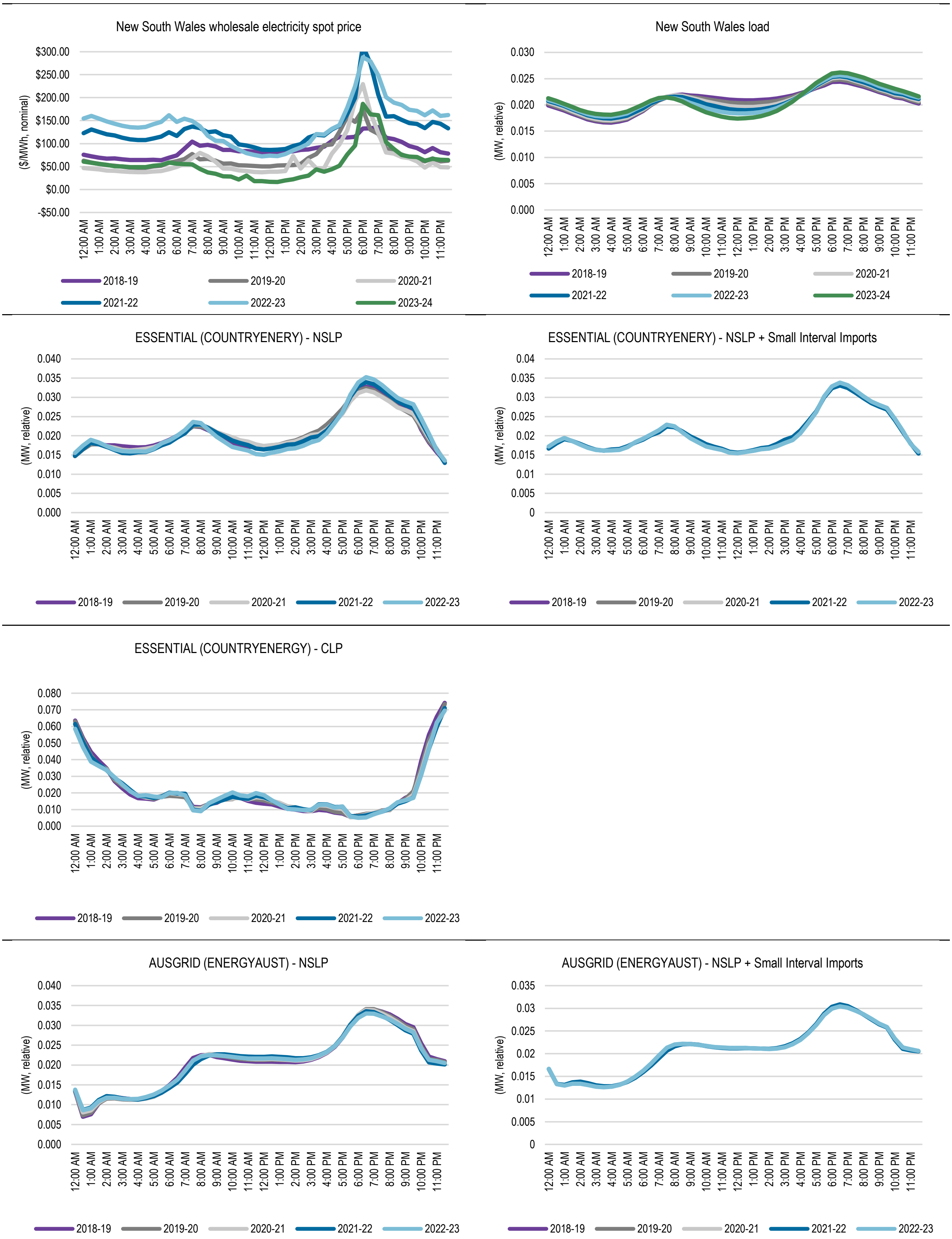
Figure 4.1 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2018-19 to 2022-23

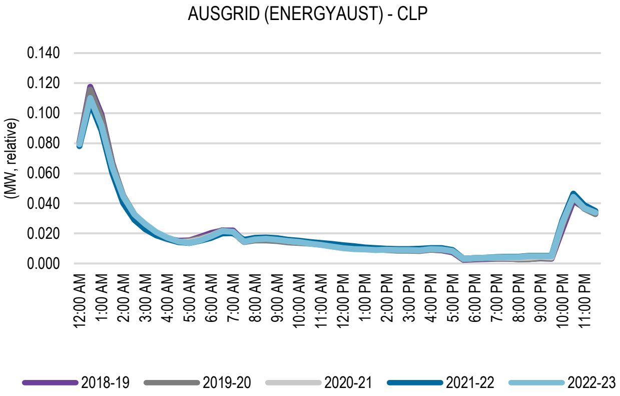


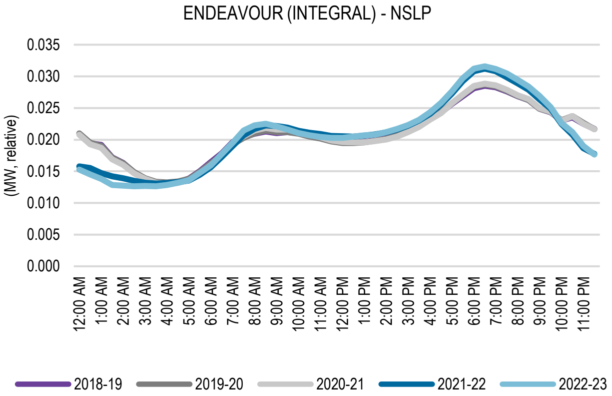
Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of the load profile, not its absolute size, which determines its wholesale energy cost. 2023-24 price and regional demand series includes data up to February 2024. Insufficient NSLP/CLP/interval meter load data available for 2023-24 and hence excluded. The stand-alone Energex NSLP has not been adjusted by ACIL Allen in this figure, but the blended NSLP and interval meter load profile includes the ACIL Allen adjustment.

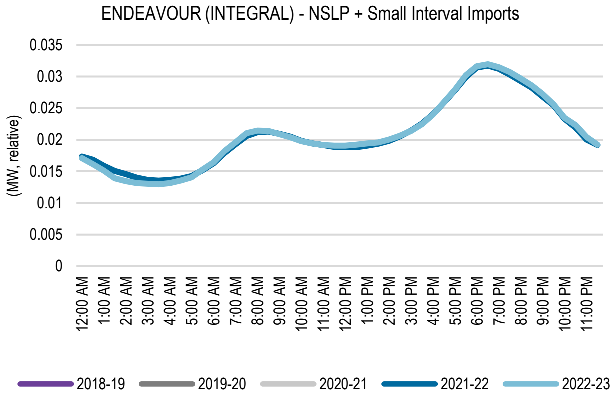
Source: ACIL Allen analysis of AEMO data

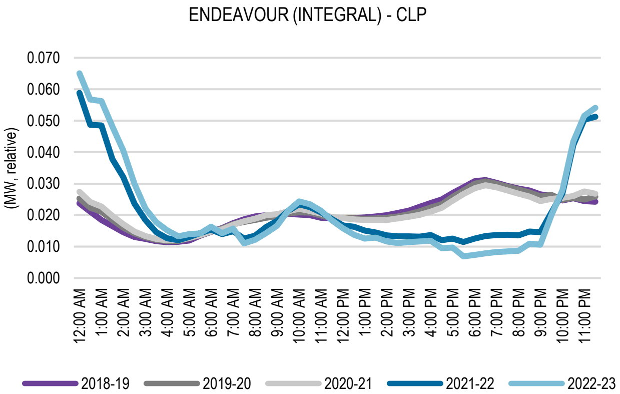
Figure 4.2 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – New South Wales – 2018-19 to 2022-23







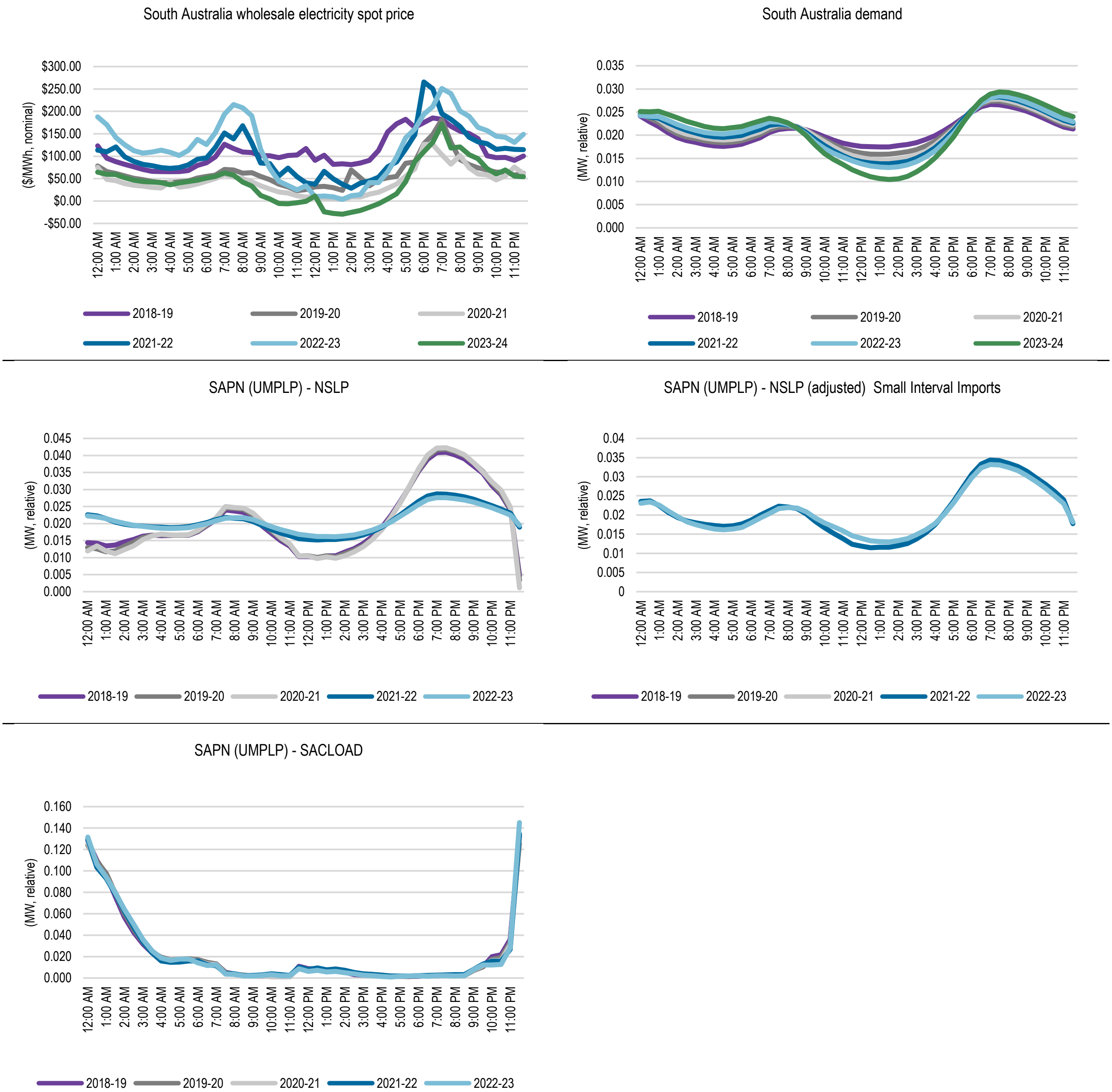




Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of the load profile, not its absolute size, which determines its wholesale energy cost. 2023-24 price and regional demand series includes data up to February 2024. Insufficient NSLP/CLP/interval meter load data available for 2023-24 and hence excluded.

Source: ACIL Allen analysis of AEMO data

Figure 4.3 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – South Australia – 2011-12 to 2022-23



Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of the load profile, not its absolute size, which determines its wholesale energy cost. 2023-24 price and regional demand series includes data up to February 2024. Insufficient NSLP/CLP/interval meter load data available for 2023-24 and hence excluded. The stand-alone Energex NSLP has not been adjusted by ACIL Allen in this figure, but the blended NSLP and interval meter load profile includes the ACIL Allen adjustment

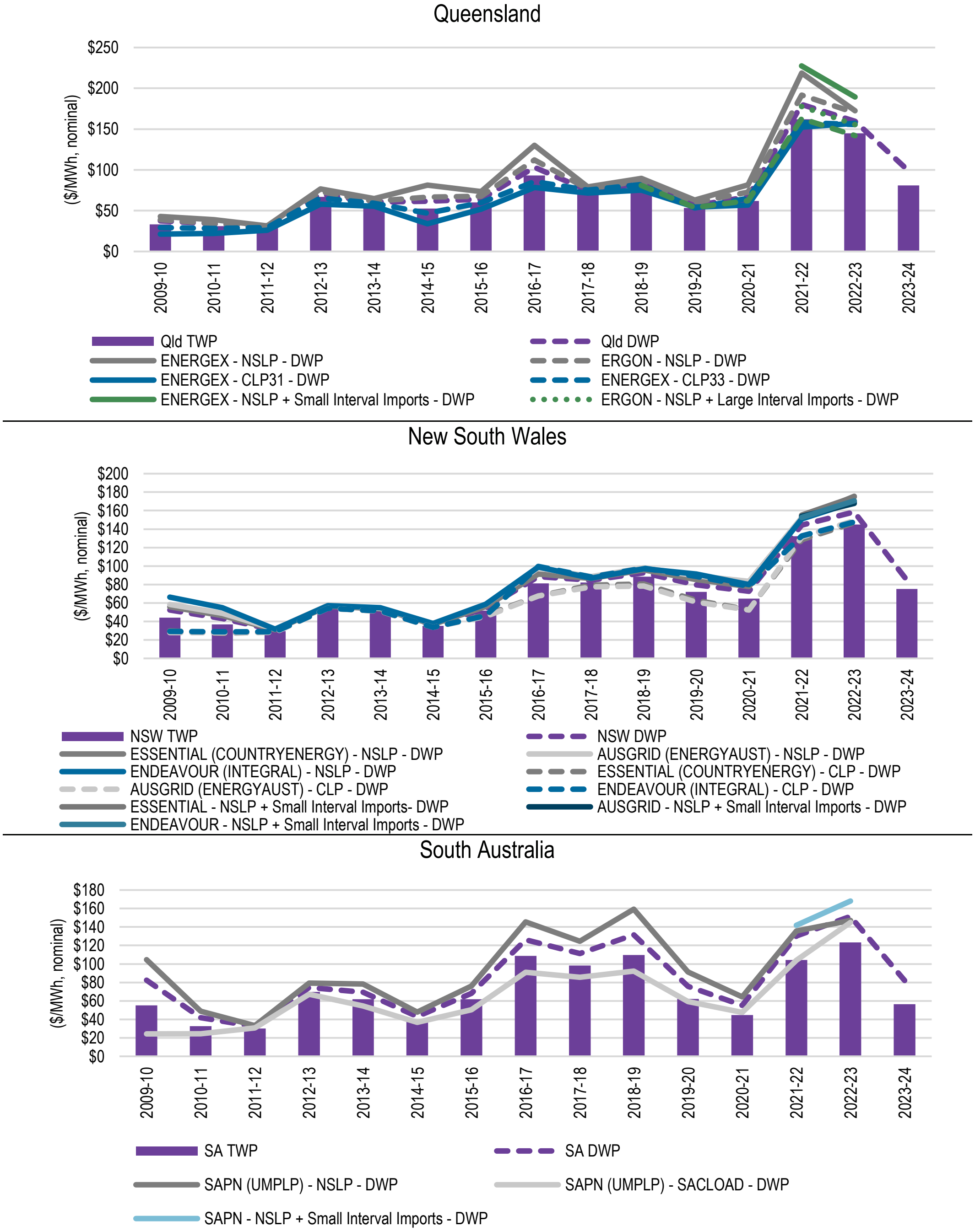
Source: ACIL Allen analysis of AEMO data

The graphs in Figure 4.4 show the actual annual DWP for each of the profiles compared with the regional TWP over the past 12 years. The DWP for the NSLPs are at about a 20, 16 and 40 per cent premium to the TWP on average over the past five years in Queensland, New South Wales, and South Australia respectively. The combined load profiles of the NSLP and residential small business customers on interval meters are at a slightly higher premium to the NSLPs – reflecting the higher penetration of rooftop PV for customers on interval meters, which is offset largely by excluding the rooftop PV export carve out.

As expected, the DWPs for the CLPs are below the DWP for the NSLPs in each year. Although the rank order in prices by profile within each region has been consistent in each year, the dollar value differences between the prices has varied from one year to the next. For example, in 2011-12, the flat half-hourly price profile across all three regions resulted in the profiles having relatively similar wholesale spot prices (within their respective region). Conversely, in 2016-17, the increased price volatility across the afternoon period resulted in the NSLP DWPs diverging away from the CLP DWPs.

It is also worth noting that it has only been for four or five of the past 12 years that the CLPs have noticeably lower DWPs when compared with the NSLPs. ACIL Allen raises this point as it is often noted that the WEC for the control loads produced by our methodology are no longer substantially lower than those of the NSLPs. For example, the change in shape of the Endeavour CLP over the past five or so years has resulted in it having a DWP about equal to the DWP of the corresponding Endeavour NSLP.

Figure 4.4 Actual annual average demand weighted price ($/MWh, nominal) by profile and regional time weighted average price ($/MWh, nominal) – 2009-10 to 2023-24



Note: Values reported are spot (or uncontracted) prices. 2023-24 price series includes data up to February 2024. Insufficient NSLP/CLP/Interval meter data available for 2023-24.

Source: ACIL Allen analysis of AEMO data

The volatility of spot prices (timing and incidence) provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) used in the methodology does not change from one year to the next. However, the movement in contract price is the key contributor to movement in the estimated wholesale energy costs of the different profiles year on year, as is shown in Figure 4.5.

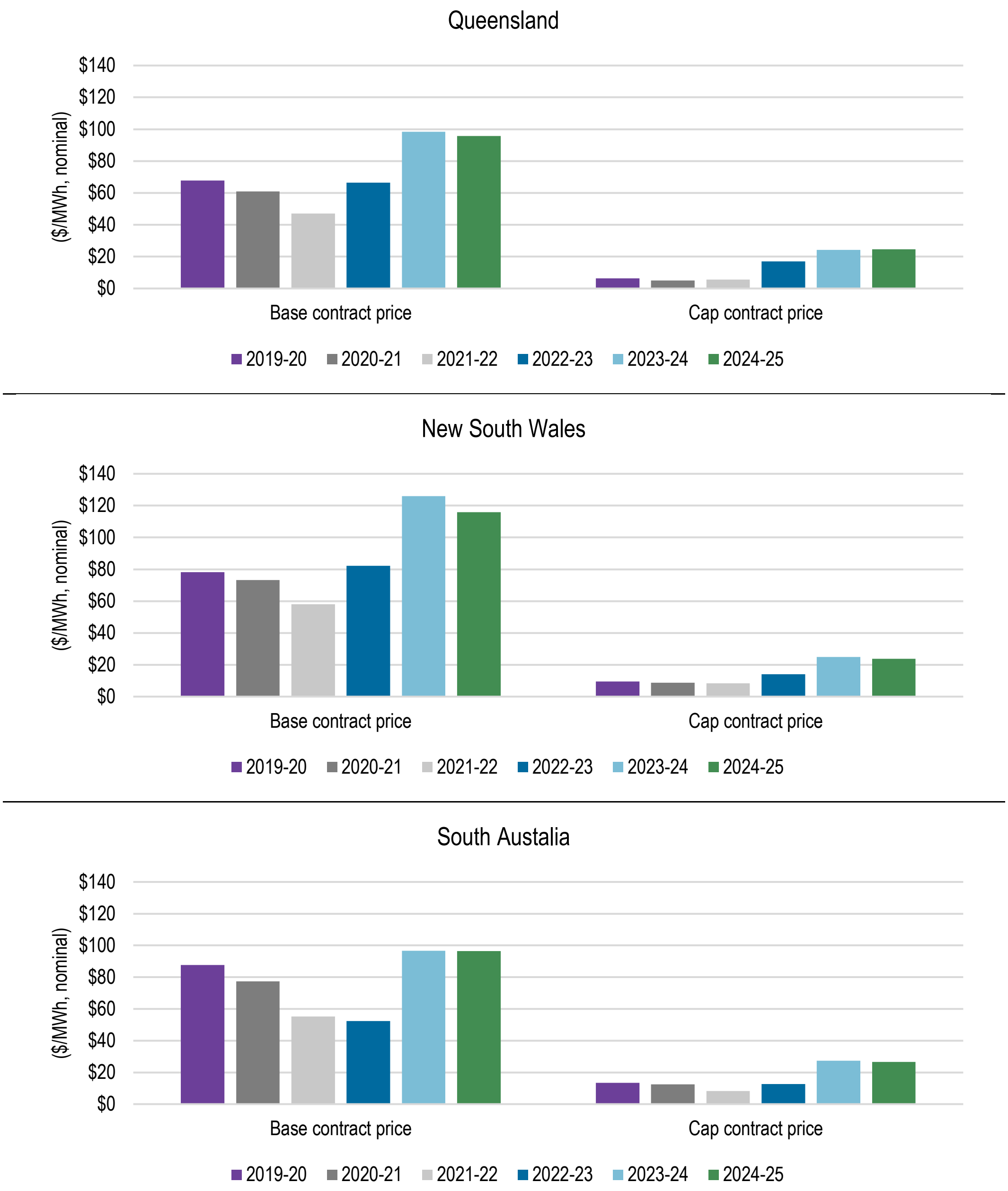
Compared with the 2022-23:

- Futures base contract prices for 2024-25, compared with 2023-24, on an annualised and trade weighted basis to date, have:
  - decreased by about $2.70/MWh for Queensland
  - decreased by about $10.00/MWh for New South Wales
  - decreased by about $0.40/MWh for South Australia.
- Cap contract prices for 2024-25, compared with 2023-24, and on an annualised and trade weighted basis to date, have:
  - increased by about $0.40/MWh for Queensland
  - decreased by about $1.20/MWh for New South Wales
  - decreased by about $0.80/MWh for South Australia.

In Queensland, the base prices have decreased and the cap prices have increased slightly. A decrease in base prices (which take into account price volatility as well as underlying price outcomes) and an increase in cap prices suggests the market is expecting slight growth in price volatility in 2024-25 during the evening peaks, offset by an increase in carve out (reduction) of daytime prices due to the continued uptake of rooftop PV and commissioning of further utility scale solar projects (which lowers prices during daylight hours).

The cost of hedging the NSLP and small interval meter load will be further exacerbated by the expected continued uptake of rooftop PV carving out the system demand during daylight hours, coupled with the commissioning of over 4,000 MW of utility scale solar. These two factors result in very low spot price outcomes during daylight hours - much less than the base contact price, meaning that the retailer will need to pay its contract counterparty for the difference between the base contract price and the very low spot price when it is over hedged.

Figure 4.5 Base, and Cap trade weighted average contract prices ($/MWh, nominal) – 2019-20 to 2024-25



Source: ACIL Allen analysis of ASX Energy Data

4.2 Estimation of the Wholesale Energy Cost

4.2.1 Estimating contract prices

Contract prices for the 2024-25 year were estimated using the trade-weighted average of ASX Energy settlement prices of individual trades of contracts and exercised base options (including the trade weighted average premium for exercised and expired base options) since the contract was listed up until 23 February 2024. The inclusion of exercised options' strike prices and option premiums in this determination is a refinement of the methodology and reflects the increasing use of options in the futures market over the past 12-24 months. To date, exercised base options contribute about 15-17 per cent of the traded volume of base 2024-25 contracts.

Table 4.1 to Table 4.3 show the estimated quarterly base and cap contract prices for 2024-25.

Table 4.1 Estimated contract prices ($/MWh, nominal) - Queensland

	Q3	Q4	Q1	Q2
2023-24				
Base	$102.68	$90.29	$115.32	$85.40
Cap	$20.02	$22.05	$37.20	$17.88
2024-25				
Base	$96.76	$87.63	$110.64	$88.05
Cap	$19.23	$20.56	$39.07	$19.95
Percentage change from 2023-24 to 2024-25				
Base	-6%	-3%	-4%	3%
Cap	-4%	-7%	5%	12%

Source: ACIL Allen analysis using ASX Energy data

Table 4.2 Estimated contract prices ($/MWh, nominal) – New South Wales

	Q3	Q4	Q1	Q2
2023-24				
Base	$147.30	$107.90	$124.23	$124.23
Cap	$24.36	$22.51	$31.39	$21.80
2024-25				
Base	$129.44	$99.54	$116.41	$118.19
Cap	$21.59	$18.01	$33.49	$22.22
Percentage change from 2023-24 to 2024-25				
Base	-12%	-8%	-6%	-5%
Cap	-11%	-20%	7%	2%

Source: ACIL Allen analysis using ASX Energy data

Table 4.3 Estimated contract prices ($/MWh, nominal) – South Australia

	Q3	Q4	Q1	Q2
2023-24				
Base	$102.52	$64.32	$109.56	$110.82
Cap	$14.81	$13.98	$65.19	$16.15
2024-25				
Base	$103.09	$69.58	$108.98	$104.09
Cap	$20.63	$16.56	$45.63	$23.93
Percentage change from 2023-24 to 2024-25				
Base	1%	8%	-1%	-6%
Cap	39%	18%	-30%	48%

Source: ACIL Allen analysis using ASX Energy data

The following charts show daily settlement prices and trade volumes for 2024-25 ASX Energy quarterly base futures, peak futures and cap contracts up to 23 February 2024. It can be seen that the trading of these contracts tends to commence from mid to late 2021. That said, the volume of trades prior to 2022 is minimal, representing less than 25 percent of all trades to date (and for some products less than 10 per cent).

There is little or no trade in peak contracts which is not surprising given the carve out of demand during daylight hours. The traditional definition of the peak period (7am to 10pm weekdays) appears to be no longer relevant to market participants when considering managing spot price risk. Hence peak contracts are excluded from the analysis and are assumed not to contribute to the hedge portfolio, as per DMO 4 and 5.

The announcement of the Government intervention in the form of coal and gas price caps has coincided with a decline in futures prices of between $50 and $100/MWh (depending on the quarterly product). However, given a reasonable portion of trades (to date) occurred prior to the announcement of the intervention in December 2022, the trade weighted average futures price has tended to stabilise to levels similar to those of the 2023-24 determination, rather than decrease since the announcement.

The relative stability of the daily settled contract prices over the past 12 months (compared with the period prior to the Government intervention) reflects the relative stability in coal and gas prices over the same period of time. That is, coincidentally or otherwise, coal and gas prices have remained at levels similar to the government price caps since the commencement of the intervention, and this has flowed through to daily settled contract prices.

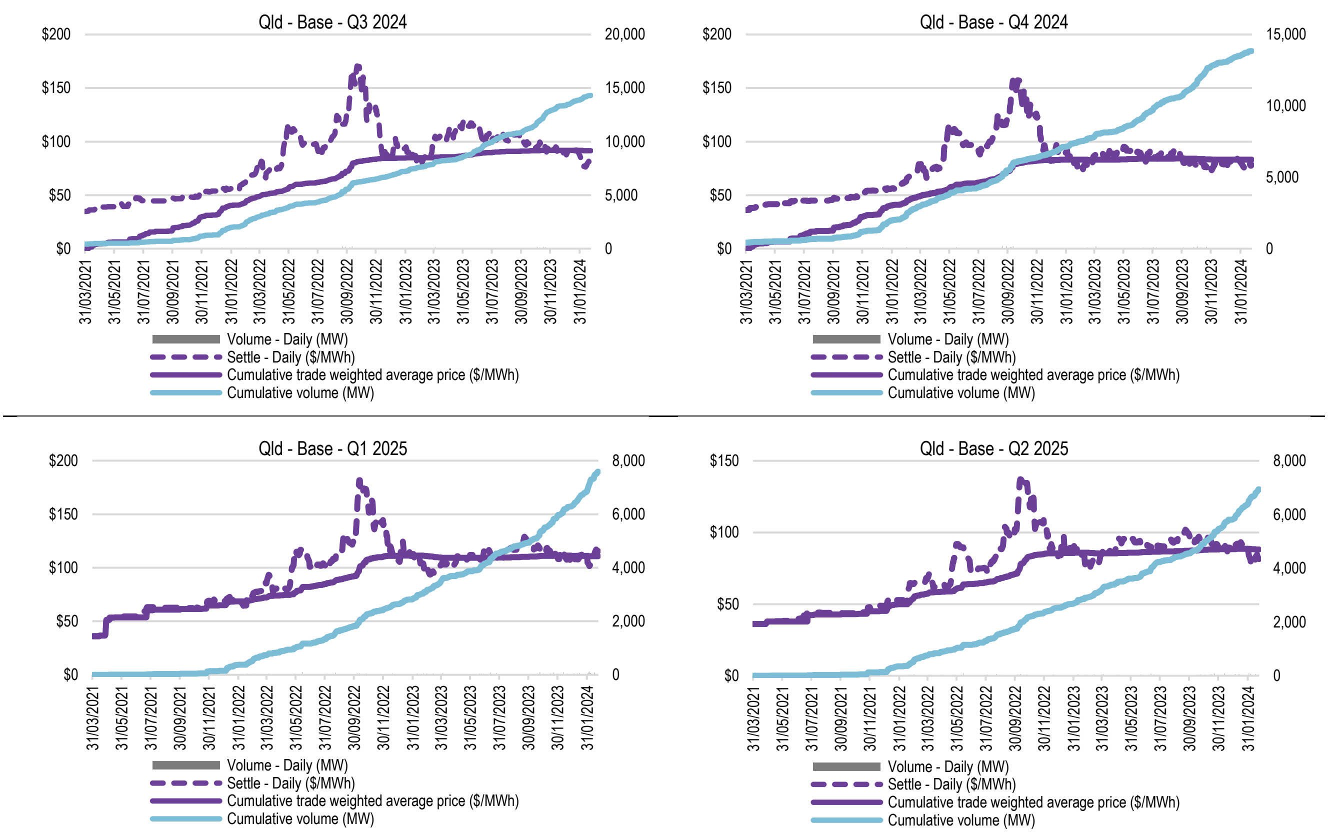
That said, although daily settled contract prices declined substantially around December 2022, they have not declined to the lower levels observed in 2021 and the first half of 2022. This could be for several reasons, including:

— current coal and gas prices are higher than what they were in 2021 and first half of 2022 (but lower than the second half of 2022)

— the market has been expecting further delays in the return to service of Callide C or further outages of other coal fired power stations

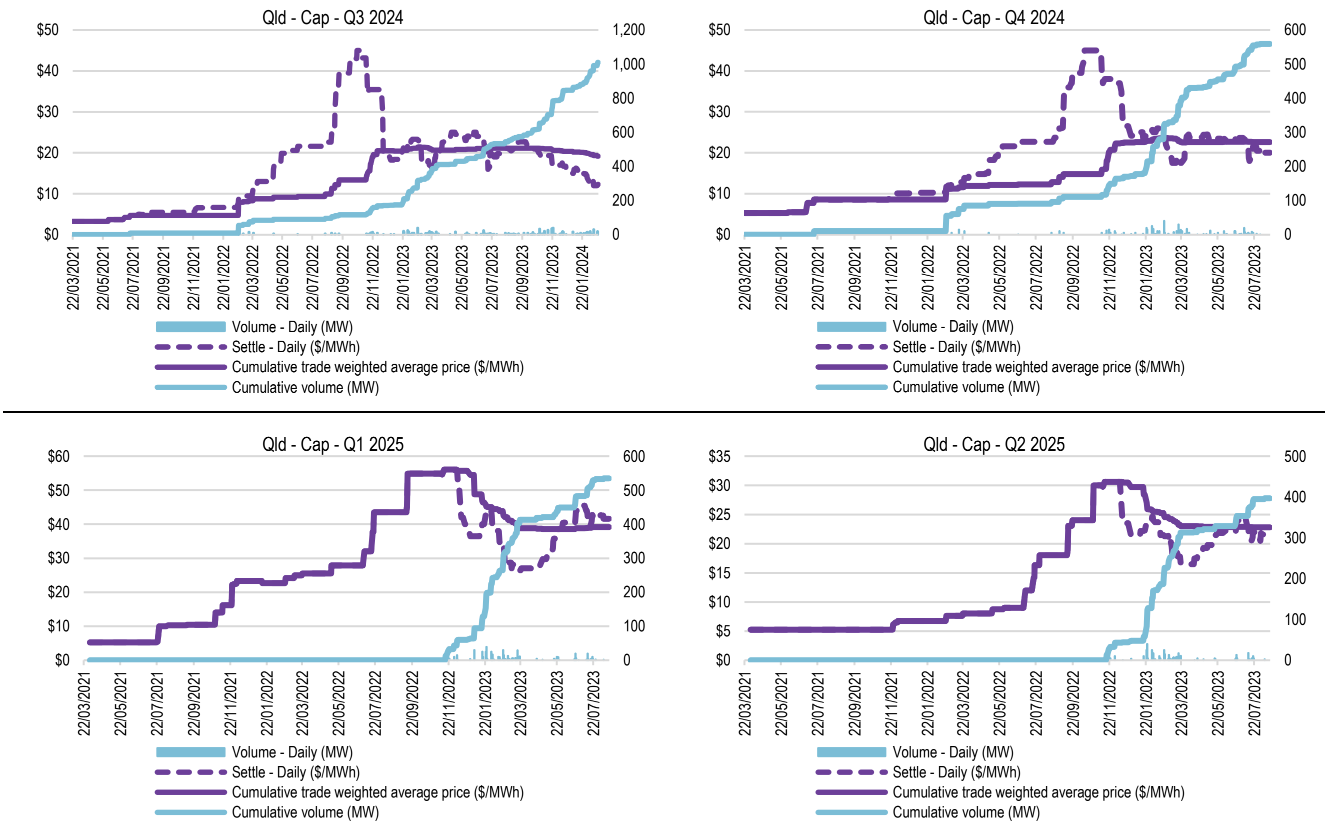
— the market was expecting a return to El Nino in 2024-25 and its associated impact on extreme weather driven demand outcomes.

Figure 4.6 Time series of trade volume and price – ASX Energy base futures - Queensland



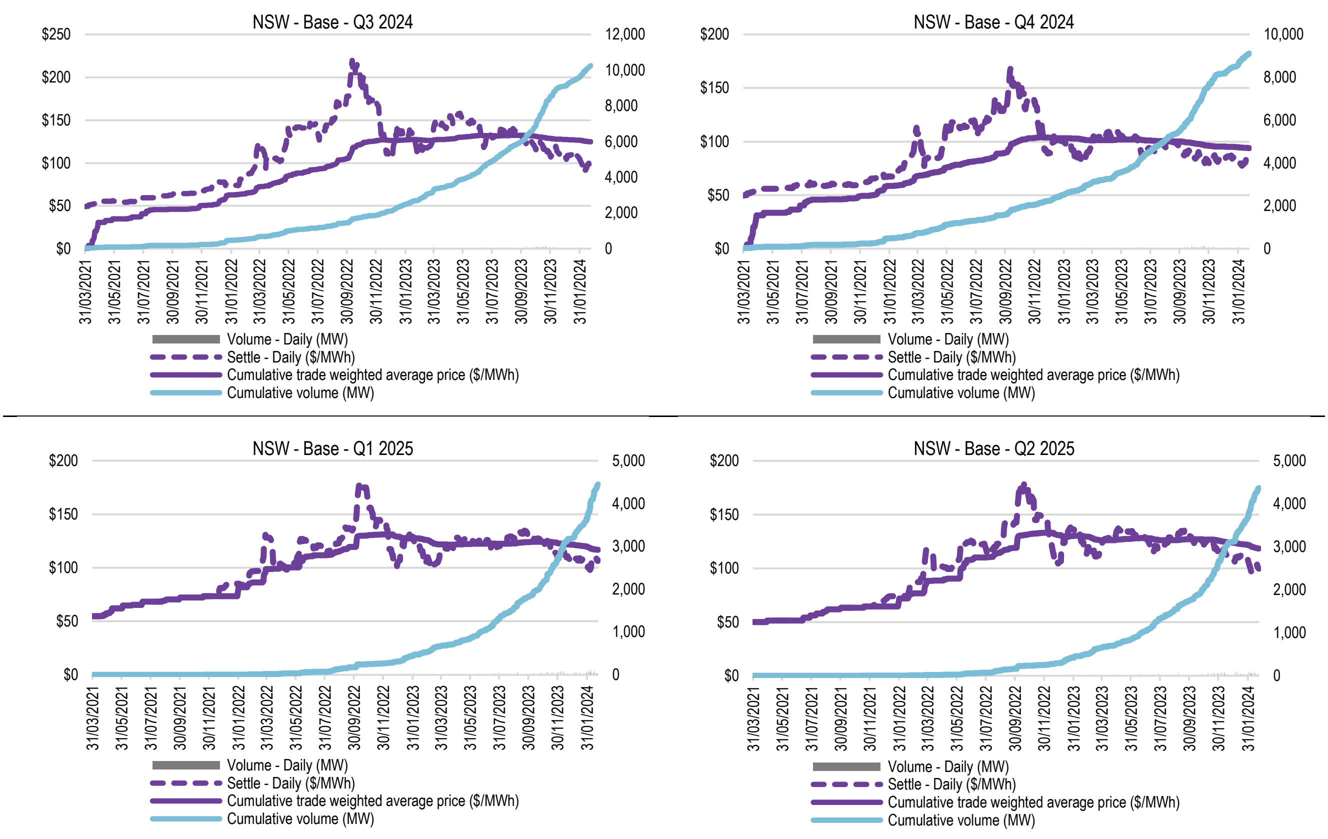
Source: ACIL Allen analysis using ASX Energy data

Figure 4.7 Time series of trade volume and price – ASX Energy $300 cap futures - Queensland



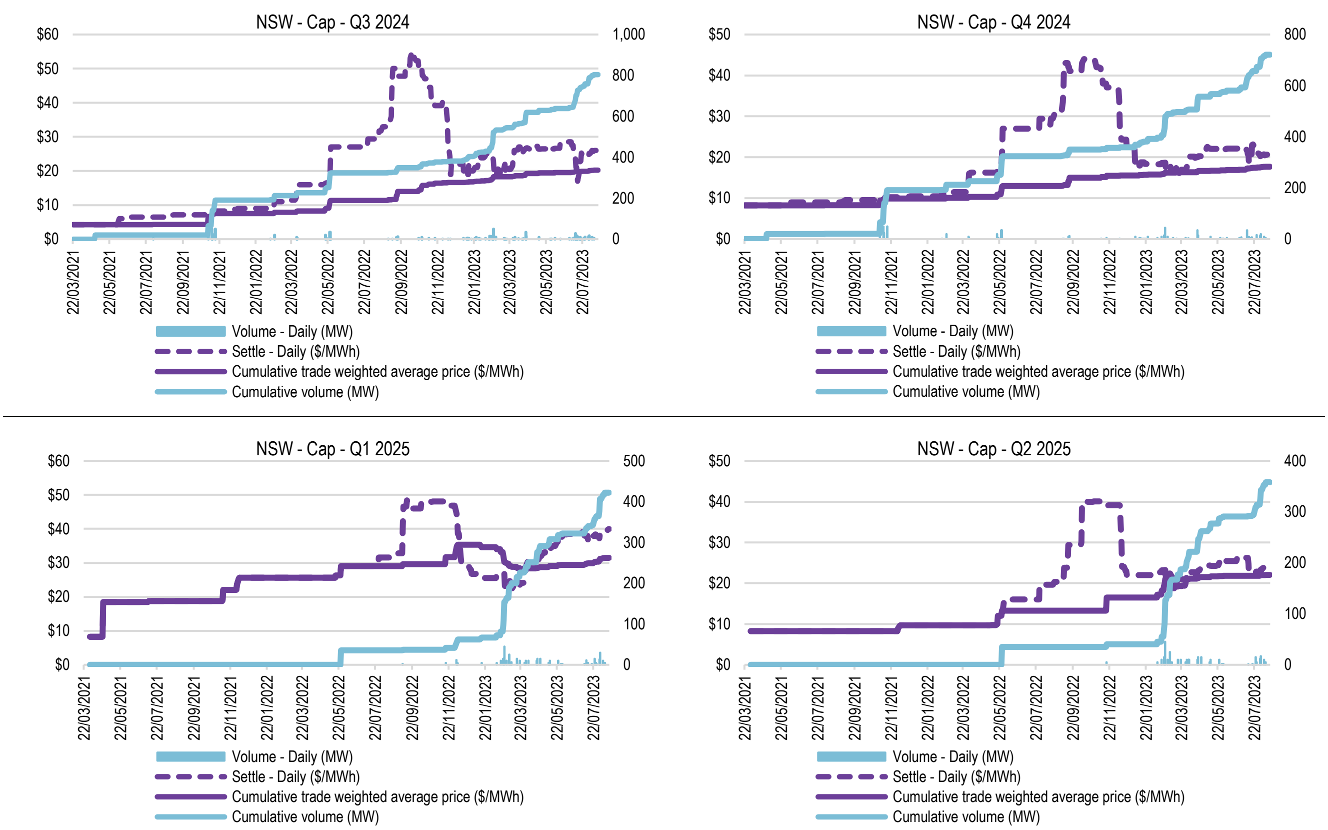
Source: ACIL Allen analysis using ASX Energy data

Figure 4.8 Time series of trade volume and price – ASX Energy base futures – New South Wales



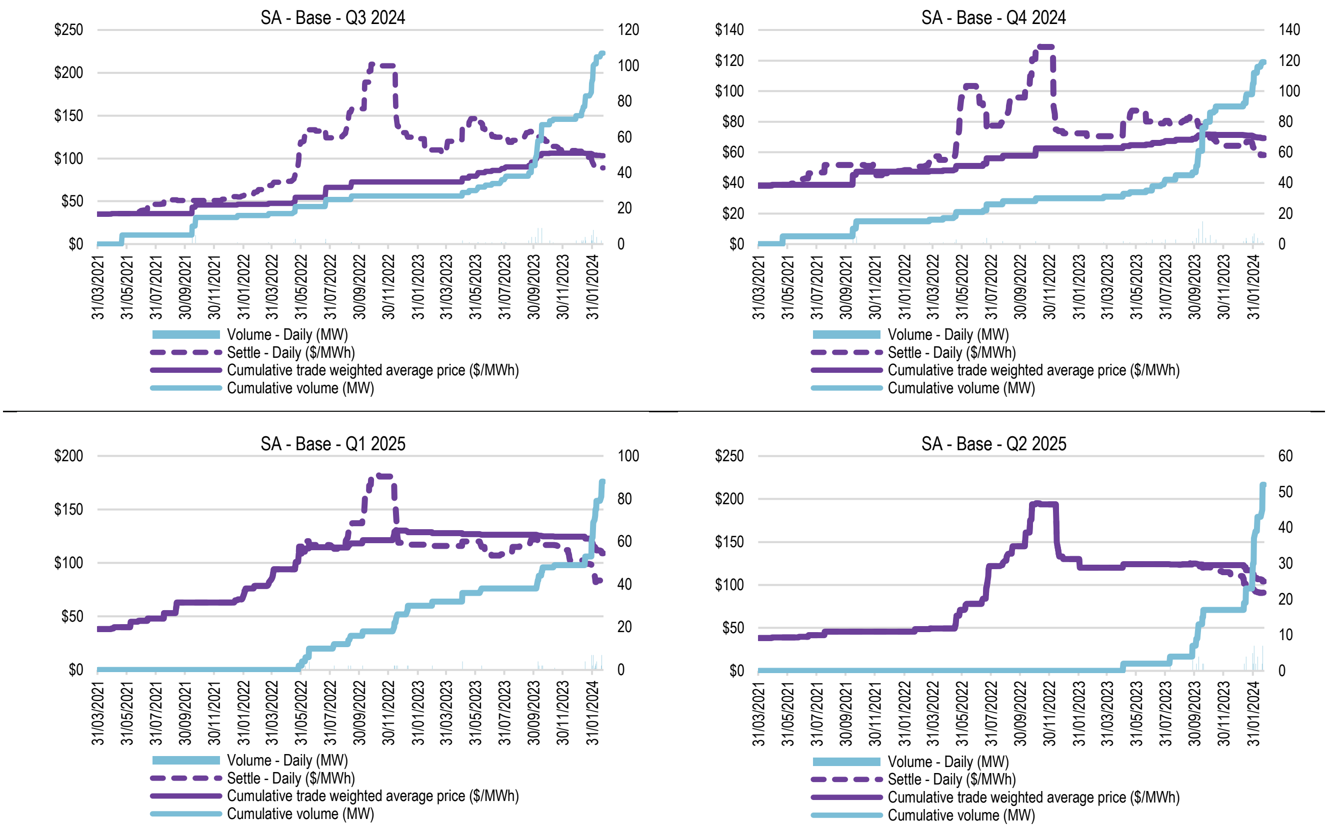
Source: ACIL Allen analysis using ASX Energy data

Figure 4.9 Time series of trade volume and price – ASX Energy $300 cap futures – New South Wales



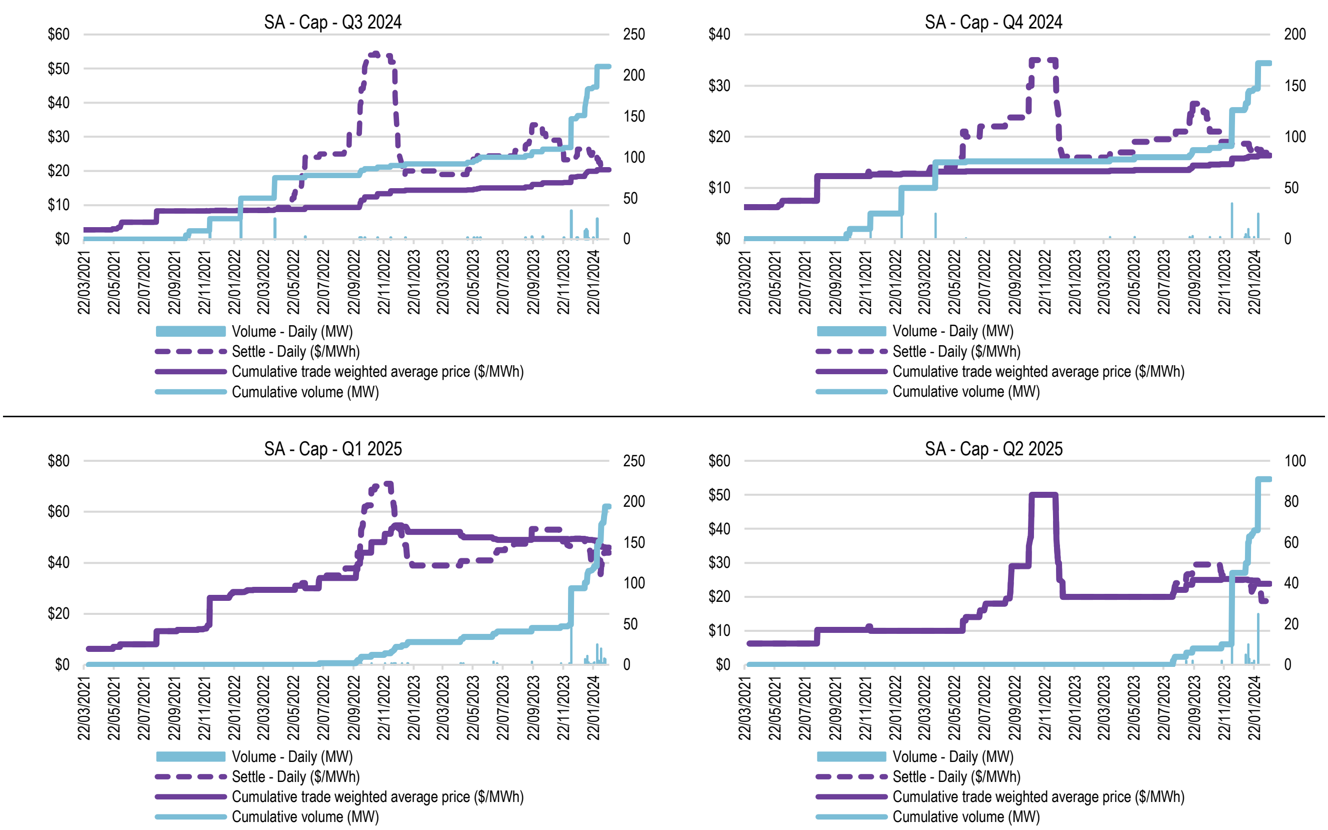
Source: ACIL Allen analysis using ASX Energy data

Figure 4.10 Time series of trade volume and price – ASX Energy base futures – South Australia



Source: ACIL Allen analysis using ASX Energy data

Figure 4.11 Time series of trade volume and price – ASX Energy $300 cap futures – South Australia



Source: ACIL Allen analysis using ASX Energy data

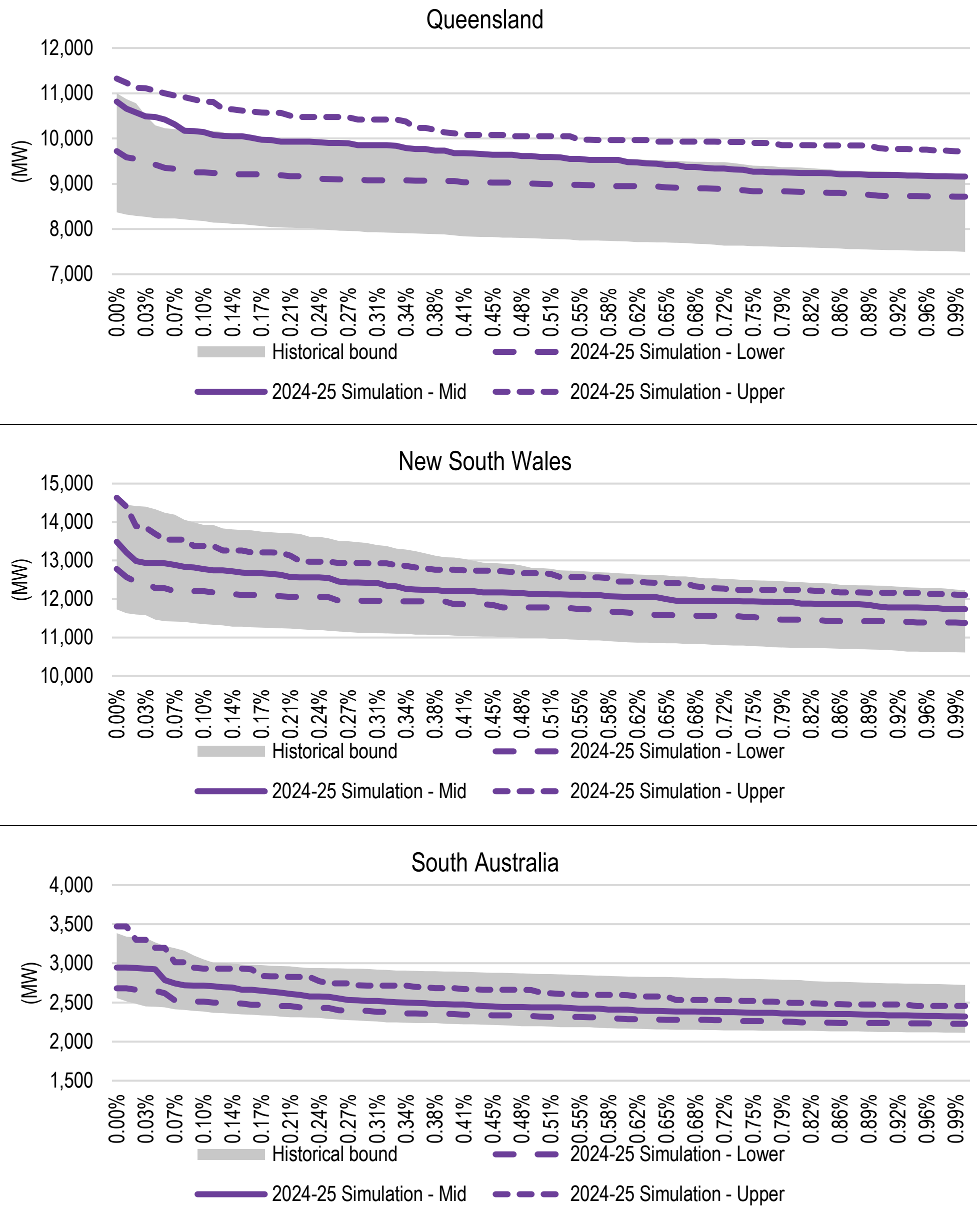
4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for the 583 simulations (53 demand and 11 outage sets).

Figure 4.12 shows the range of the upper one percent segment of the demand duration curves for the 51 simulated Queensland, New South Wales and South Australia system demand sets resulting from the methodology for 2024-25, along with the range in historical demands since 2011-12. The simulated demand curves in the charts represent the upper, lower, and middle of the range of demand duration curves across all 53 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2024-25 have a variation similar to that observed over the past five years - that is, the variation between the simulated demand sets does not just occur at the single peak annual demand but across a reasonable portion of the demands within the given simulation. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

We do not expect the simulated demand sets to line up perfectly with the historical demand sets, in terms of their absolute location. For example, the simulated demand sets for 2024-25 are generally higher than the pre-2016-17 observed demand outcomes in Queensland due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone. Further, the demand forecast for 2024-25 from AEMO's ESOO/ISP includes some growth due to the commencement of electrification in some sectors of the economy. What is important, is that the range in simulated outcomes reflects the range experienced in the past, indicating that the methodology is accounting for an appropriate degree of uncertainty.

Figure 4.12 Comparison of upper one per cent of hourly regional system loads of 2024-25 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 4.13 shows the range of the simulated NSLP and interval meter imports envelope recent actual outcomes. This variation results in the annual load factor[13] of the 2024-25 simulated demand sets ranging between:

— 25 per cent and 32 per cent compared with a range of 29 per cent to 31 per cent for the actual Energex NSLP and small customer interval meter demands (as shown in Figure 4.14**)**

— 35 per cent and 39 per cent compared with a range of 38 per cent to 45 per cent for the actual Essential NSLP and small customer interval meter demands

[13] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

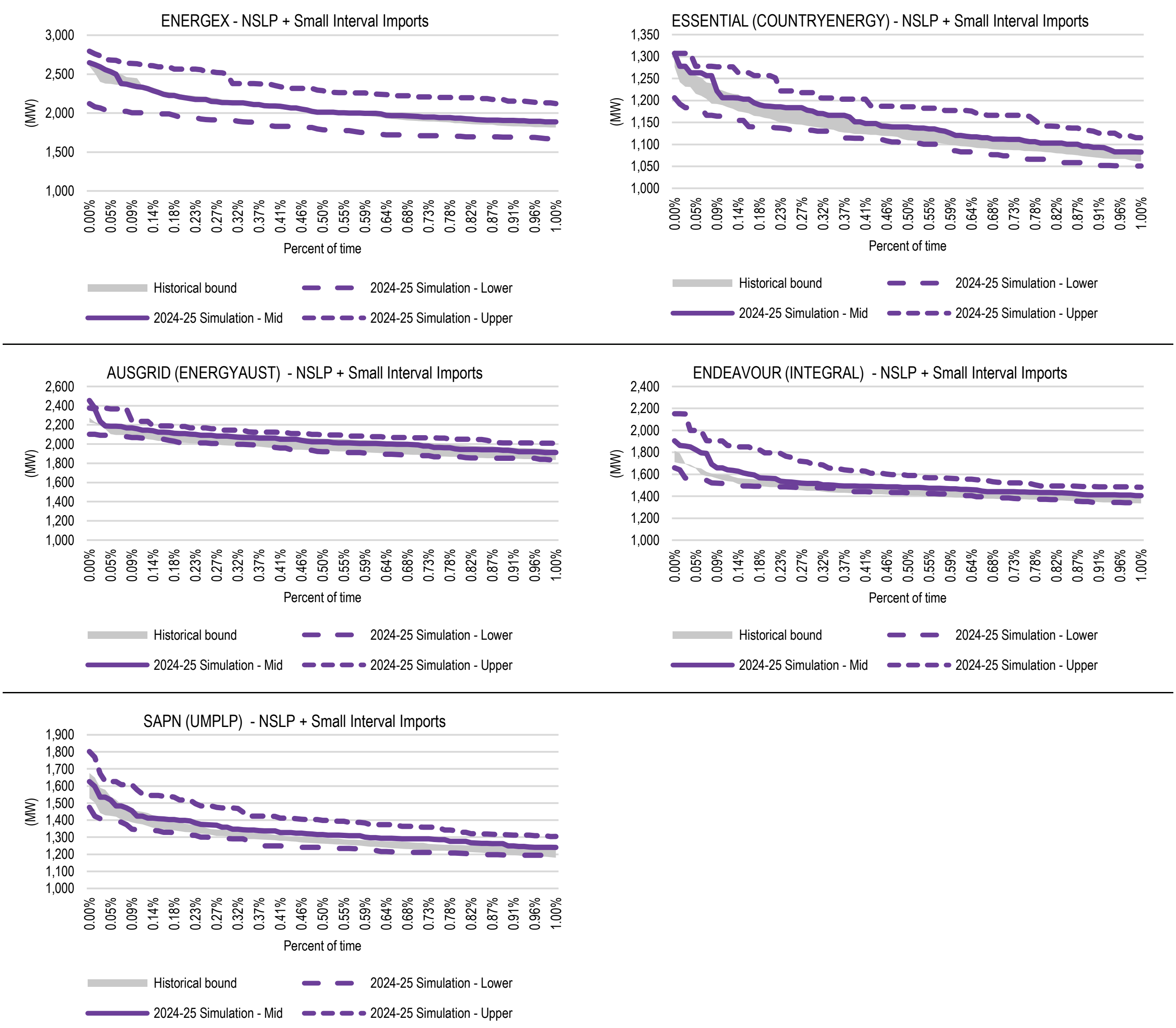
— 34 per cent and 40 per cent compared with a range of 38 per cent to 42 per cent for the actual Ausgrid NSLP and small customer interval meter demands

— 26 per cent and 34 per cent compared with a range of 32 per cent to 37 per cent for the actual Endeavour NSLP and small customer interval meter demands

— 27 per cent and 35 per cent compared with a range of 30 per cent to 33 per cent for the actual SAPN NSLP and small customer interval meter demands.

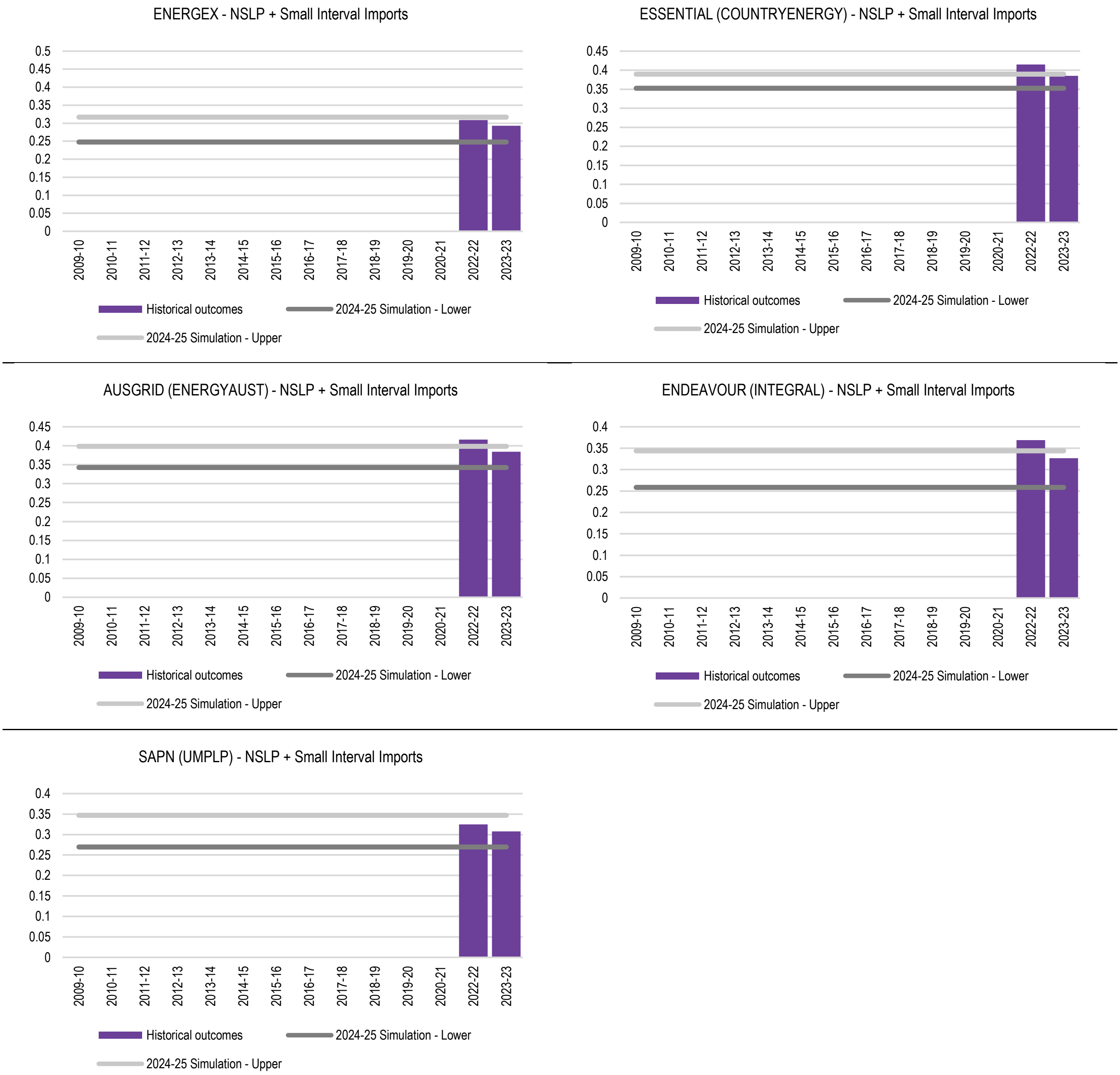
All other things being equal, an increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging costs will increase. And the converse also holds.

Figure 4.13 Comparison of upper one per cent of hourly NSLP and small interval meter loads of 2024-25 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 4.14 Comparison of load factor of 2024-25 simulated hourly demand sets with historical outcomes – NSLP and small interval meter load

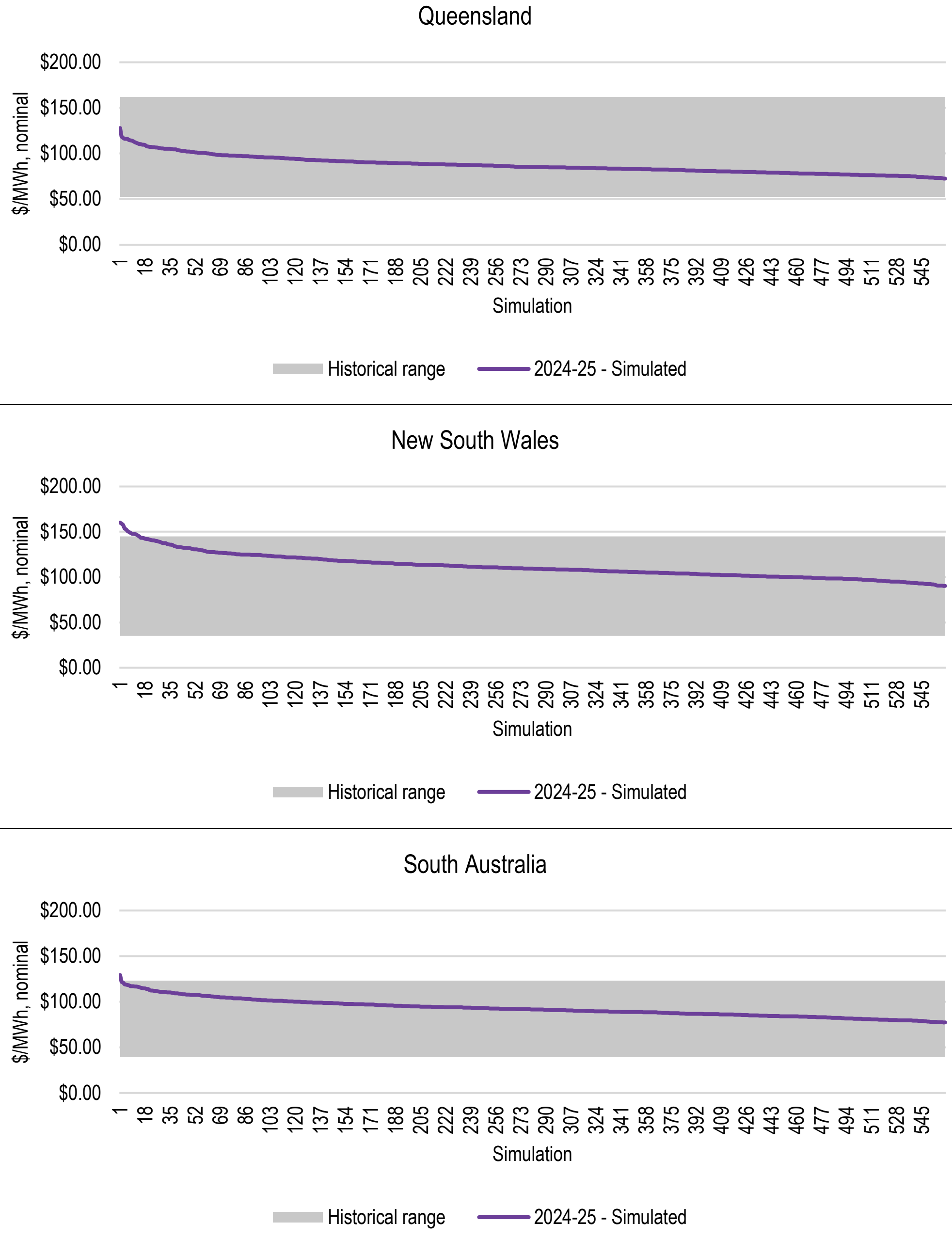


Note: Based on data available for October 2021 to June 2023.

Source: ACIL Allen analysis and AEMO data

Figure 4.15 compares the modelled annual regional TWP for the 583 simulations for 2024-25 with the regional TWPs from the past 10 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential annual price outcomes for 2024-25 when compared with the past 10 years of history.

Figure 4.15 Simulated annual TWP for Queensland, New South Wales, and South Australia for 2024-25 compared with range of actual annual outcomes in past years

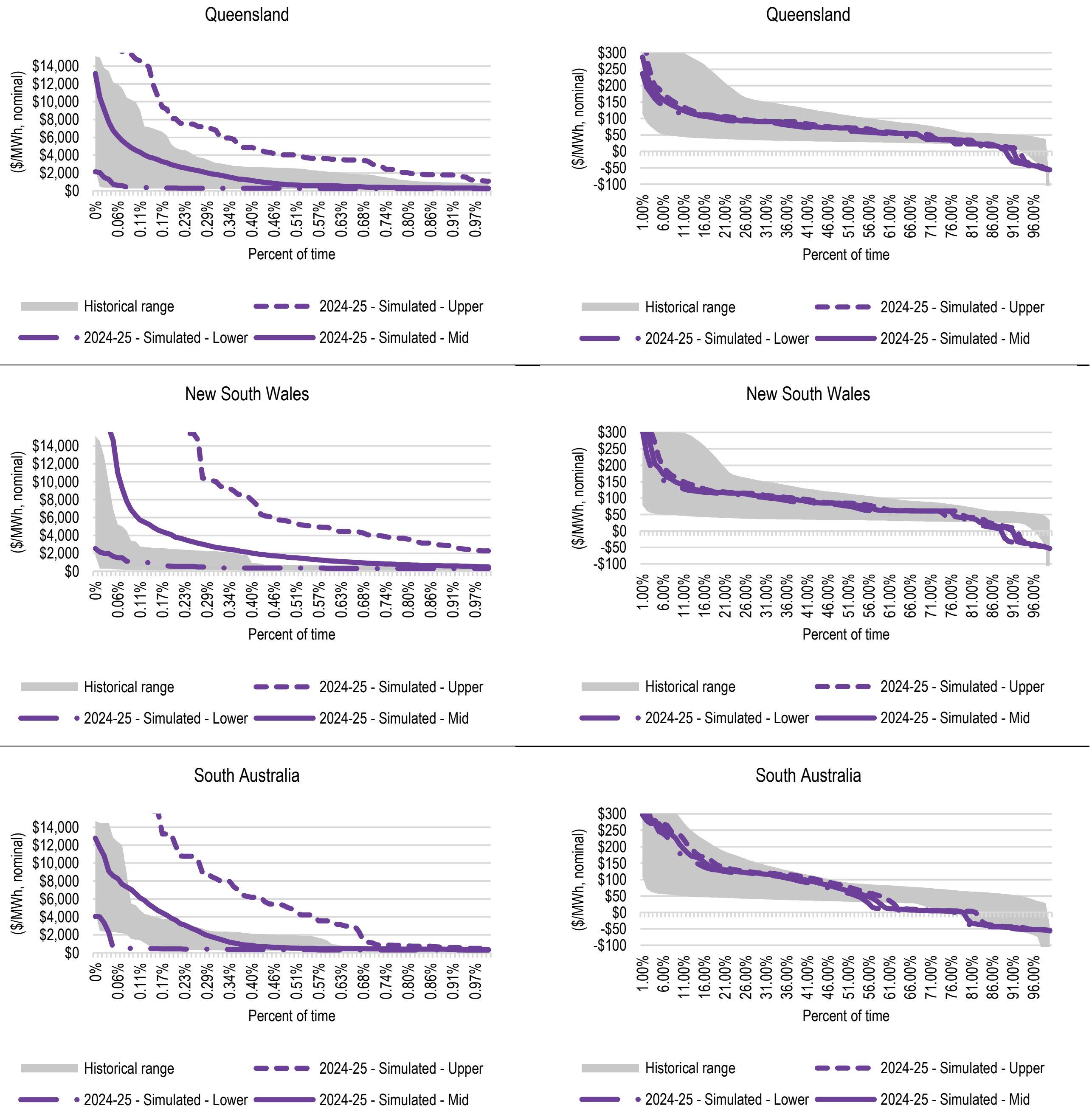


Source: ACIL Allen analysis and AEMO data

Comparing the upper one percent of hourly prices in the simulations with historical spot prices shows the spread of the hourly prices from the simulations also more than adequately covers the historical spread of spot prices, as shown in the left panel of Figure 4.16. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness. The right panel of Figure 4.16 shows the assumed implementation of the coal and gas price caps in the spot price simulations removes the recent increase in coal and gas prices which resulted in the portion of the actual spot prices below $300/MWh increasing to about $100-150/MWh. Finally, the right panel of Figure 4.16 also shows the increase in propensity for hourly prices to settle at $0/MWh or lower as a result of the continued uptake of rooftop PV, as well as the commissioning of utility scale solar projects.

The variation in the simulated hourly price duration curves in the right panels of Figure 4.16 is less than observed over the past 10 years. This is due to a single assumption of fuel prices adopted in the simulations, whereas the historical data will reflect changes in fuel prices over time.

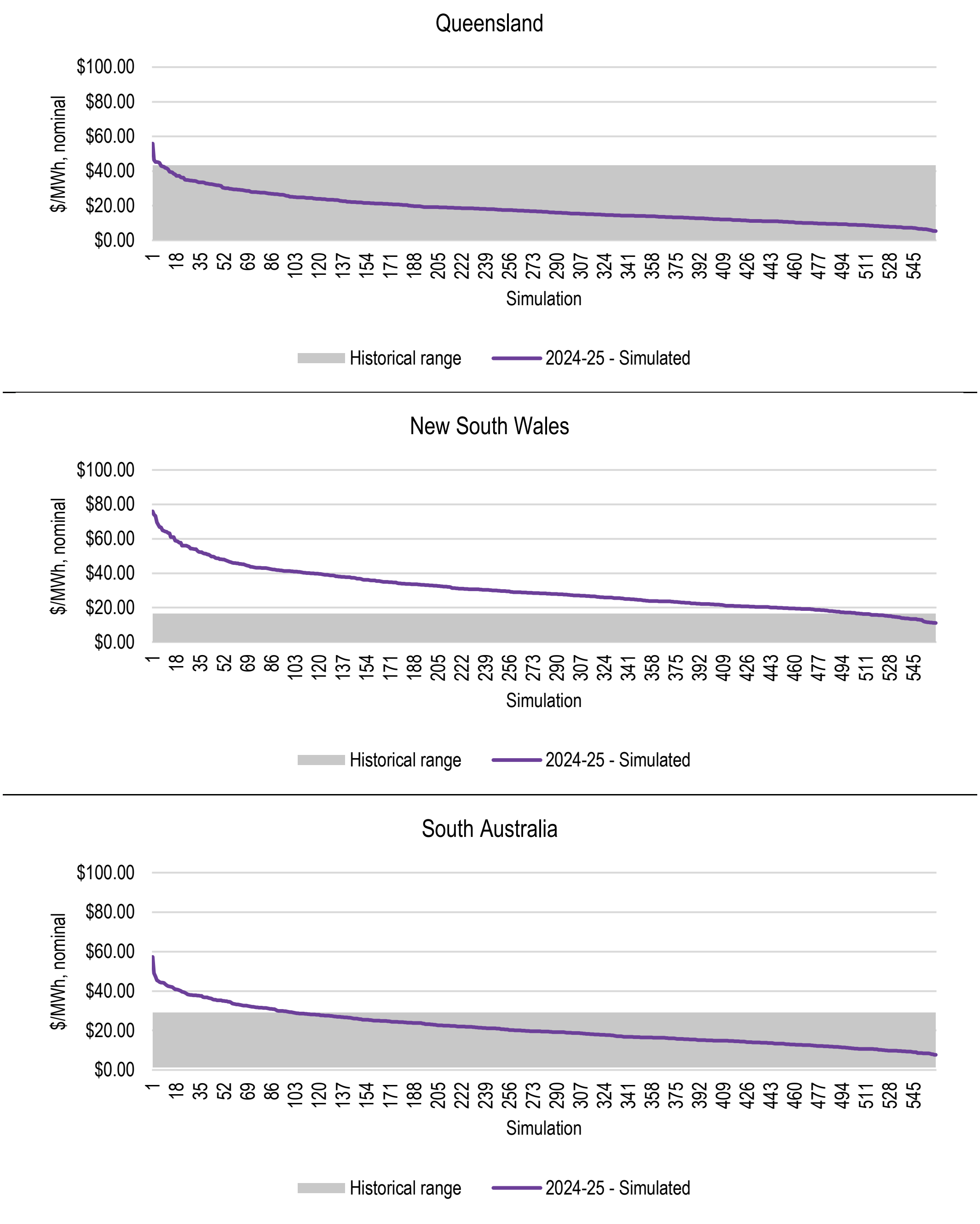
Figure 4.16 Comparison of simulated hourly price duration curves for Queensland, New South Wales, and South Australia for 2024-25 and range of actual outcomes in past years



Note: Graphs in left column show upper one per cent of price outcomes; graphs in right column show lower 99 per cent of price outcomes.
Source: ACIL Allen analysis and AEMO data

ACIL Allen is satisfied that *PowerMark* has performed adequately in capturing the extent and level of high price events based on the demand and outage inputs for the 583 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 583 simulations is consistent with those recorded in history as shown in Figure 4.17. For some of the 2024-25 simulations the contribution of price spikes is greater than historical levels, reflecting the greater variability in thermal power station availability, and the general tightening of the demand-supply balance in the market during the evening peak.

Figure 4.17 Annual average contribution to the Queensland, New South Wales, and South Australia TWP by prices above $300/MWh in 2024-25 for simulations compared with range of actual outcomes in past years



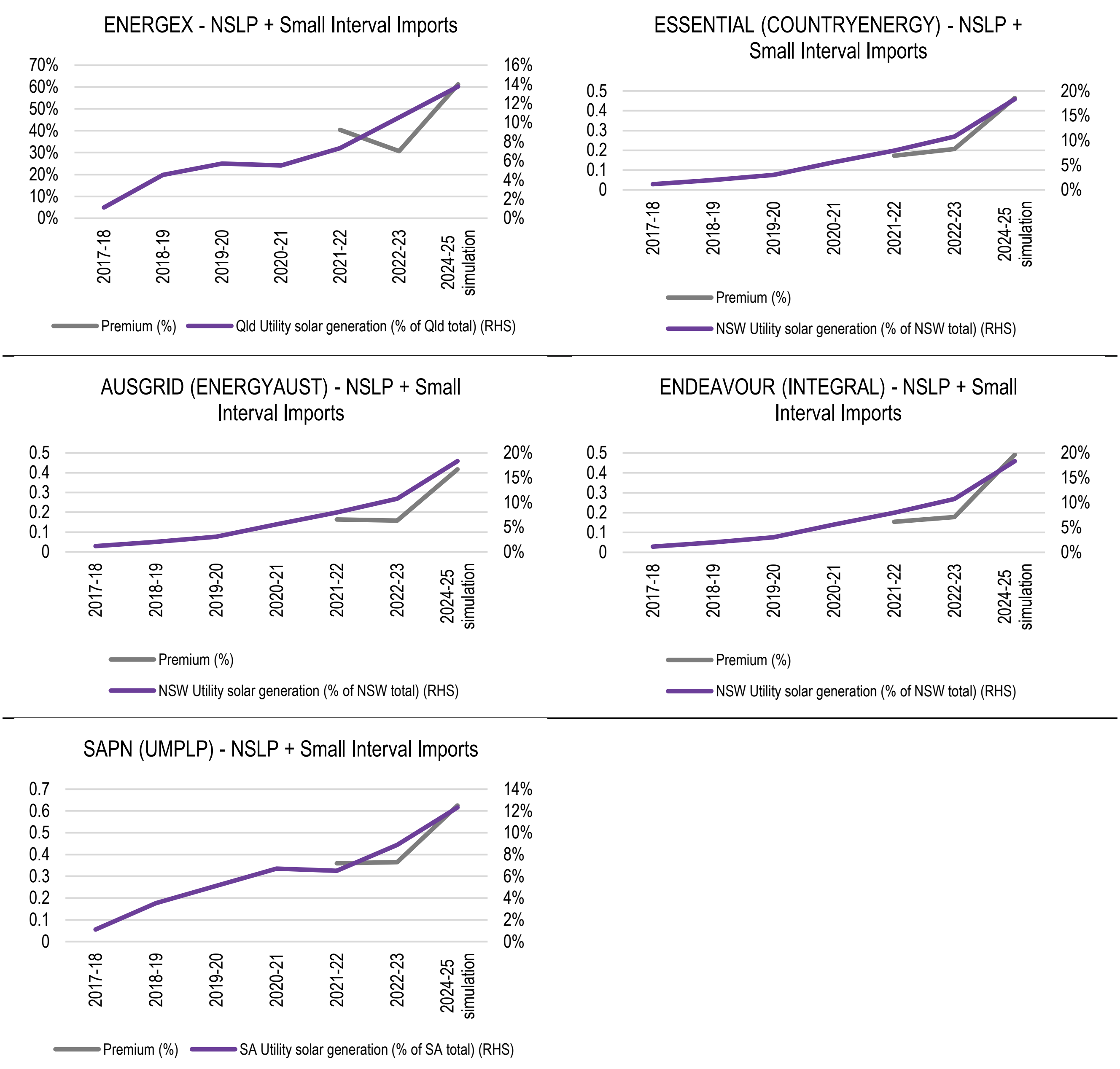
Source: ACIL Allen analysis and AEMO data

The maximum demand of the load profile is not in isolation a critical feature in determining the cost of supply. The shape and volatility of the load profile and its relationship to the shape and volatility of the regional demand/price traces is a critical factor in the cost of supplying the demand.

A test of the appropriateness of the simulated demand shape and its relationship with the regional demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the given demand profile with the corresponding regional TWP. Figure 4.18 shows that, for the past two financial years, the DWP for NSLP and small interval meter loads as a percentage premium over the corresponding regional TWPs has varied from a low of 15 percent in New South Wales to a high of 60 percent in Queensland. In the 583 simulations for 2024-25 for each NSLP and interval meter demand profile, this percentage varies from 40 percent to 60 percent.

The modelling suggests a greater range and generally higher level in the premium for 2024-25 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability coupled with a decline in price outcomes during daylight hours, due to the commissioning of utility scale PV, when the NSLP and small interval meter demand is at its lowest. Included in Figure 4.18 is a comparison showing the correlation in the growth in premium over the past few years and the increasing market share of utility scale solar output.

Figure 4.18 Simulated annual DWP for NSLP and Interval meter load as a percentage premium of annual TWP for 2024-25 compared with range of actual outcomes in past years, and market share of utility scale solar (%)



Note: Based on data available for October 2021 to June 2023.

Source: ACIL Allen analysis and AEMO data

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 583 simulations cover the range of expected price outcomes for 2024-25 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 53 simulated demand and renewable energy resource traces combined with the 11 thermal power plant outage scenarios provide a sound basis for modelling the expected future range in spot market outcomes for 2024-25.

4.2.3 Applying the hedge model

The hedging methodology uses a simple hedge book approach based on standard quarterly base swaps and cap contracts as a proxy for a retailer's hedging strategy. The prices for these hedging instruments are taken from the estimates provided in Section 4.2.1.

Contract volumes for 2024-25 are calculated for each NSLP for each quarter as follows, and are largely unchanged from DMO 3:

— The base contract volume is set to equal the 50th percentile of the off-peak period hourly demands across all 53 demand sets for the quarter.

— The cap contract volume is set at 90 per cent, for the Energex profile, and 100 per cent for the other profiles, of the median of the annual peak demands across the 53 demand sets minus the base and peak contract volumes for all profiles.

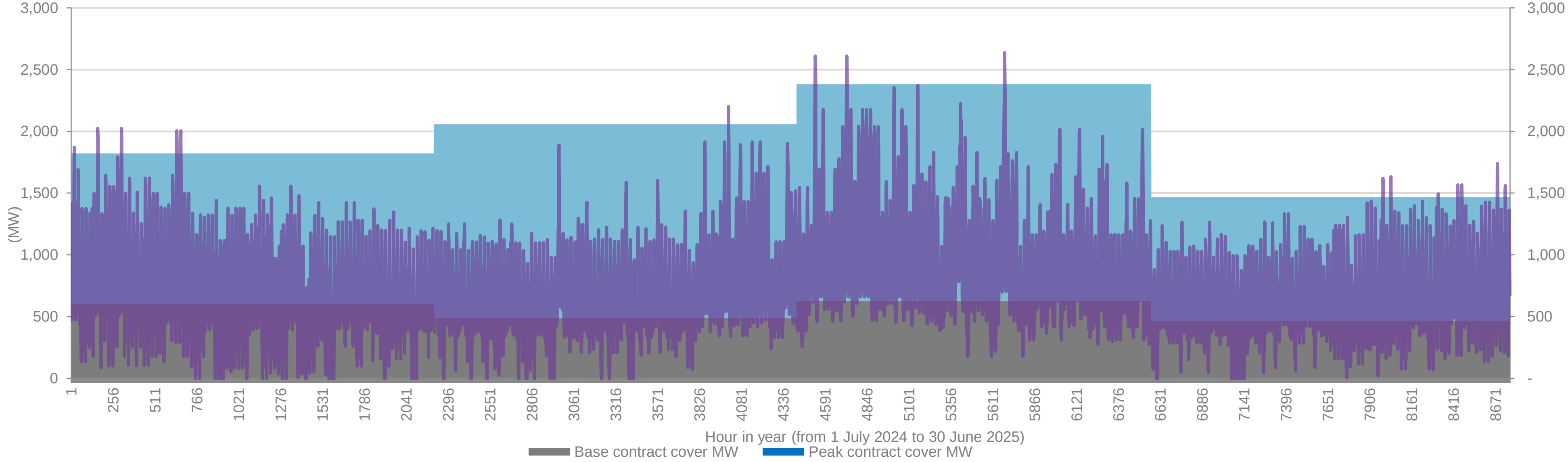
These same hourly hedge volumes (in MW terms) apply to each of the 53 demand sets for a given NSLP and year, and hence to each of the 583 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 53 demand sets. Therefore, the approach we use results in a hedging strategy that does not rely on perfect foresight but relies on an expectation of the distribution of hourly demands across a range of weather-related outcomes.

Once established, these contract volumes are then fixed across all 583 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.19 to Figure 4.23.

The contracting strategy places no reliance on peak contracts. This is not surprising – the carve out of demand during daylight hours (which makes up a reasonable part of the peak hours on business days), and the corresponding low spot prices during those hours makes the peak contacts generally unappealing. It is during these periods that the load will be over contracted and hence in effect retailers will be selling back to the market the extent of this over contracted position at the much lower spot prices. Further, the strategy's non-reliance on peak contracts matches well with the very small or nil volume of peak contracts traded relative to base contracts in the actual futures market.

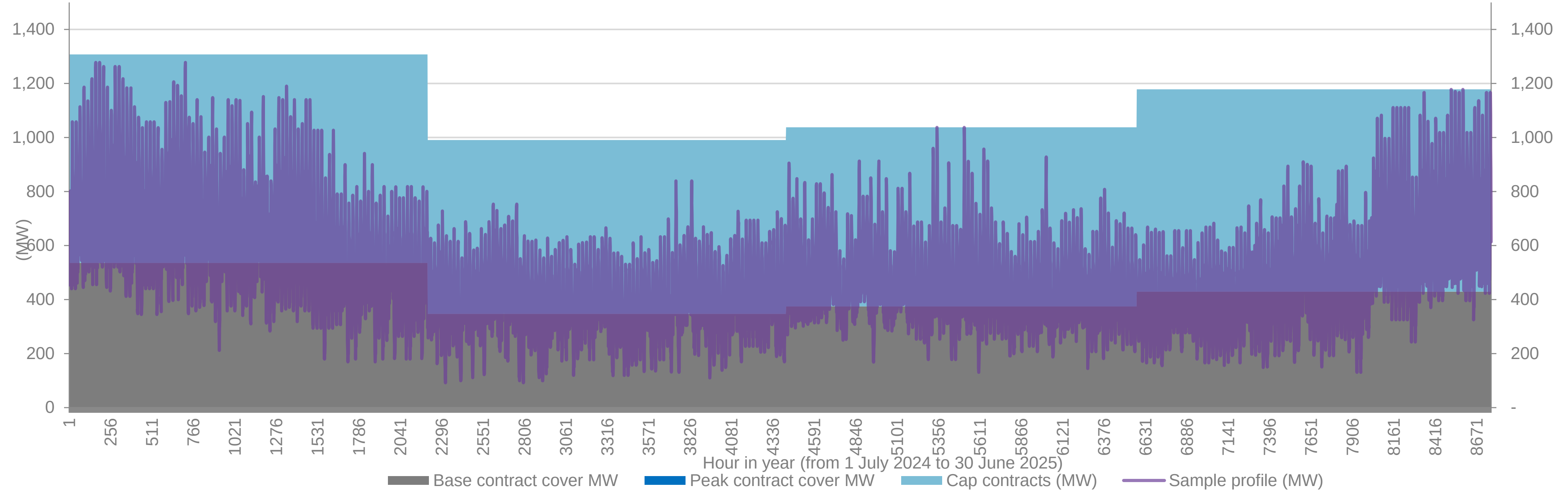
The example profiles in Figure 4.23 are from a simulation that includes loads above the P50 peak in some cases and hence are not 100 per cent covered by hedge contracts.

Figure 4.19 Contract volumes used in hedge modelling of 583 simulations for 2024-25 for Energex NSLP



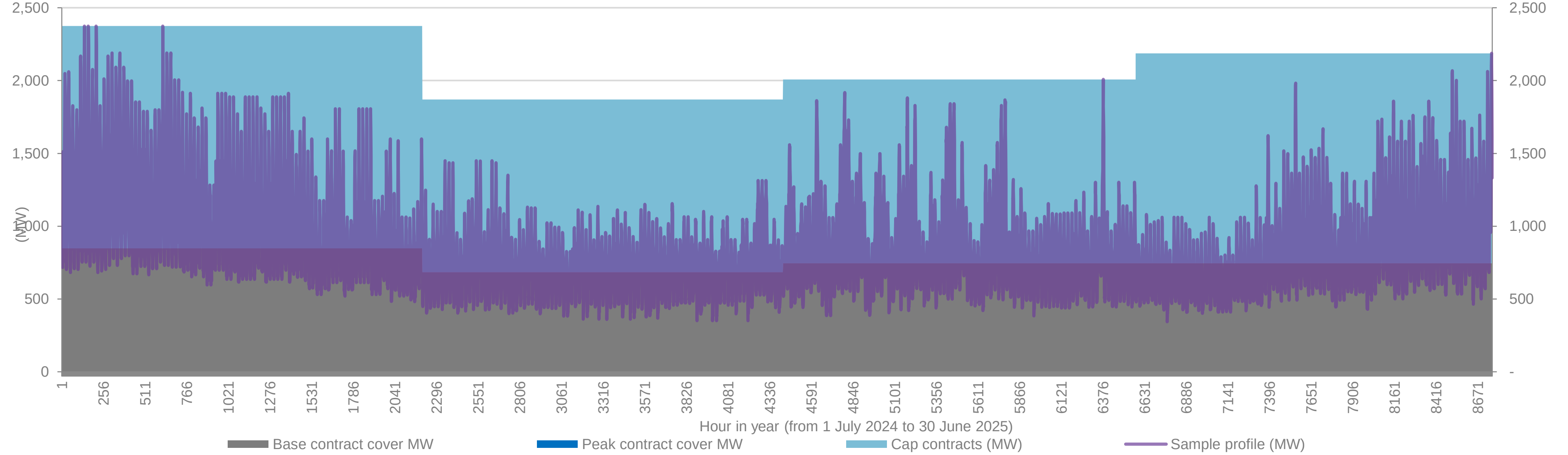
Source: ACIL Allen analysis

Figure 4.20 Contract volumes used in hedge modelling of 583 simulations for 2024-25 for Essential (COUNTRYENERGY)



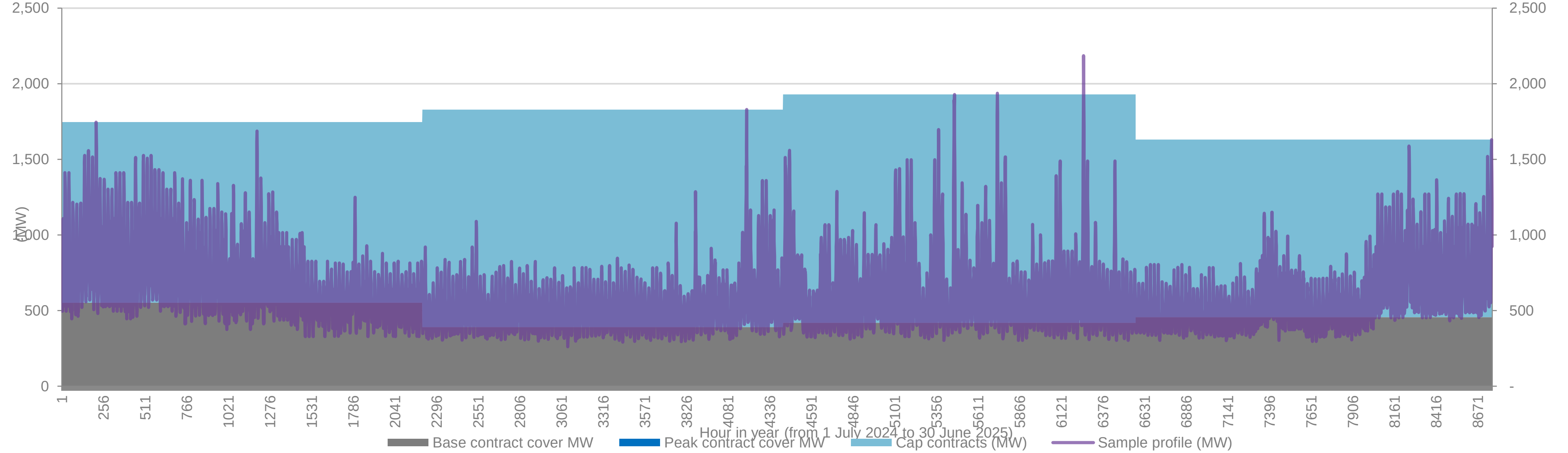
Source: ACIL Allen analysis

Figure 4.21 Contract volumes used in hedge modelling of 583 simulations for 2024-25 for Ausgrid (ENERGYAUST)



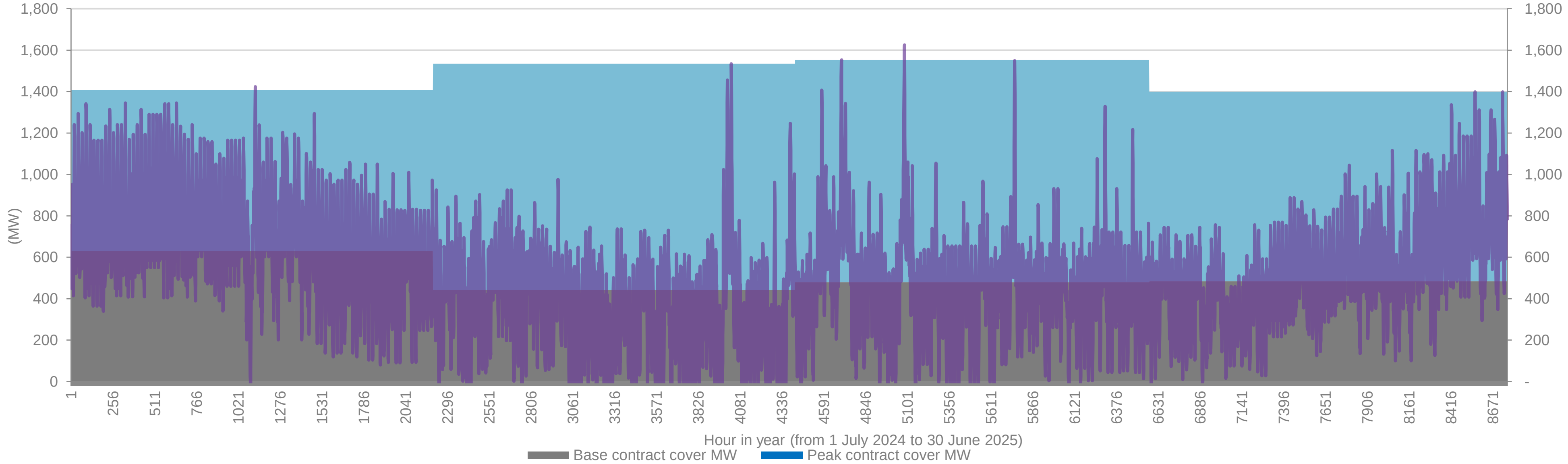
Source: ACIL Allen analysis

Figure 4.22 Contract volumes used in hedge modelling of 583 simulations for 2024-25 for Endeavour (INTEGRAL)



Source: ACIL Allen analysis

Figure 4.23 Contract volumes used in hedge modelling of 583 simulations for 2024-25 for SAPN (UMPLP)

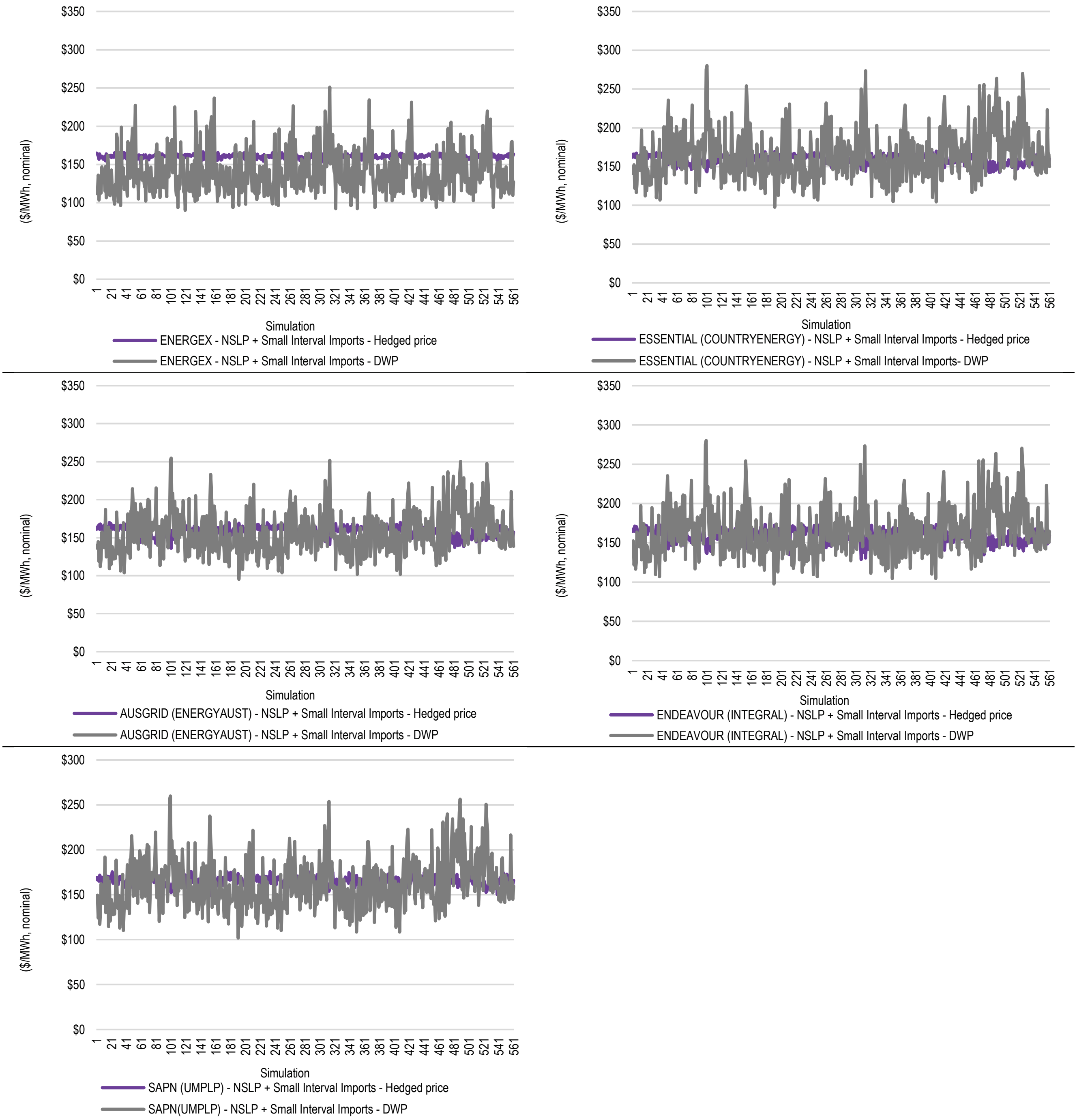


Source: ACIL Allen analysis

Figure 4.24 shows that, by using the above contracting strategies, the variation in the annual hedged price for each demand profile is far less than the variation if the profile was to be supplied without any hedging and relied solely on spot price outcomes.

It is worth noting the hedged price outcomes for the NSLP plus small interval meter load are higher than the spot price outcomes in some of the simulations. This is a result of the trade weighted average contract prices being higher than the spot price simulations, and higher than the current consensus view of outcomes for 2024-25.

Figure 4.24 Annual hedged price and DWP ($/MWh, nominal) for NSLP + small interval meter loads for the 583 simulations – 2024-25



Source: ACIL Allen analysis

4.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the final WEC estimate is taken as the 75th percentile of the distribution containing 583 WECs (the annual hedged prices). ACIL Allen's estimate of the WEC for each demand profile for 2024-25 are shown in Table 4.4 and compared to the WEC estimates in the 2023-24 Final Determination.

Table 4.4 Estimated WEC ($/MWh, nominal) for 2024-25 at the regional reference node

Settlement class	2023-24 – Final Determination	2024-25 – Draft Determination	Change from 2023-24 to 2024-25 (%)
Ausgrid – Residential and small business	$172.23	$154.72	-10.17%
Endeavour - Residential and small business	$174.45	$163.82	-6.09%
Essential - Residential and small business	$166.72	$157.63	-5.45%
Ausgrid - CLP1	$100.74	$98.16	-2.56%
Ausgrid - CLP2	$100.50	$98.30	-2.19%
Endeavour - CLP	$163.26	$99.32	-39.16%
Essential - CLP	$100.72	$98.15	-2.55%
Energex - Residential and small business	$150.91	$162.31	7.55%
Energex – CLP31	$99.82	$94.77	-5.06%
Energex – CLP33	$106.65	$101.72	-4.62%
SAPN - Residential and small business	$189.87	$168.32	-11.35%
SAPN - CLP	$85.46	$97.86	14.51%

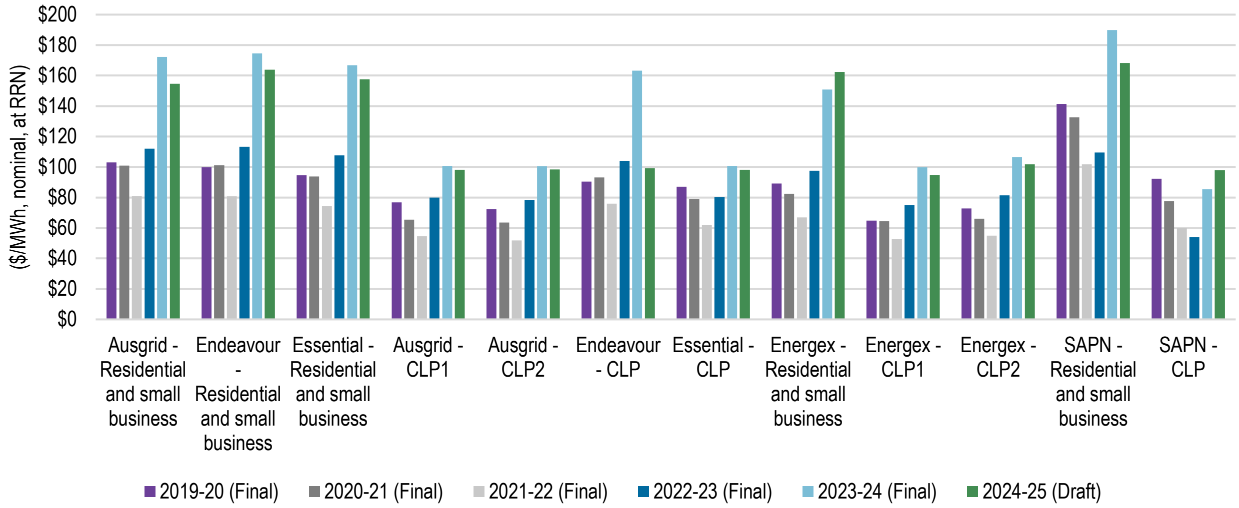
Source: ACIL Allen analysis

The 2024-25 WECs for the NSLP plus small interval meter demands decrease by between 5 and 10 per cent in New South Wales, increase by about 7.5 per cent in Queensland and decrease by about 11 per cent in South Australia compared with 2023-24 – reflecting the slight decrease or stabilising in contracts prices, and the continued decline in spot prices during daylight hours when demand is at its lowest point and hence over contracted.

As discussed earlier, the WEC for each profile is unlikely to change by the same amount between determinations – whether in dollar or percentage terms – due to their different load shapes and differences in how the load shapes and spot price shapes are changing over time.

Figure 4.25 shows the trend in WEC over the past DMO determinations.

Figure 4.25 Estimated WEC ($/MWh, nominal) for 2024-25 at the regional reference node in comparison with WECs from previous determinations



Source: ACIL Allen analysis

If the unadjusted NSLP is adopted as part of the blended demand profile for Energex and SAPN, then the estimated WECs are about 6.4% and 27.4% per cent lower respectively compared with 2023-24. These are lower than the WECs based on the blended profiles which included the removal of the temporary artificial uplift from the NSLP due to the uplift reducing the relative peakiness of the profile.

Table 4.5 Estimated WEC ($/MWh, nominal) for 2024-25 at the regional reference node – for Energex and SAPN based on unadjusted NSLP blended with interval meter demand data

Settlement class	2023-24 – Final Determination	2024-25 – Draft Determination	Change from 2023-24 to 2024-25 (%)
Energex - Residential and small business	$150.91	$141.28	-6.38%
SAPN - Residential and small business	$189.87	$137.95	-27.35%

Source: ACIL Allen analysis

4.2.5 Do the changes in WEC make intuitive sense?

Given the strong decline in wholesale spot prices over the past 12 months, one might expect a stronger decline in the 2024-25 WECs compared with what has been presented in the previous sections.

Hence the estimated WECs warrant further investigation to ensure the estimated changes align with what is observed in the market. The charts below plot the changes in WECs and trade weighted contract prices from this Determination together with previous final determinations.

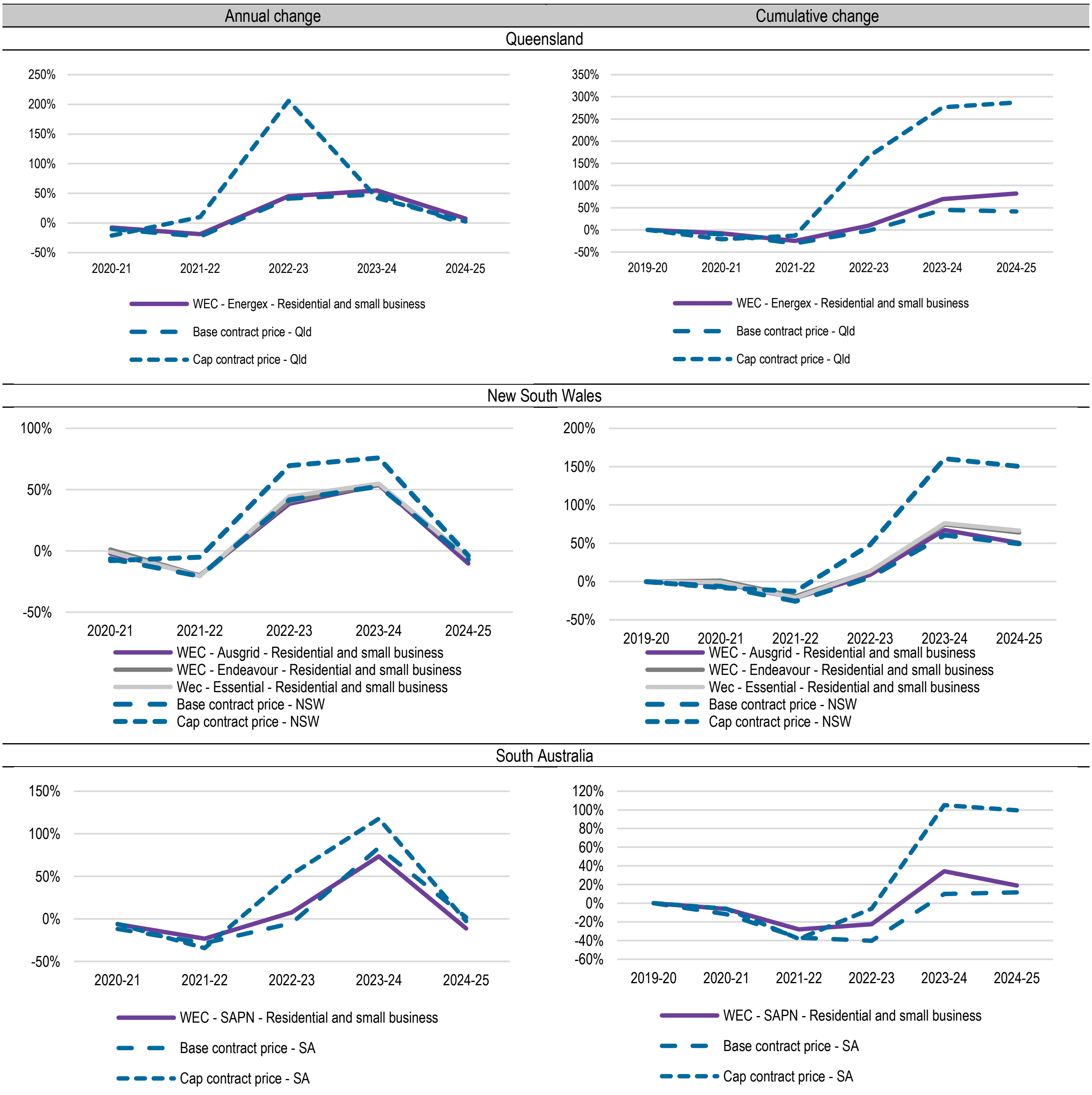
The charts in the left column plot the annual change, and the chart in the right column plot the cumulative change since 2019-20 (using 2019-20 as the base observation). Key features of the charts are:

— Overall, the year-on-year trend in estimated WECs follows the trend in contract prices.

- The trend in WECs aligns very closely to the trend in base contract prices. This is not surprising given the stronger reliance on base contracts in the hedging strategy.
- However, the trend in WEC is also influenced by the change in cap prices. The charts show changes in percentage terms, and given that cap contract prices are lower than base contract prices in dollar terms, it is not surprising that the percentage changes in cap contact prices are larger than changes in the base contract prices and WECs (since they are starting from a lower base).
- There has been no occasion in which the movement in the WEC is at odds with the movement in observable trade weighted average contract prices.

On this basis, ACIL Allen is satisfied that the methodology is appropriately estimating the WECs for 2024-25, and that the estimated WECs reflect the consensus view of market conditions for the given determination year in the two to three year period leading up to the time the determination was made – reflecting that retailers build up their hedge book over time, and in the case of 2024-25, purchased hedges in 2023-23 and 2023-24 when the expectation at that time was that prices in 2024-25 were going to remain at elevated levels.

Figure 4.26 Change in WEC and trade weighted contract prices (%) – 2019-20 to 2024-25



Note: Cumulative change uses 2019-20 as the base observation.
Source: ACIL Allen analysis

4.3 Estimation of renewable energy policy costs

Renewable energy scheme (RET)

The RET scheme consists of two elements – the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). Liable parties (i.e. all electricity retailers[14]) are required to comply and surrender certificates for both LRET and SRES.

Energy costs associated with the LRET and the SRES have been estimated using price information from brokers TraditionAsia, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen.

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2024 and 2025 calendar years, with the costs averaged to estimate the 2023-24 financial year costs.

To estimate the costs to retailers of complying with both the LRET and SRES, ACIL Allen uses the following elements:

— historical Large-scale Generation Certificate (LGC) market forward prices for 2024 and 2025 from brokers TraditionAsia
— estimated Renewable Power Percentages (RPP) values for 2024 and 2025 of 18.48 per cent[15]
— binding Small-scale Technology Percentage (STP) value for 2024 of 21.26 per cent, as published by CER
— estimated STP value for 2025 of 16.14 per cent[16]
— CER clearing house price[17] for 2023 and 2024 for Small-scale Technology Certificates (STCs) of $40/MWh.

4.3.1 LRET

To translate the aggregate LRET target for any given year into a mechanism such that liable entities under the scheme may determine how many LGCs they must purchase and acquit, the LRET legislation requires the CER to publish the RPP by 31 March within the compliance year.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the LRET scheme is derived by applying the RPP to the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail tariffs.

ACIL Allen has estimated the average LGC price using LGC forward prices provided by broker TraditionAsia up to 23 February 2024.

[14] Emissions Intensive Trade Exposed (EITE) industries such as aluminium are wholly or partially exempted and receive Partial Exemption Certificates (PEC) to be surrendered to the named liable entity.

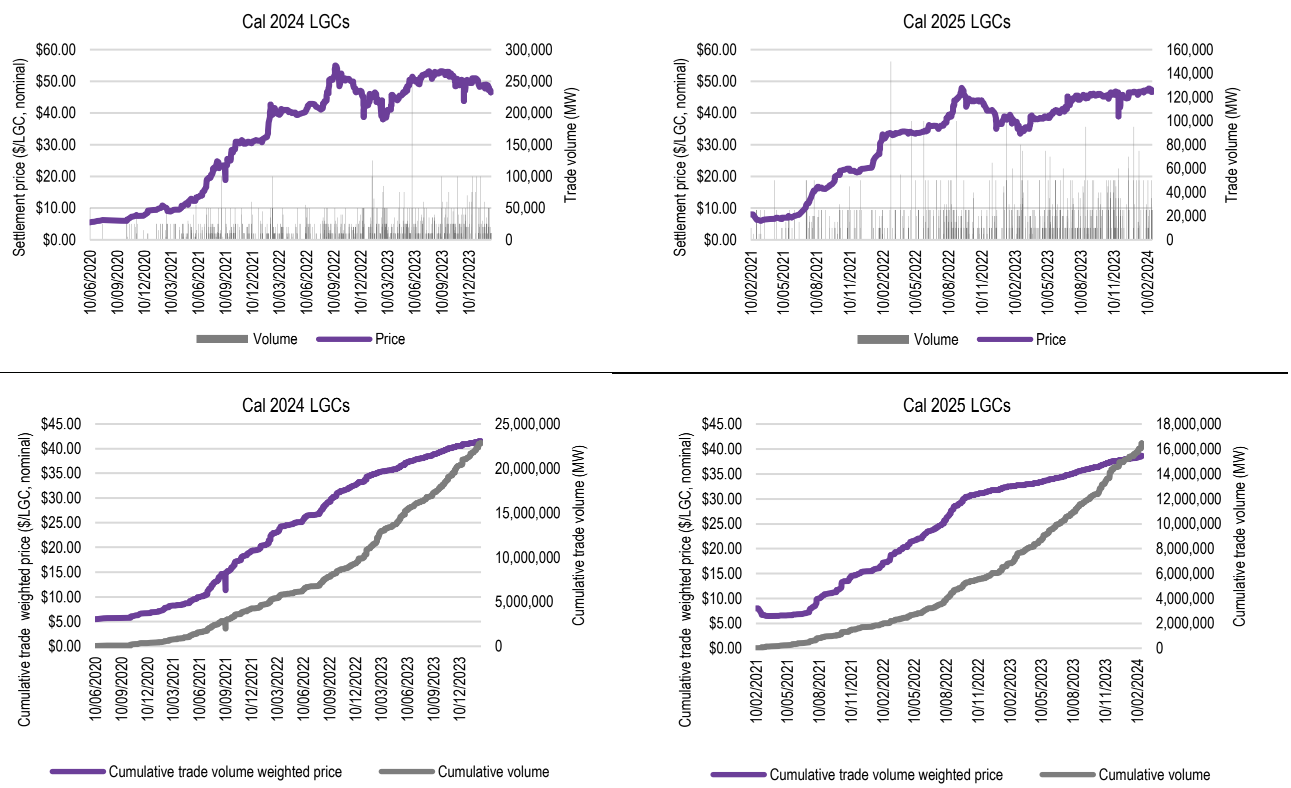
[15] The RPP values for 2024 and 2025 are based on the CER's published RPP for 2024 and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2024 and 2025.

[16] The STP value for 2025 is based on the CER's non-binding STP.

[17] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

The LGC price used in assessing the cost of the scheme for 2024-25 is found by taking the trade-weighted average of the forward prices for the 2024 and 2025 calendar years, respectively, since the contracts commenced trading. This is typically about 2.5 years prior to the commencement of the compliance year (see Figure 4.27). The average LGC prices calculated from the TraditionAsia data are $41.49/MWh for 2024 and $38.69/MWh for 2025**.**

Figure 4.27 LGC prices and trade volumes for 2024 and 2025 ($/LGC, nominal)



Source: ACIL Allen analysis of TraditionAsia

The RPP value for 2025 is yet to be set by the CER. Therefore, the RPP value for 2025 is estimated by using the mandated target of 33 TWh and the CER's published cumulative adjustment and estimate of electricity acquisitions in 2024 of 178.40 TWh. In other words, ACIL Allen has assumed electricity acquisitions remain constant in 2024 and 2025, and hence the RPP values for 2024 and 2025 are both 18.48 per cent.

Key elements of the 2024 and 2025 RPP estimation are shown in Table 4.6.

Table 4.6 Estimating the 2024 and 2025 RPP values

	2024	2025 (estimate based on 2024 RPP)
LRET target, MWh (CER)	33,981,880	33,981,880
Relevant acquisitions minus exemptions, MWh (CER)	178,400,000	178,400,000
Estimated RPP	18.48%	18.48%

Source: ACIL Allen analysis of CER data

ACIL Allen calculates the cost of complying with the LRET in 2024 and 2025 by multiplying the RPP values for 2024 and 2025 by the trade volume weighted average LGC prices for 2024 and

2025, respectively. The cost of complying with the LRET in 2024-25 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $7.41/MWh in 2024-25 as shown in Table 4.7**.**

Table 4.7 Estimated cost of LRET – 2024-25

	2024	2025	Cost of LRET 2024-25
RPP %	18.48%	18.48%	
Trade weighted average LGC price ($/LGC, nominal)	$41.49	$38.69	
Cost of LRET ($/MWh, nominal)	$7.67	$7.15	$7.41

Source: ACIL Allen analysis of CER and TFS data

4.3.2 SRES

The cost of the SRES is calculated by applying the estimated STP value to the STC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2024-25.

ACIL Allen estimates the cost of complying with SRES to be $7.48/MWh in 2024-25 as set out in Table 4.8.

Table 4.8 Estimated cost of SRES – 2024-25

	2024	2025	Cost of SRES 2024-25
STP %	21.26%	16.14%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$8.50	$6.46	$7.48

Source: ACIL Allen analysis of CER data

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2024-25 as set out in Table 4.9.

Since the 2023-24 estimate, the cost of LRET has decreased by around 0.5 per cent, driven by lower RPP in 2024-25, and the cost of SRES has increased by 9 per cent, driven by the increase in the STP.

Table 4.9 Total renewable energy policy costs ($/MWh, nominal) – 2024-25

	2023-24	2024-25
LRET	$7.44	$7.41
SRES	$6.86	$7.48
Total	**$14.30**	**$14.89**

Source: ACIL Allen analysis

4.3.4 New South Wales Energy Savings Scheme (ESS)

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

To estimate the cost of complying with the ESS, ACIL Allen uses the following elements:

- Energy Savings Scheme Target for 2024 and 2025 of 10 and 10.5 per cent respectively, as published by IPART
- Historical Energy Savings Certificate (ESC) market forward prices for 2024 and 2025 from brokers TraditionAsia.

The cost of the ESS is calculated by applying the estimated ESS target to the ESC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2024-25, as set out in Table 4.10. The 2024-25 estimate of $2.92/MWh is slightly lower than the 2023-24 estimate of $3.20/MWh – reflecting lower certificate prices which more than offset the increase in the ESS target.

Table 4.10 Estimated cost of ESS ($/MWh, nominal) – 2024-25

	2024	2025	Cost of ESS 2024-25
Average ESC price ($/MWh, nominal)	$29.62	$27.50	
ESS target	10.00%	10.50%	
Cost of ESS ($/MWh, nominal)	$2.96	$2.89	$2.92

Source: ACIL Allen analysis of IPART and TFS data

4.3.5 New South Wales Peak Demand Reduction Scheme (PDRS)

To estimate the cost of complying with the PDRS for 2024-25, ACIL Allen has used the following elements:

- The peak demand reduction target for 2024-25 of three per cent, as published by the New South Wales and Department of Planning, Industry and Environment. Using the New South Wales summer peak demand forecast for 2024-25 of 14,034 MW as published by AEMO in its 2023 ESOO, this equates to 421,012 kW of peak demand reduction.
- The peak demand period for the scheme, which is currently defined as the six-hour period between 2.30pm to 8.30pm AEST.
- A PRC trade volume weighted average PRC price of $1.59.
- The annual energy requirements for New South Wales in 2024-25 of 63,748 GWh as published by AEMO in its 2023 ESOO.

The estimated cost of the PDRS for 2024-25 is $0.63/MWh.

Table 4.11 Estimated cost of PDRS ($/MWh, nominal) – 2024-25

Item	Value
PRC price ($/PRC, nominal) per 0.1kW of peak demand reduction capacity averaged across one hour	$1.59
PDRS target (percentage reduction in peak demand)	3.0%
PDRS target (kW reduction in peak demand)	421,012
PRC target (certificates)	25,260,728
Total cost of PDRS ($, nominal)	$40,112,247
Cost of PDRS per certificate ($/PRC, nominal)	$0.29
NSW operational energy requirements (GWh)	63,748
Cost of PDRS ($/MWh)	$0.63

Source: ACIL Allen analysis

4.3.6 South Australia Retailer Energy Productivity Scheme (REPS)

The Retailer Energy Productivity Scheme (REPS) requires energy retailers with sales and customer numbers above certain thresholds (obliged retailers) to provide energy productivity activities to South Australian households and businesses to meet annual Ministerial targets. The REPS replaces the Retailer Energy Efficiency Scheme (REES), which was included in previous DMOs.

ESCOSA in its annual report on the REPS published in August 2023 reports an average cost of delivering the energy savings required under the scheme as $13.85/GJ. We multiplied the $13.85/GJ by the average of the target for 2024 and 2025 of 3,593,750 GJ, and then divided the total cost by the total customer energy in South Australia, to give a cost of $4.61/MWh.

4.4 Estimation of other energy costs

The estimates of other energy costs for the Draft Determination provided in this section consist of:

— market fees and charges including:
  – NEM management fees
  – Ancillary services costs
— pool and hedging prudential costs
— the Reliability and Emergency Reserve Trader (RERT).

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA)[18], DER and IT system upgrades for 5MS.

The estimate for the NEM management fees is taken from AEMO's latest budget and fees report for the given financial year. At this stage AEMO has not yet released its draft budget report for 2024-25, hence we have used the final 2023-24 budget report for the Draft Determination.

Based on the fees provided by AEMO's *FY24 Budget and Fees,* our estimate of the fees for 2024-25 are $0.97/MWh. The breakdown of total fees is shown in Table 4.11.

Table 4.12 NEM management fees ($/MWh, nominal) – 2024-25

Cost category	2023-24	2024-25
NEM fees (admin, registration, etc.)	$0.57	$0.57
FRC - electricity	$0.0802	$0.0937
ECA - electricity	$0.0404	$0.0404
DER fee	$0.02370	$0.02370
IT upgrade and 5MS/GS compliance	$0.2438	$0.2438
Total NEM management fees	**$0.95**	**$0.97**

Source: ACIL Allen analysis of AEMO reports

[18] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2023-24* of the assumed number of connection points for small customers used in the estimate, therefore ACIL Allen has used DNSP customer numbers to estimate the cost of ECA requirements in $/MWh terms.

4.4.2 Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs in each region over the preceding 52 weeks (as at 23 February 2024) of available NEM ancillary services data as a basis for 2024-25, the estimates cost of ancillary services is shown in Table 4.13.

Table 4.13 Ancillary services ($/MWh, nominal) – 2024-25

Region	2023-24	2024-25
Queensland	$0.47	$0.25
New South Wales	$0.46	$0.29
South Australia	$2.11	$1.04

Source: ACIL Allen analysis of AEMO data

4.4.3 Prudential costs

Prudential costs have been calculated for each jurisdiction NSLP and interval meter load profile. The prudential costs for the profiles are then used as a proxy for prudential costs for the controlled load profiles in the relevant jurisdiction.

AEMO prudential costs

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

— bank guarantees
— reallocation certificates
— prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = OSL + PML

Where for the Summer (December to March), Winter (May to August) and Shoulder (other months):

OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x (GST + 1) x 35 days

PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x (GST + 1) x 7 days

Taking a 1 MWh average daily load and assuming the inputs in Table 4.14 for each season for the Energex NSLP and small interval meter load gives an estimated MCL of $16,356.

However, as this applies for a rolling 42 days it actually covers 42 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh in the Energex NSLP is $16,356/42 = $389.43/MWh.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5 percent annual charge for 42 days or 2.5%*(42/365) = 0.288 percent. Applying this funding cost to the single MWh charge of $389.43 gives $1.12/MWh for the Energex NSLP.

The components of the AEMO prudential costs for each of the other jurisdictions' profiles are shown in Table 4.14 to Table 4.18.

Table 4.14 AEMO prudential costs for Energex – 2024-25

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$120.71	$118.88	$66.63
Participant Risk Adjustment Factor	1.8384	1.7632	1.5110
OS Volatility factor	1.52	1.55	1.39
PM Volatility factor	2.86	2.19	1.88
OSL	$17,608	$16,610	$6,623
PML	$3,522	$3,322	$1,325
MCL	$21,130	$19,932	$7,947
Average MCL		$16,356	
AEMO prudential cost ($/MWh, nominal)		**$1.12**	

Source: ACIL Allen analysis of AEMO data

Table 4.15 AEMO prudential costs for Ausgrid – 2024-25

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$125.36	$194.16	$81.19
Participant Risk Adjustment Factor	1.2486	1.3103	1.0152
OS Volatility factor	1.51	1.53	1.30
PM Volatility factor	2.89	0.00	1.83
OSL	$10,167	$17,155	$4,157
PML	$2,033	$3,431	$831
MCL	$12,201	$20,586	$4,988
Average MCL		$12,636	
AEMO prudential cost ($/MWh, nominal)		**$0.87**	

Source: ACIL Allen analysis of AEMO data

Table 4.16 AEMO prudential costs for Endeavour – 2024-25

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$125.36	$194.16	$81.19
Participant Risk Adjustment Factor	1.5399	1.3644	1.0967
OS Volatility factor	1.51	1.53	1.30
PM Volatility factor	2.89	0.00	1.83
OSL	$13,926	$18,228	$4,667
PML	$2,785	$3,646	$933

Factor	Summer	Winter	Shoulder
MCL	$16,711	$21,873	$5,600
Average MCL		$14,768	
AEMO prudential cost ($/MWh, nominal)		**$1.01**	

Source: ACIL Allen analysis of AEMO data

Table 4.17 AEMO prudential costs for Essential – 2024-25

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$125.36	$194.16	$81.19
Participant Risk Adjustment Factor	1.3634	1.2772	1.2672
OS Volatility factor	1.51	1.53	1.30
PM Volatility factor	2.89	0.00	1.83
OSL	$11,602	$16,509	$5,796
PML	$2,320	$3,302	$1,159
MCL	$13,922	$19,810	$6,956
Average MCL		$13,597	
AEMO prudential cost ($/MWh, nominal)		**$0.93**	

Source: ACIL Allen analysis of AEMO data

Table 4.18 AEMO prudential costs for SAPN – 2024-25

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$144.80	$165.27	$68.69
Participant Risk Adjustment Factor	1.5408	1.1313	1.1125
OS Volatility factor	1.77	1.57	1.44
PM Volatility factor	4.29	2.29	2.05
OSL	$18,873	$12,021	$4,468
PML	$3,775	$2,404	$894
MCL	$22,647	$14,425	$5,362
Average MCL		$14,146	
AEMO prudential cost ($/MWh, nominal)		**$0.97**	

Source: ACIL Allen analysis of AEMO data

Hedge prudential costs

ACIL Allen has relied on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The assumed money market rate is 4.35 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

We understand that the initial margin is set based on three parameters (in this case for Queensland region) being:

— the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 18 percent on average for a base contract, and 21 percent for a cap contract
— the intra monthly spread charge currently set at $12,300 for a base contract of 1 MW for a quarter, and $5,900 for a cap contract
— the spot isolation rate currently set at $1,500 for a base contract, and $600 for a cap contract.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter (rounded up) as shown for Queensland in Table 4.19. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 8.90 per cent but adjusted for an assumed 4.35 per cent return on cash lodged with the clearing (giving a net funding cost of 4.55 percent) results in the prudential cost per MWh for each contract type.

Average initial margins for Queensland, New South Wales, and South Australia, using their corresponding initial margin parameters, and the resulting prudential cost per MWh are shown in Table 4.19 to Table 4.21, respectively.

Table 4.19 Hedge Prudential funding costs by contract type – Queensland 2024-25

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$95.71	$52,000	$1.08
Cap	$24.64	$24,000	$0.50

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.20 Hedge Prudential funding costs by contract type – New South Wales 2024-25

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$115.89	$54,000	$1.12
Cap	$23.78	$23,000	$0.48

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.21 Hedge Prudential funding costs by contract type – South Australia 2024-25

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$96.35	$61,000	$1.27
Cap	$26.59	$29,000	$0.60

Source: ACIL Allen analysis of ASX Energy and RBA data

However, the hedge model used is designed to conservatively cover all load at the extremes and so results in an over-contracted position against the average load. The volume of hedges (MWh) in each category have been calculated as a proportion of the average annual load in each jurisdiction NSLP to give a proportional factor. The product of the prudential cost per MWh for each contract type and the proportion of each contract in the hedge model profile provides the total hedge prudential cost per MWh associated with each contract type. These are then summed to establish the total hedge prudential costs for each jurisdiction as shown in Table 4.22 to Table 4.26.

Table 4.22 Hedge Prudential funding costs for ENERGEX – 2024-25

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.08	0.9268	$1.00
Cap	$0.50	0.5176	$0.26
Total cost		**$1.26**	

Source: ACIL Allen analysis

Table 4.23 Hedge Prudential funding costs for Ausgrid – 2024-25

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.12	0.8874	$1.00
Cap	$0.48	1.5910	$0.76
Total cost		**$1.76**	

Source: ACIL Allen analysis

Table 4.24 Hedge Prudential funding costs for Endeavour – 2024-25

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.12	0.7446	$0.84
Cap	$0.48	2.1733	$1.04
Total cost		**$1.87**	

Source: ACIL Allen analysis

Table 4.25 Hedge Prudential funding costs for Essential – 2024-25

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.12	0.7284	$0.82
Cap	$0.48	1.6737	$0.80
Total cost		**$1.62**	

Source: ACIL Allen analysis

Table 4.26 Hedge Prudential funding costs for SAPN – 2024-25

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.27	0.9920	$1.26
Cap	$0.60	1.8787	$1.13
Total cost		**$2.39**	

Source: ACIL Allen analysis

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2024-25 as set out in Table 4.27. Prudential costs for 2024-25 are generally slightly lower than 2023-24 due to lower prices expected across 2024-25.

Table 4.27 Total prudential costs ($/MWh, nominal) – 2024-25

Jurisdiction	2023-24	2024-25
Energex NSLP	$3.27	$2.38
Ausgrid NSLP	$3.23	$2.62
Endeavour NSLP	$3.07	$2.89
Essential NSLP	$2.79	$2.55
SAPN NSLP	$3.99	$3.36

Source: ACIL Allen analysis

4.4.4 Reliability and Emergency Reserve Trader (RERT)

As with the ancillary services, we take the RERT costs as published by AEMO for the 12-month period prior to the Determination.

Excluding the June 2022 NEM events, AEMO activated the RERT once for the 12-month period prior to the Draft Determination in South Australia.

AEMO contracted 10 MW of Interim Reliability Reserve (IRR) in South Australia with a contract period from 1 December 2023 to 31 March 2024. AEMO reported the costs of this activation to be $27,300. When dividing this value by the total energy requirements in Queensland, the cost of the RERT is about 0.3 cents per MWh.

There has been no activation of the RERT (outside of the June 2022 events) in New South Wales or Queensland over the past 12 months.

4.4.5 Retailer Reliability Obligation

The RRO is not currently triggered for the DMO regions for 2024-25.

4.4.6 AEMO Direction costs

To arrive at the estimate of the AEMO Direction compensation costs, ACIL Allen takes the sum of the quarterly Direction costs by region for the most recent past four quarters, as presented in AEMO's latest available Quarterly Energy Dynamics Report (the latest report available at the time of undertaking our analysis for the Determination) and divided by the corresponding annual regional customer energy.

Direction costs in South Australia over the past 12 months equate to $8.43/MWh, a slight increase from the 2023-24 cost of $7.04/MWh – reflecting lower spot price conditions in South Australia which resulted lower levels of gas fired generation. Hence, AEMO issued more directions to maintain minimum synchronous generation levels to ensure system security.

These directions costs exclude those related to the June 2022 NEM events.

4.4.7 June 2022 NEM events

To estimate the costs of the June 2022 NEM events, ACIL Allen uses AEMO's published estimates of the costs of the June 2022 events, as well as AEMC's final decisions on administered pricing compensation claims.

At this stage no updated finalised costs have been published since the 2023-24 Final Determination. We will continue to monitor the AEMC publications between now and the Final Determination.

4.4.8 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.28 and Table 4.29, for the 2024-25 Draft Determination and is compared with the costs for 2023-24.

Table 4.28 Total of other costs ($/MWh, nominal) – Energex – 2024-25

Cost category	2023-24	2024-25
NEM management fees	$0.95	$0.97
Ancillary services	$0.47	$0.25
Hedge and pool prudential costs	$3.27	$2.38
Reserve and Emergency Reserve Trader costs	$0.04	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.90	$0.00
Total	**$5.63**	**$3.60**

Source: ACIL Allen analysis

Table 4.29 Total of other costs ($/MWh, nominal) – Ausgrid – 2024-25

Cost category	2023-24	2024-25
NEM management fees	$0.95	$0.97
Ancillary services	$0.46	$0.29
Hedge and pool prudential costs	$3.23	$2.62
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$2.06	$0.00
Total	**$6.70**	**$3.88**

Source: ACIL Allen analysis

Table 4.30 Total of other costs ($/MWh, nominal) – Endeavour – 2024-25

Cost category	2023-24	2024-25
NEM management fees	$0.95	$0.97
Ancillary services	$0.46	$0.29
Hedge and pool prudential costs	$3.07	$2.89
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$2.65	$0.00
Total	**$6.54**	**$4.15**

Source: ACIL Allen analysis

Table 4.31 Total of other costs ($/MWh, nominal) – Essential – 2024-25

Cost category	2023-24	2024-25
NEM management fees	$0.95	$0.97
Ancillary services	$0.46	$0.29
Hedge and pool prudential costs	$2.79	$2.55
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$2.06	$0.00
Total	**$6.26**	**$3.81**

Source: ACIL Allen analysis

Table 4.32 Total of other costs ($/MWh, nominal) – SAPN – 2024-25

Cost category	2023-24	2024-25
NEM management fees	$0.95	$0.97
Ancillary services	$2.11	$1.04
Hedge and pool prudential costs	$3.99	$3.36
Reserve and Emergency Reserve Trader costs	$0.00	$0.003
AEMO Direction costs	$7.04	$8.43
June 2022 NEM events	$0.68	$0.00
Total	**$14.77**	**$13.80**

Source: ACIL Allen analysis

4.5 Estimation of energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the Regional Reference Node (RRN). These estimates need to be adjusted for transmission and distribution losses associated with transmitting energy from the Regional Reference Node to end-users. Distribution Loss Factors (DLF) for each jurisdiction and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the wholesale energy cost estimates to incorporate losses.

The MLFs and DLFs used to estimate losses for this Determination are based on the preliminary draft 2024-25 MLFs and final 2023-24 DLFs published by AEMO in February 2024 and April 2023 respectively. These will be updated for the Final Determination based on the final MLFs and DLFs expected to be published around March / April 2024.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2024-25 is shown in Table 4.33.

Table 4.33 Estimated transmission and distribution losses

	2023-24			2024-25		
	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Ausgrid – Residential and small business	4.82%	-0.81%	1.040	4.82%	0.15%	1.050
Endeavour - Residential and small business	6.91%	-2.02%	1.047	6.91%	-0.90%	1.059
Essential - Residential and small business	5.88%	-2.80%	1.029	5.88%	-3.15%	1.025
Ausgrid - CLP1	5.05%	-0.81%	1.042	5.05%	0.15%	1.052
Ausgrid - CLP2	5.05%	-0.81%	1.042	5.05%	0.15%	1.052
Endeavour - CLP	6.91%	-2.02%	1.047	6.91%	-0.90%	1.059
Essential - CLP	5.88%	-2.80%	1.029	5.88%	-3.15%	1.025
Energex - Residential and small business	5.91%	0.72%	1.067	5.91%	0.71%	1.067
Energex – CLP31	5.91%	0.72%	1.067	5.91%	0.71%	1.067
Energex – CLP33	5.91%	0.72%	1.067	5.91%	0.71%	1.067
SAPN - Residential and small business	11.09%	-0.50%	1.105	11.09%	-0.78%	1.102
SAPN - CLP	11.09%	-0.50%	1.105	11.09%	-0.78%	1.102

Source: ACIL Allen analysis of AEMO data

As described by AEMO[19], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

*Price at load connection point = RRN Spot Price * (MLF * DLF)*

[19] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

4.6 Summary of estimated energy costs

Drawing together the analyses and estimates from the previous sections of this report, ACIL Allen's estimates of the 2024-25 total energy costs (TEC) for the Draft Determination for each of the profiles are presented in Table 4.33 and Table 4.36.

Table 4.34 Estimated TEC for 2024-25 ($/MWh, nominal) – Draft Determination

Profile	2023-24 Total energy costs at the customer terminal ($/MWh, nominal)	2024-25 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2023-24 to 2024-25 ($/MWh, nominal)	Change from 2023-24 to 2024-25 (%, nominal)
Ausgrid – Residential and small business	$204.77	$185.89	($18.88)	-9.22%
Endeavour - Residential and small business	$208.30	$197.41	($10.89)	-5.23%
Essential - Residential and small business	$196.48	$184.38	($12.10)	-6.16%
Ausgrid - CLP1	$130.66	$126.75	($3.91)	-2.99%
Ausgrid - CLP2	$130.41	$126.89	($3.52)	-2.70%
Endeavour - CLP	$196.58	$129.10	($67.48)	-34.33%
Essential - CLP	$128.56	$123.41	($5.15)	-4.01%
Energex - Residential and small business	$182.29	$192.92	$10.63	5.83%
Energex – CLP31	$127.78	$120.85	($6.93)	-5.42%
Energex – CLP33	$135.06	$128.27	($6.79)	-5.03%
SAPN - Residential and small business	$245.46	$222.19	($23.27)	-9.48%
SAPN - CLP	$130.08	$144.54	$14.46	11.12%

Source: ACIL Allen analysis

If the unadjusted NSLP is adopted as part of the blended demand profile for Energex and SAPN, then the estimated TECs are about 6.5% and 23.1% per cent lower respectively compared with 2023-24.

Table 4.35 Estimated TEC for 2024-25 ($/MWh, nominal) – for Energex and SAPN based on unadjusted NSLP blended with interval meter demand data – Draft Determination

Profile	2023-24 Total energy costs at the customer terminal ($/MWh, nominal)	2024-25 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2023-24 to 2024-25 ($/MWh, nominal)	Change from 2023-24 to 2024-25 (%, nominal)
Energex - Residential and small business	$182.29	$170.48	($11.81)	-6.48%
SAPN - Residential and small business	$245.46	$188.72	($56.74)	-23.12%

Source: ACIL Allen analysis

Table 4.36 Estimated TEC for 2024-25 Draft Determination ($/MWh, nominal)

Profile	WEC at regional reference node ($/MWh, nominal)	Other wholesale costs at regional reference node ($/MWh, nominal)	Network loss factor	Wholesale network losses ($/MWh, nominal)	Total wholesale costs at the customer terminal ($/MWh, nominal)	LRET costs at regional reference node ($/MWh, nominal)	SRES costs at regional reference node ($/MWh, nominal)	Other environmental costs at regional reference node ($/MWh, nominal)	Environmental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid – Residential and small business	$154.72	$3.88	1.050	$7.93	$166.53	$7.41	$7.48	$3.55	$0.92	$19.36	$185.89
Endeavour - Residential and small business	$163.82	$4.15	1.059	$9.91	$177.88	$7.41	$7.48	$3.55	$1.09	$19.53	$197.41
Essential - Residential and small business	$157.63	$3.81	1.025	$4.04	$165.48	$7.41	$7.48	$3.55	$0.46	$18.90	$184.38
Ausgrid - CLP1	$98.16	$3.88	1.052	$5.31	$107.35	$7.41	$7.48	$3.55	$0.96	$19.40	$126.75
Ausgrid - CLP2	$98.30	$3.88	1.052	$5.31	$107.49	$7.41	$7.48	$3.55	$0.96	$19.40	$126.89
Endeavour - CLP	$99.32	$4.15	1.059	$6.10	$109.57	$7.41	$7.48	$3.55	$1.09	$19.53	$129.10
Essential - CLP	$98.15	$3.81	1.025	$2.55	$104.51	$7.41	$7.48	$3.55	$0.46	$18.90	$123.41
Energex - Residential and small business	$162.31	$3.60	1.067	$11.12	$177.03	$7.41	$7.48	$0.00	$1.00	$15.89	$192.92
Energex – CLP31	$94.77	$3.60	1.067	$6.59	$104.96	$7.41	$7.48	$0.00	$1.00	$15.89	$120.85
Energex – CLP33	$101.72	$3.60	1.067	$7.06	$112.38	$7.41	$7.48	$0.00	$1.00	$15.89	$128.27
SAPN - Residential and small business	$168.32	$13.80	1.102	$18.58	$200.70	$7.41	$7.48	$4.61	$1.99	$21.49	$222.19
SAPN - CLP	$97.86	$13.80	1.102	$11.39	$123.05	$7.41	$7.48	$4.61	$1.99	$21.49	$144.54

Source: ACIL Allen analysis

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