ACIL ALLEN

23 May 2023

Report to Australian Energy Regulator

Default Market Offer 2023-24

Wholesale energy and environment cost estimates for DMO 5 Final 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 2023-24: Wholesale energy and environmental cost estimates for DMO 5 Final Determination, ACIL Allen, May 2023

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Executive summary

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 2023-24 (DMO 5). 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 Final Determination, using the methodology in our 2022-23 (DMO 4) Final Determination report to the AER, as well as considering stakeholder feedback in response to the AER's Issues Paper, Draft Determination, as well as feedback from the AER.

Summary of estimated energy costs

ACIL Allen's estimates of the 2023-24 total wholesale energy costs, environmental costs and total energy costs (TEC) for the Final Determination for each of the regional tariff profiles are presented in Table ES 1.

Table ES 1 Estimated TEC components for 2023-24 Final Determination ($/MWh, nominal)

Profile	Total wholesale costs at the customer terminal ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid – NSLP	$186.09	$18.68	$204.77
Endeavour - NSLP	$189.50	$18.80	$208.30
Essential - NSLP	$178.00	$18.48	$196.48
Ausgrid - CLP1	$111.95	$18.71	$130.66
Ausgrid - CLP2	$111.70	$18.71	$130.41
Endeavour - CLP	$177.78	$18.80	$196.58
Essential – CLP	$110.08	$18.48	$128.56
Energex – NSLP	$167.03	$15.26	$182.29
Energex – CLP31	$112.52	$15.26	$127.78
Energex – CLP33	$119.80	$15.26	$135.06
SAPN – NSLP	$226.13	$19.33	$245.46
SAPN – CLP	$110.75	$19.33	$130.08

Source: ACIL Allen analysis

The change, in $/MWh and percentage terms, in the estimated total energy costs between the 2022-23 DMO 4 Final Determination and 2023-24 DMO 5 Final Determination are shown in Table ES 2 and Figure ES 1.

Table ES 2 Estimated TEC for 2023-24 ($/MWh, nominal) – Final Determination

Profile	2022-23 Total energy costs at the customer terminal ($/MWh, nominal)	2023-24 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2022-23 to 2023-24 ($/MWh, nominal)	Change from 2022-23 to 2023-24 (%, nominal)
Ausgrid - NSLP	$142.91	$204.77	$61.86	43.29%
Endeavour - NSLP	$145.07	$208.30	$63.23	43.59%
Essential - NSLP	$136.42	$196.48	$60.06	44.03%
Ausgrid - CLP1	$109.36	$130.66	$21.30	19.48%
Ausgrid - CLP2	$108.00	$130.41	$22.41	20.75%
Endeavour - CLP	$135.32	$196.58	$61.26	45.27%
Essential - CLP	$107.93	$128.56	$20.63	19.11%
Energex - NSLP	$127.63	$182.29	$54.66	42.83%
Energex – CLP31	$103.75	$127.78	$24.03	23.16%
Energex – CLP33	$110.57	$135.06	$24.49	22.15%
SAPN - NSLP	$154.91	$245.46	$90.55	58.45%
SAPN - CLP	$93.90	$130.08	$36.18	38.53%

Source: ACIL Allen analysis

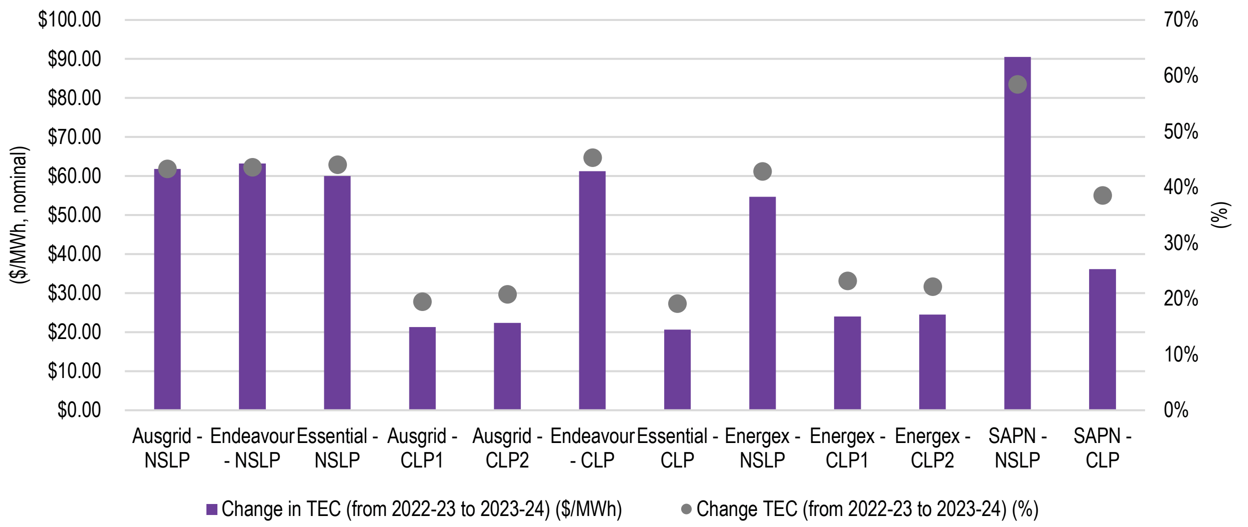
The change, in percentage terms, in the estimated energy cost components between the 2022-23 DMO 4 Final Determination and 2023-24 DMO 5 Final Determination are set out in Table ES 3.

Table ES 3 Change in estimated energy cost components between 2022-23 and 2023-24 (%) – Final Determination

Profile	Change in total wholesale energy cost (%)	Change in total environmental cost (%)	Change in total energy cost (TEC) (%)
Ausgrid - NSLP	52.25%	-9.67%	43.29%
Endeavour - NSLP	52.52%	-9.70%	43.59%
Essential - NSLP	53.49%	-9.63%	44.03%
Ausgrid - CLP1	26.33%	-9.79%	19.48%
Ausgrid - CLP2	28.01%	-9.79%	20.75%
Endeavour - CLP	55.27%	-9.70%	45.27%
Essential - CLP	25.83%	-9.63%	19.11%
Energex - NSLP	51.12%	-10.76%	42.83%
Energex – CLP31	29.86%	-10.76%	23.16%
Energex – CLP33	28.17%	-10.76%	22.15%
SAPN - NSLP	68.09%	-5.15%	58.45%
SAPN - CLP	50.64%	-5.15%	38.53%

Source: ACIL Allen analysis

Figure ES 1 Change in estimated TEC between 2022-23 and 2023-24 ($/MWh, and %) – Final Determination



Source: ACIL Allen analysis

The key drivers for these changes are:

- **Total wholesale energy costs:**
  - **Wholesale energy costs (WEC) (a sub-component of total wholesale energy cost):** the key drivers in the change in wholesale energy costs are the change in contract prices and the time-of-day shape of the load profiles and spot price outcomes. Compared with 2022-23, futures base contract prices for 2023-24, on an annualised and trade weighted basis to date, have:
    - increased by about $32.00/MWh for Queensland
    - increased by about $43.70/MWh for New South Wales
    - increased by about $44.30/MWh for South Australia.
  - Cap contract prices for 2023-24 have increased noticeably compared with 2022-23, and on an annualised and trade weighted basis to date, have:
    - increased by about $7.20/MWh for Queensland
    - increased by about $10.90/MWh for New South Wales
    - increased by about $14.80/MWh for South Australia.
  - Unlike the three determinations spanning 2019-20 to 2021-22 in which there was a clear decline in contract prices, the market is clearly expecting the higher price outcomes experienced in 2022-23 to continue into 2023-24, due to the relatively stronger coal and gas costs, coupled with the closure of Liddell in New South Wales, and the delayed return of Callide C in Queensland. more than offsetting the amount of utility scale renewable investment coming on-line between 2022-23 and 2023-24. Although the Government's intervention on coal and gas prices has reduced the market's expectations on wholesale electricity wholesale spot prices for 2023-24, the trade weighted average futures prices remain elevated relative to 2022-23 since a large portion of hedges were purchased prior to the announcement of the Government's intervention.
  - The cost of hedging the NSLP demand profile will be further exacerbated by the expected continued uptake of rooftop PV which carves out the demand during daylight hours, coupled with the commissioning of over 4,000 MW of utility scale solar, resulting in very low spot price outcomes during daylight hours, certainly less than the base contact price, making the already peaky NSLP demand profile more expensive to hedge.
  - **Other energy costs (a sub-component of total wholesale energy cost):**

- The most substantial change in other wholesale energy costs is the inclusion of the costs associated with compensation recovery related to the June 2022 events that triggered administered pricing, spot market suspension and market interventions in the NEM consistent with the National Electricity Rules (NER). This component has added around $2.10/MWh in NSW, around $0.90/MWh in Queensland, and around $0.70/MWh in South Australia.
- Ancillary services recovery costs in South Australia have increased significantly, by around $1.60/MWh due to the weather-related islanding event in mid-November, which resulted in volatile FCAS prices. Ancillary service costs are estimated by the most recent 52 weeks of actual cost data as published by AEMO.

— **Environmental costs:** environmental costs are estimated to decrease across all regions slightly (on average by about $2/MWh). There is a projected increase in LRET costs between 2022-23 and 2023-24 due to an increase in LGC contract prices. This is more than offset by a projected decline in the cost of the SRES between 2022-23 and 2023-24. Although there is an expectation that small-scale installations in 2023 and 2024 will remain at similar levels observed in 2022, the cost of the scheme decreases due to the shortening of the deeming period. The total environmental cost variations by region are mainly a result of differences in jurisdictional energy efficiency schemes.

1 Introduction

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 2023-24 (DMO 5).

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 Final Determination for DMO 5, using the methodology in our 2022-23 (DMO 4) Final Determination report to the AER, as well as considering stakeholder feedback in response to the AER's Issues Paper and Draft Determination.

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 2023-24: Draft Determination* (15 March 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.

2 Overview of approach

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 5, 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

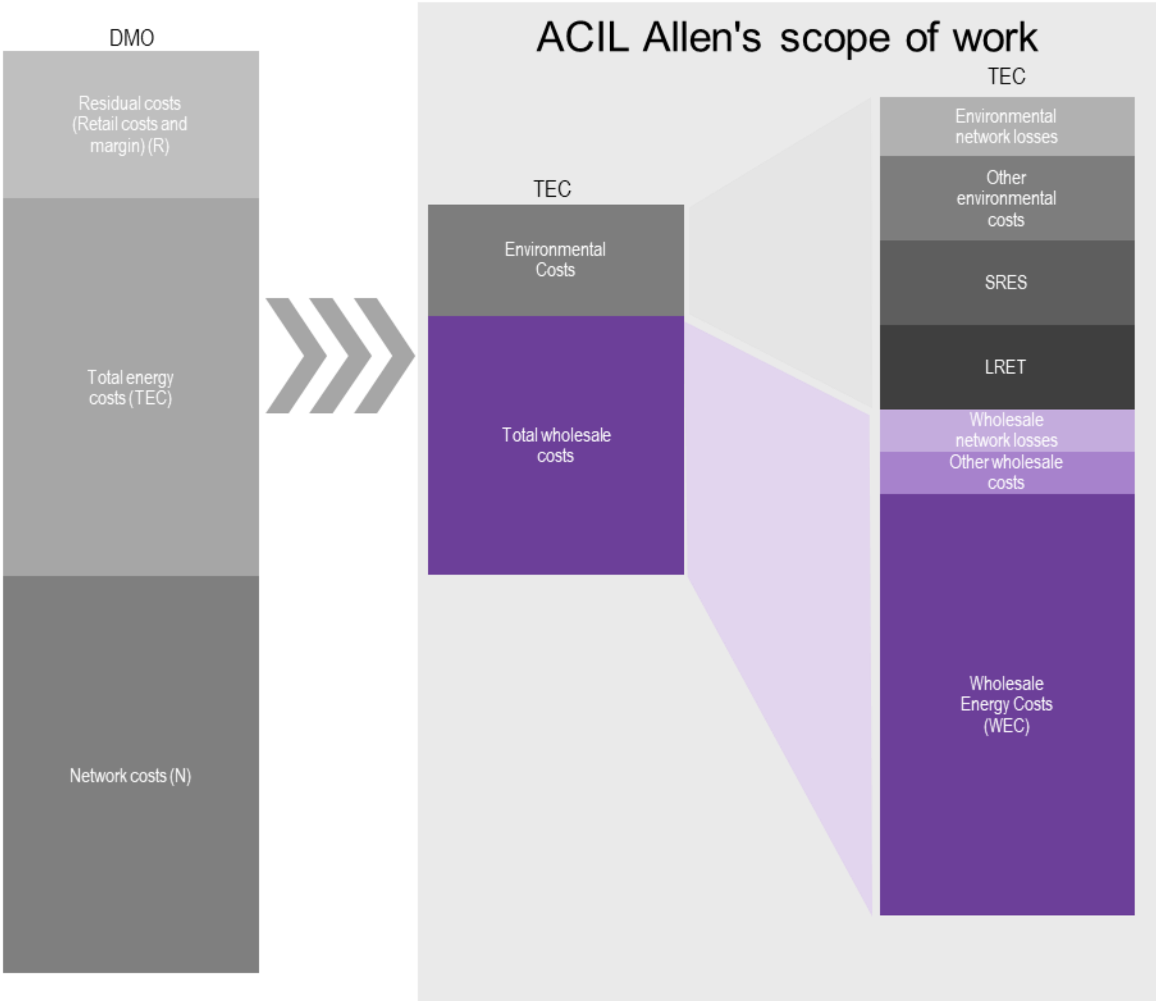
— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET).

— 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.

— 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 5 (and DMO 2 to 4) 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:

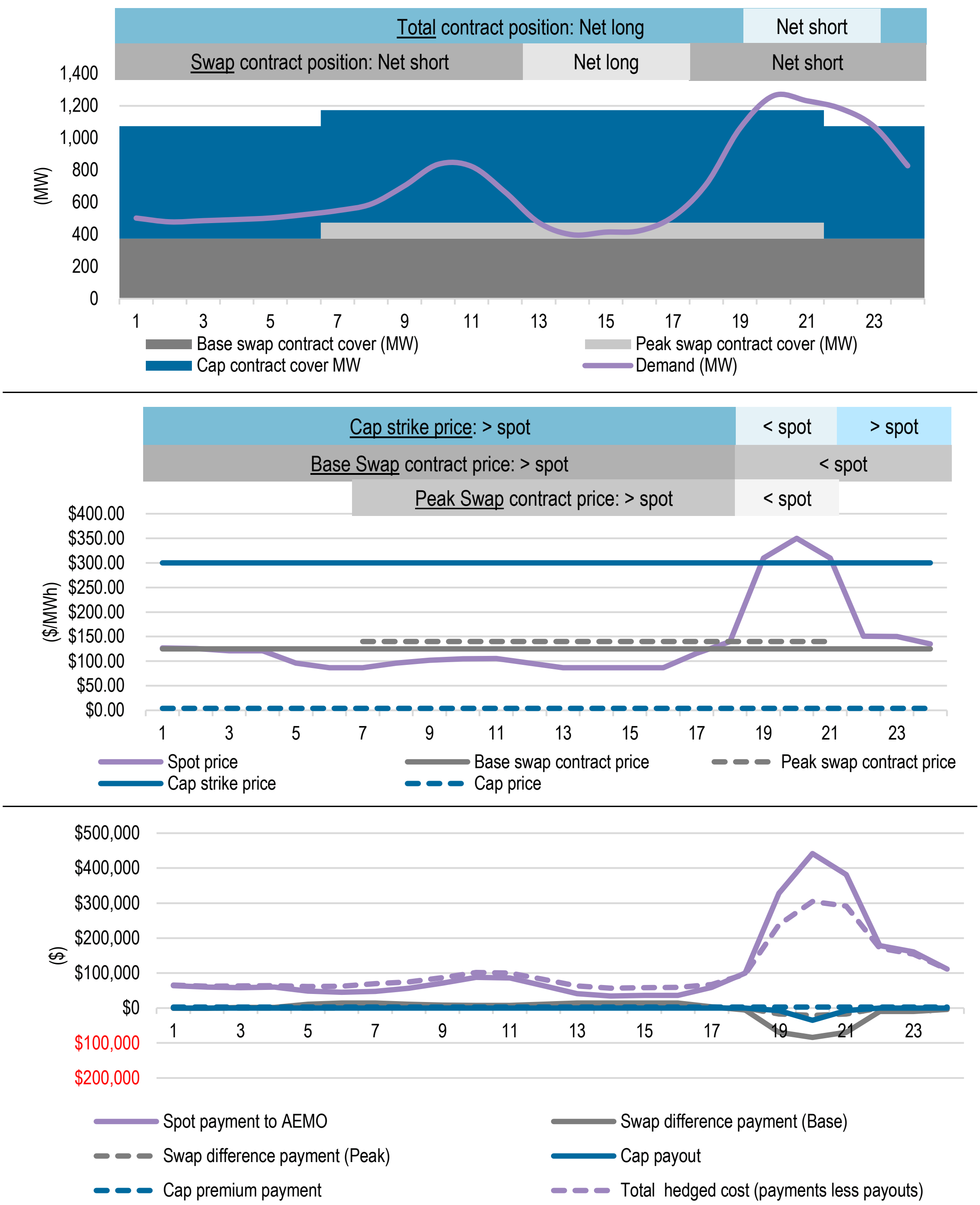
- Pays AEMO the spot price multiplied by the demand.
- Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract 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) and controlled load profiles (CLPs) - 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.

The NSLP is used as the representative load profile for residential and small business customers because the majority of residential and small business customers in New South Wales, Queensland, and South Australia, are on accumulation (or basic) meters. And those customers with digital (or interval) meters are in the minority. Therefore, a single WEC is estimated for residential and small business customers within each distribution zone.

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	CLP	CLOADNSWCE,ENERGYAUST	MSATS
	Ausgrid	CLP	CLOADNSWEA,ENERGYAUST	MSATS
	Endeavour Energy (Endeavour)	NSLP	NSLP,INTEGRAL	MSATS
	Endeavour	CLP	CLOADNSWIE,INTEGRAL	MSATS
	Essential Energy (Essential)	NSLP	NSLP,COUNTRYENERGY	MSATS
	Essential	CLP	CLOADNSWCE,COUNTRYENERGY	MSATS
Queensland	NA	System Load	QLD1	MMS
	Energex	NSLP	NSLP,ENERGEX	MSATS
	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

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]. To date 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 no doubt higher 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 continue to use the NSLP data in our estimation of the WEC. However, we recommend that future determinations use a combination of the NSLP and interval meter data in the 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.

[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.

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. Given the nature of AEMO's procedure for constructing the NSLP, the profile includes rooftop PV exports to the grid. Inclusion of exports in the NSLP is not counter to the purpose of the determination given that retailers a 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. ACIL Allen understands that prior to the introduction of five-minute settlement (5MS) in October 2021, interval meter load data is available on a net 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. Although the interval meter data includes rooftop PV exports, this will gradually be unwound over the next few determinations as the methodology uses more recent post-5MS data; and in any case the data at this stage represents the load profiles of about 30 per cent of residential and small business customers.

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 51 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 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 561 (i.e. 51 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 561 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 Final Determination, and consistent with the Final Determination of DMO 4, 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/peak/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 neutral scenarios from the latest available Electricity Statement of Opportunities

[2] When testing the different strategies, we do not run the full set of 561 simulations as this is time prohibitive. However, we run the full set of 561 simulations once the strategy has been chosen.

(ESOO) published by AEMO and take into account past trends and relationships between the NSLPs 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 three years are obtained. The profiles are adjusted by 'adding' back the estimated rooftop PV generation for the system demand and each NSLP (based on the amount of rooftop PV in each distribution network).
— A stochastic demand model is used to develop about 51 weather influenced simulations of hourly demand traces for the NSLPs, 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 51 years of weather data and uses a matching algorithm to produce 51 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.
— The set of 51 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 51 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 51 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 the corresponding regional demand from the past four years is developed to measure the change in NSLP as a function of the change in regional demand. This relationship is then applied to produce 51 simulations of weather related NSLP 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 across the 51 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 and NSLPs.

Date range of actual demand data used in the analysis

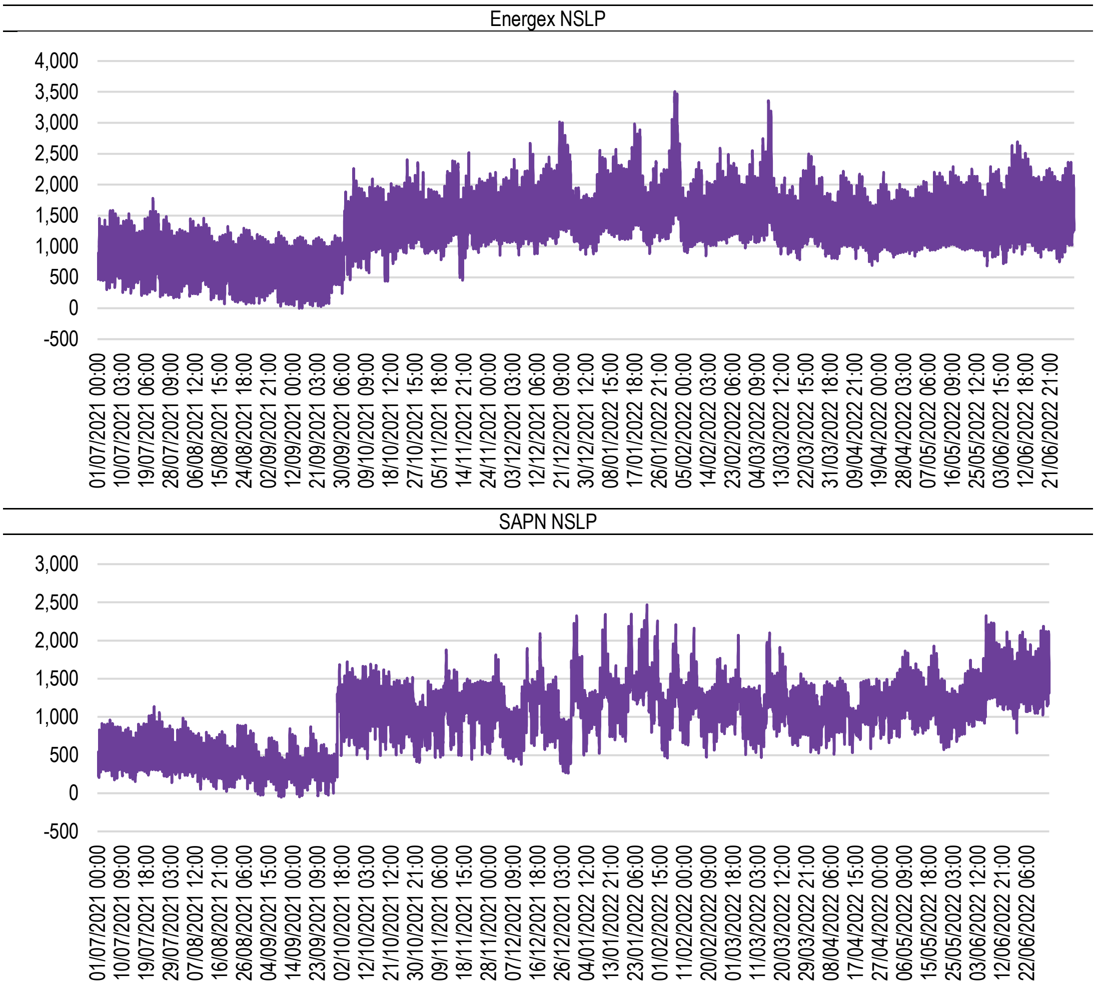
As noted above, the methodology usually uses the most recent past three years of actual demand data. For the 2023-24 determination this would mean using load data from the 2019-20 to 2021-22 financial years. With the introduction of 5MS in October 2021, ACIL Allen noted a long delay in the release of the NSLP data by AEMO, with the data released only in December 2022. Upon analysis of the data, we noted the step change in the Energex NSLP load coinciding with 5MS (as shown in Figure 2.3). We also noted a step change in the NSLP of South Australia with 5MS. A change could not be detected for the New South Wales NSLPs.

ACIL Allen had the opportunity to discuss this matter with AEMO. However, the reasoning given seemed quite complex and partly related to the treatment of rooftop PV, which meant there was no readily available way to transform the pre-5MS data so that it was compatible with the post-5MS data. For example, it could not be determined if the pre-5MS data required an uplift by a constant to better match with the post-5MS data, or whether it required a constant and a range adjustment. We note that the NSLP of South Australia appears to have experienced a change in range as well as an uplift.

Certainly, Figure 2.4 shows the average time of day shape of the NSLPs have changed with the commencement of 5MS, which is not easily explainable.

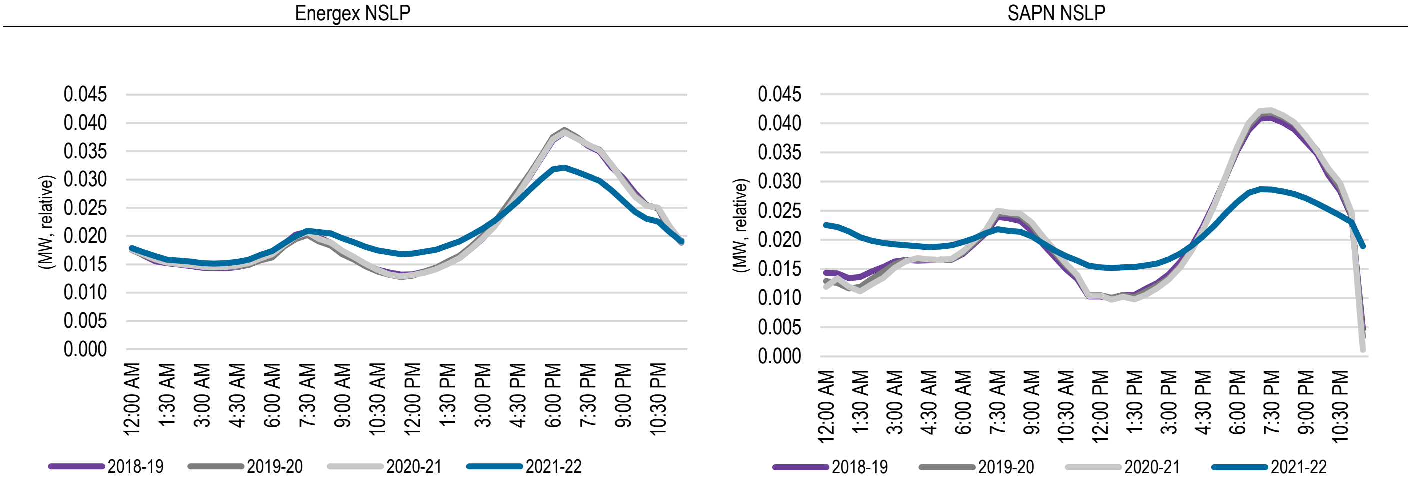
Given this step change, we have used the 2018-19 to 2020-21 demand data set as the starting input for the 2023-24 determination (this is the same demand data set used for the 2022-23 determination), rather than use the 2021-22 data. Although it is not ideal to use the older data set, we are of the view that doing so introduces far less error than adopting the newer data. Regardless of the underlying demand data set used, it should be recalled that the methodology scales the data set to the demand forecast parameters of 2023-24 and adjusts it for the forecast of rooftop PV for 2023-24 (rather than simply using the same scaled demand data set from the 2022-23 determination).

Figure 2.3 Energex NSLP (MW) – 2021-22



Source: ACIL Allen analysis of AEMO data

Figure 2.4 Average time of day demand (MW, relative) – Energex and SAPN NSLP



Source: ACIL Allen analysis of AEMO data

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. As a starting point for this analysis, for 2023-24 we use our March 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 2023-24 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 Reference case assumptions relevant for 2023-24

<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 2023-24.
— 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 2022 ESOO Central scenario (energy and peak demand)
— Aluminium smelters are assumed to remain operational.
— To reflect a higher rate of NEM-wide electrification the Reference case includes annual electrification demand from AEMO’s 2022 ISP Strong Electrification scenario</td><td>Rooftop PV
ACIL Allen’s in-house model of Rooftop PV uptake:
— NEM-wide Rooftop PV uptake is about 20 per cent higher than AEMO’s Central forecast by 2030.</td><td>Behind-the-meter BESS
ACIL Allen’s in-house model of behind-the-meter BESS uptake (linked to rooftop PV model):
— Higher NEM-wide uptake relative to AEMO Central forecast, about 38 per cent higher by 2050.</td><td>Electric vehicles
— AEMO’s 2022 ISP Strong Electrification scenario
— ACIL Allen’s charging profiles: a blend of three charging behaviours which changes over time as charging infrastructure is developed. Includes an overnight charging profile, a daytime charging profile and a late evening/convenience charging profile.</td></tr>
</table>

State based schemes	**NSW** NSW Roadmap capacity of: — 12 GW renewables by 2032 within designated REZ — 2 GW pumped hydro by 2030 — The Reference case assumes the Roadmap capacity is added to the market in approximately a straight-line over the period from 2023 through 2032.	**QLD** Queensland Energy and Jobs Plan (QEJP): — QRET target of 50% renewable energy generation by 2028 — 70% renewable energy generation by 2032 — 80% renewable energy generation by 2035 — 7 GW of long duration storage by 2035 — However, we assume the capacity required to satisfy the plan is deployed post 2023-24.	**TAS** TRET – 15,750 GWh (150 per cent) of renewable energy by 2030 and 21,000 GWh (200 per cent) by 2040 – However, we assume the capacity required to satisfy the plan is deployed post 2023-24.	**VIC** VRET targets of 40 per cent by 2025, 50 per cent by 2030 and 95 per cent by 2035. In the Reference case, it is assumed the additional VRET2 renewable capacity is committed and enters the market by 2025. About 500 MW of storage by 2024
Electricity supply (beyond new supply driven by state based schemes)	**Committed projects** — Named new entrant projects are included in the modelling where there is a high degree of certainty that these will go	**Assumed new entry and closures** Committed or likely committed generator closures included where the closure has been announced by the participant **(Liddell in 2023).**		

	ahead (i.e., project has reached financial close)		
Gas prices into gas-fired power stations	For 2023-24, it is assumed that gas prices are capped at $12/GJ as part of the Government's response to high electricity prices. However, the Reference case 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 and hence are exempt from the price cap. **Further discussion on the treatment of gas and coal price caps in the spot price simulations is provided in section 3.2** .		
Coal prices into coal-fired power stations	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 2023-24, domestic coal prices are capped at AUD$125/tonne as part of the Government's response to high electricity prices. **Further discussion on the treatment of gas and coal price caps in the spot price simulations is provided in section 3.2**.		
Interconnectors	**Existing interconnection** Assumed transfer capabilities updated to reflect recent history and known constraints (e.g., related to planned outages as part of upgrade works).	**ISP committed and actionable projects included**: — QNI minor (July 2023) — VNI Minor (Sep 2022)	**Victoria's System Integrity Protection Scheme** The Big Battery is included as a 300 MW/450 MWh battery since 1 October 2021 (increases the VNI import limit by 250 MW in summer at peak times).
Marginal loss factors	ACIL Allen's projections of average annual marginal loss factors (MLF) by generator DUID, developed using commercial power flow software.		
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 2.3 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	Avonlie Solar Farm	Solar	190	Q3 2023
2	NSW1	Bango Wind Farm (extension)	Wind	85	Q3 2023
3	NSW1	Capital Battery	Battery	100	Q2 2023
4	NSW1	Crookwell 3 WF	Wind	58	Q1 2023
5	NSW1	Hunter Power Project	Natural gas	660	Q4 2023
6	NSW1	Riverina Energy Storage System Discharge	Battery	100	Q1 2023
7	NSW1	Rye Park WF	Wind	396	Q1 2024
8	NSW1	Tallawara B Power Station	Natural gas	316	Q4 2023
9	NSW1	West Wyalong Solar Farm	Solar	90	Q1 2023
10	NSW1	Flyers Creek	Wind	145	Q1 2024
11	QLD1	Bouldercombe Battery	Battery	50	Q2 2023
12	QLD1	Clarke Creek WF	Wind	450	Q3 2023
13	QLD1	Dulacca WF	Wind	180	Q1 2023
14	QLD1	Edenvale Solar Park	Solar	146	Q1 2023
15	QLD1	Kaban WF	Wind	157	Q1 2023
16	QLD1	Kidston Storage Hydro	Pumped Hydro	250	Q3 2024
17	QLD1	Macintyre Wind Farm	Wind	923	Q1 2023
18	QLD1	Wambo Wind Farm	Wind	250	Q1 2024
19	QLD1	Karara Wind Farm	Wind	103	Q1 2024
20	SA1	Cultana Solar Farm	Solar	280	Q2 2023
21	SA1	Goyder South WF	Wind	100	Q3 2024
22	SA1	Torrens Island BESS	Battery	250	Q1 2023
23	NSW1	Riverina Solar Farm	Solar	40	Q2 2023
24	NSW1	Wollar Solar Farm	Solar	280	Q4 2023
25	NSW1	Wellington North Solar Farm	Solar	300	Q3 2024
26	SA1	Tailem Bend Stage 2 Solar Project	Solar	87	Q3 2023
27	SA1	Goyder South WF	Wind	412	Q3 2024
28	QLD1	Wandoan South Solar Stage 1	Solar	125	Q2 2023
29	VIC1	Wunghnu Solar Farm	Solar	80	Q3 2024
30	NSW1	Waratah Super Battery	Battery	850	Q3 2025
31	NSW1	Stubbo Solar Farm	Solar	400	Q1 2024
32	QLD1	Tarong West Wind Farm	Wind	500	Q1 2026

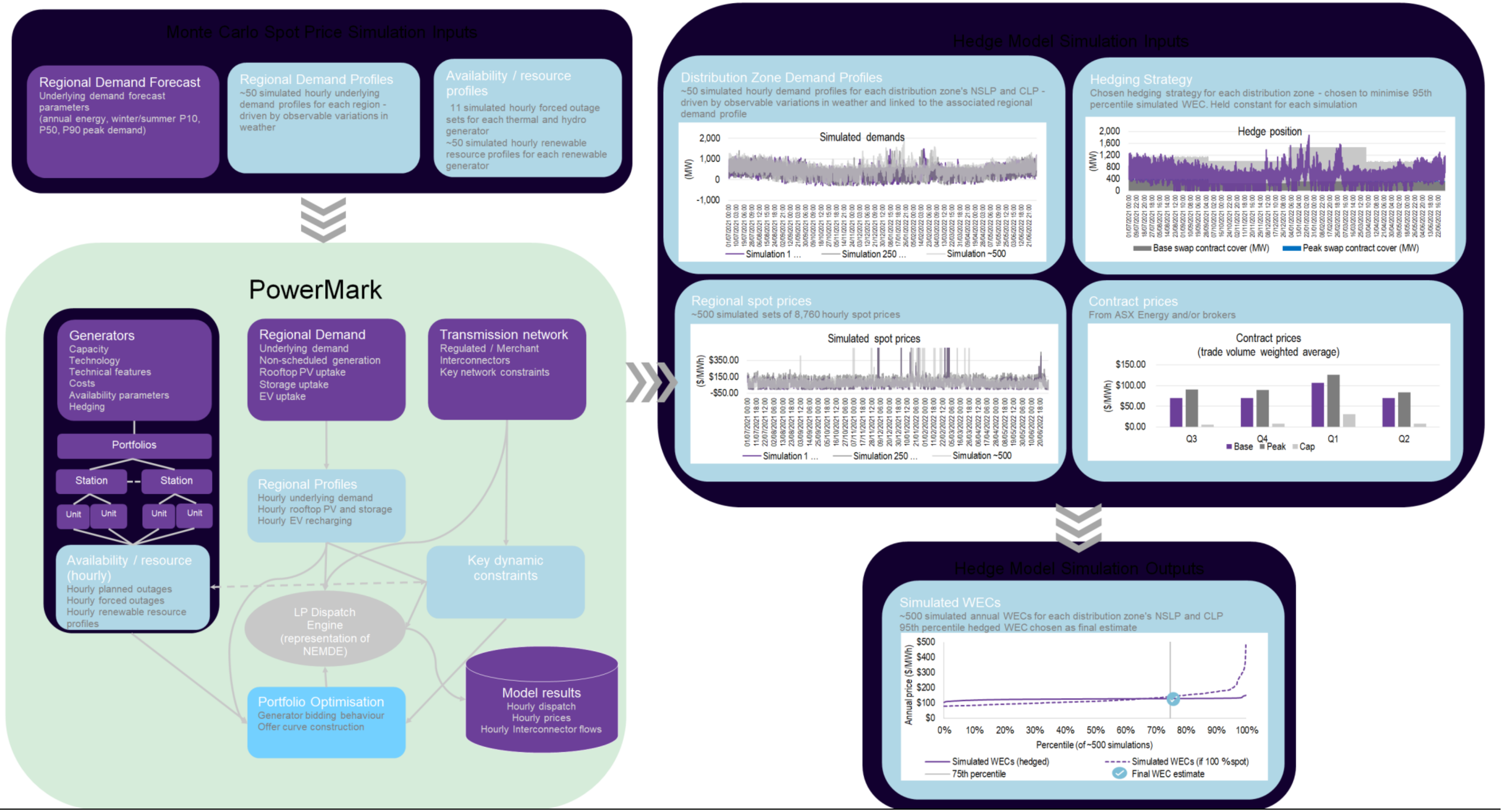
ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
33	SA1	Tailem Bend Battery Project	Battery	51	Q3 2023
34	NSW1	Broken Hill Battery	Battery	50	Q3 2023
35	NSW1	Darlington Point Energy Storage System	Battery	25	Q2 2023
36	NSW1	Riverina Energy Storage System 1	Battery	60	Q1 2023
37	NSW1	Riverina Energy Storage System 2	Battery	65	Q2 2023
38	VIC1	Kiamal Solar Farm Stage 2	Solar	150	Q1 2025
39	VIC1	Glenrowan Solar Farm	Solar	102	Q1 2024
40	VIC1	Derby Solar Farm	Solar	95	Q1 2024
41	VIC1	Fulham Solar Farm	Solar	80	Q1 2025
42	VIC1	Frasers Solar Farm	Solar	77	Q1 2024
43	VIC1	Horsham Solar Farm	Solar	118.8	Q1 2025
44	VIC1	Derby Battery	Battery	85	Q1 2025
45	VIC1	Fulham Battery	Battery	80	Q1 2025
46	VIC1	Kiamal Battery	Battery	150	Q1 2025
47	VIC1	Horsham Battery Discharge	Battery	50	Q1 2025
48	QLD1	Herries Range Wind Farm	Wind	1000	Q1 2027
49	VIC1	Golden Plains Wind Farm	Wind	756	Q1 2025

Source: ACIL Allen

Summary infographic of the approach to estimate the WEC

Figure 2.5 provides an illustrative infographic type summary of the data, inputs, and flow of the market-based approach to estimating the WEC.

Figure 2.5 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 2.6 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.

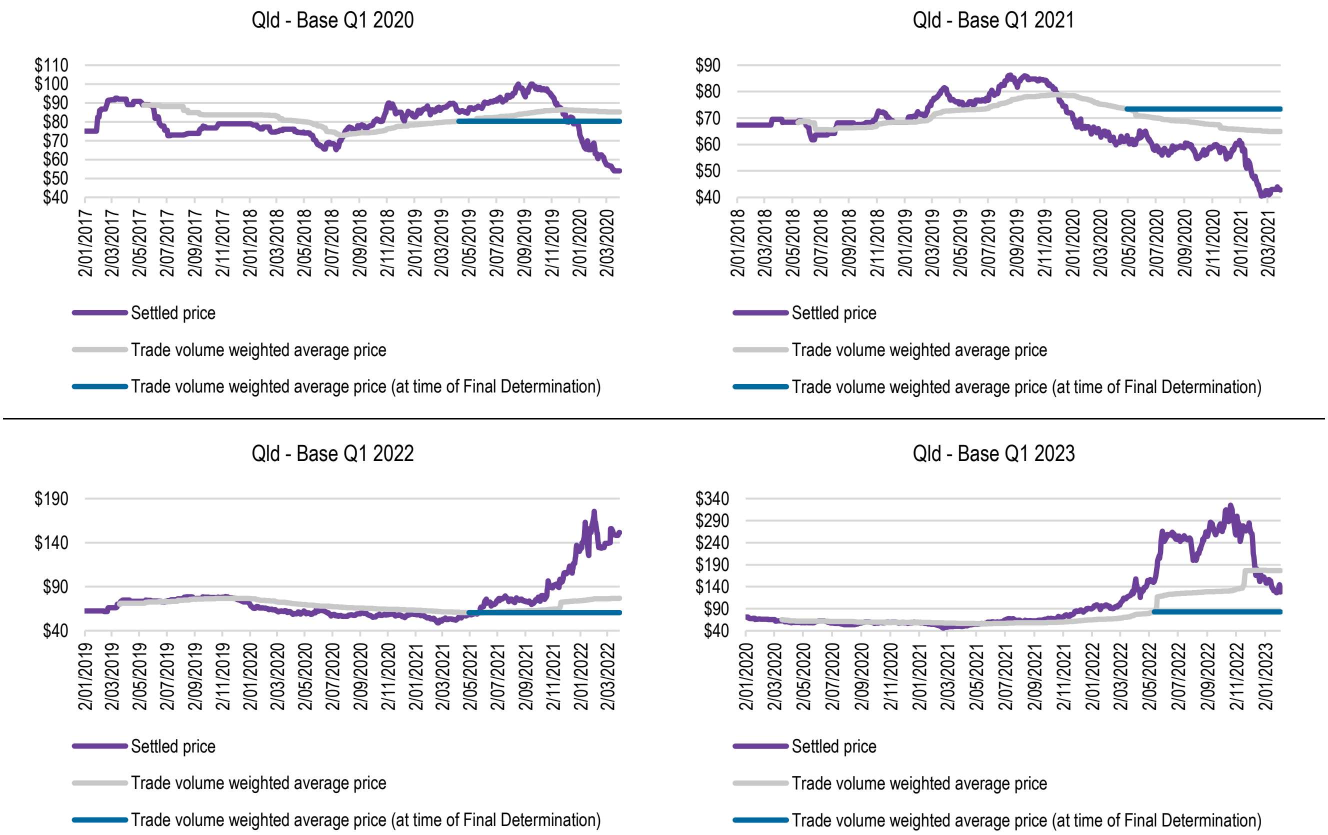
After the date the 2019-20 Final Determination was made, Q1 2020 traded prices increased slightly and then decreased slightly resulting in an actual trade weighted average price very similar to that used in the Final Determination. This is an example of a stable market price environment (at least in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

Figure 2.6 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 2.6 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.

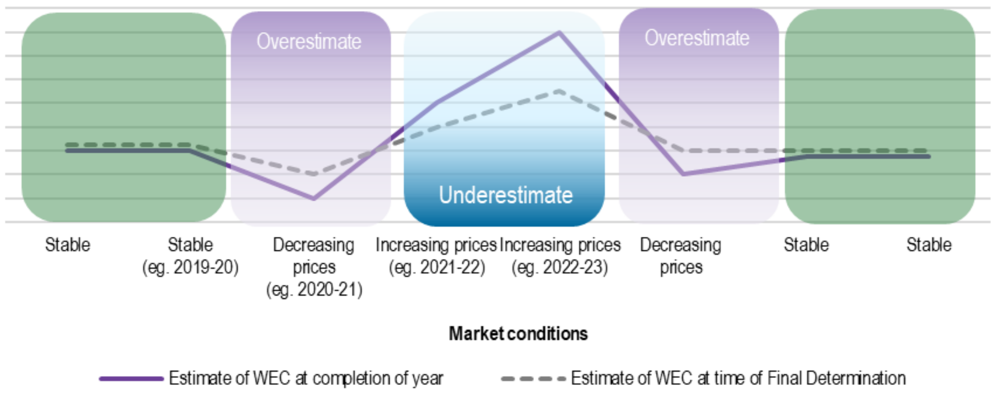
— The error in the WEC estimate, due to contract price variation, is likely to be greater in an environment of increasing prices, than it is in an environment of decreasing prices. This is because of the skewed nature of wholesale electricity prices in the NEM – prices can increase a lot more than they 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 2.7.

Figure 2.7 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 draft budget report was released in April 2023 and adopted 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 Final 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 South Australia Minister for Energy and Mining triggered the RRO in South Australia for the first quarter of 2024 on 7 January 2021. The AER also made a T-1 Reliability Instrument for South Australia from 8 January to 29 February 2024 inclusive, announced on 24 October 2022.

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[3].

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 Final 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[4], 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 this 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).

ACIL Allen has used AEMO's published estimates of the costs of the June 2022 events, as of 6 January 2023. For the more recently compensation amounts published by AEMC in March and April 2023, we have used AEMC's published compensation costs (in $ terms) and allocated 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 have been published prior to the 2023-24 Final Determination cut-off date of 10 May 2023 will be included in the 2023-24 Final Determination energy costs. Any outstanding

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

[4] 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 Draft 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 2023-24, ACIL Allen uses the following elements:

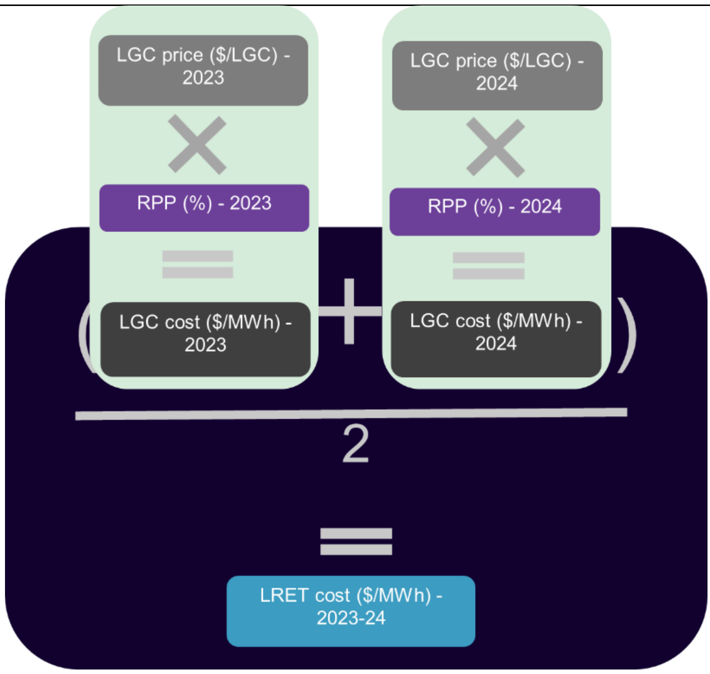
— The average of the trade-weighted average of LGC forward prices for 2023 and 2024 from brokers TFS

— the Renewable Power Percentage (RPP) for 2023, published by the CER

— the estimated Renewable Power Percentage (RPP) for 2024[5].

[5] The estimated RPP value for 2024 is estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2023 and 2024.

Figure 2.8 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 Percentages (STPs) for 2023 as published by the CER

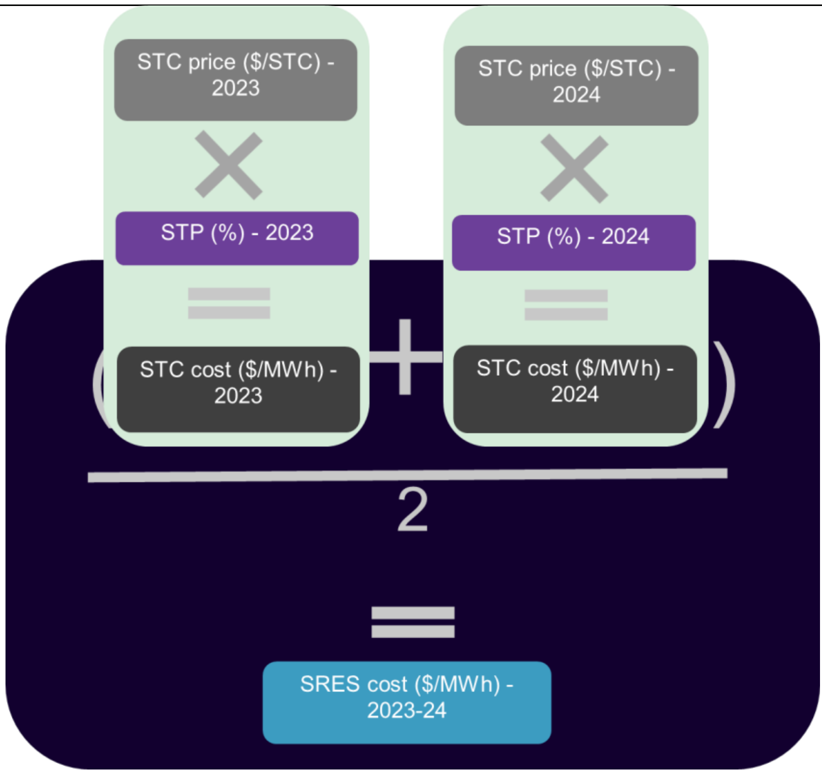
— an estimate of the STP value for 2024[6]

— CER clearing house price[7] for 2023 and 2024 for Small-scale Technology Certificates (STCs) of $40/MWh.

[6] The STP value for 2024 is estimated using estimates of STC creations and liable acquisitions in 2024, taking into consideration the CER's non-binding estimate.

[7] 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 2.9 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 2023 and 2024 of 9.5 and 10 per cent respectively, as published by IPART
- Historical Energy Savings Certificate (ESC) market forward prices for 2023 and 2024 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 2023-24 of one per cent, as published by the New South Wales and Department of Planning, Industry and Environment

— The post-tax penalty rate of $3.23/PRC. As PRC trade volume and price data becomes available we propose to estimate the PRC price as the trade volume weighted average price.

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 September 2021 final decision on the reporting requirements of REPS, notes it will report on costs of the scheme, which we use.

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[8], 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:

$$\textit{Price at load connection point} = \textit{RRN Price} * (\textit{MLF} * \textit{DLF})$$

The MLFs and DLFs used to estimate losses for the Final Determination for 2023-24 are based on the final 2023-24 MLFs and DLFs published by AEMO in March and April 2023 respectively.

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

Responses to submissions to Draft Determination 3

The AER forwarded to ACIL Allen a total of 17 submissions in response to its Draft Determination. 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:

— Wholesale spot simulations
— Use of the 95th percentile simulated WEC
— Load profiles
— Contract prices beyond the cut-off date
— Hedge book build up period
— Hedging strategy and contract instruments used in the hedge model
— Cap payouts
— Prudential costs
— June 2022 NEM events compensation cost recovery
— Price stability and accuracy
— AEMO fees.

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	Australian Energy Council	Yes	Yes	Nil	Nil	Nil	Nil
2	AGL	Yes	Yes	Nil	Nil	Nil	Nil
3	Alinta Energy	Yes	Nil	Nil	Nil	Nil	Nil
4	Energy Consumers Australia	Nil	Yes	Nil	Nil	Nil	Nil
5	Energy Locals	Yes	Yes	Nil	Nil	Yes	Nil
6	EnergyAustralia	Yes	Yes	Nil	Yes	Nil	Nil
7	GloBird Energy	Nil	Yes	Nil	Nil	Nil	Nil
8	Kevin Cox, Consumer Representative, Evoenergy Consumer Representative Council	Nil	Nil	Nil	Nil	Nil	Nil
9	Momentum Energy	Yes	Yes	Nil	Nil	Nil	Nil
10	Origin Energy (Origin)	Yes	Yes	Nil	Nil	Nil	Nil
11	Public Interest Advocacy Centre	Nil	Nil	Nil	Nil	Nil	Nil
12	Powershop	Yes	Yes	Nil	Nil	Nil	Nil
13	Red Energy and Lumo Energy	Yes	Nil	Nil	Nil	Nil	Nil

ID	Stakeholder	WEC	Hedge model	Environmental costs	NEM fees	Other costs	Energy losses
14	SA Department of Energy and Mining	Yes	Nil	Nil	Nil	Nil	Nil
15	SACOSS	Nil	Nil	Nil	Nil	Nil	Nil
16	Simply Energy	Yes	Nil	Nil	Nil	Nil	Nil
17	Sumo	Nil	Yes	Nil	Nil	Yes	Nil

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:

— AEC
— AGL
— Energy Consumers Australia
— Energy Locals
— EnergyAustralia
— Red Energy and Lumo Energy
— Simply Energy.

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

3.2 Wholesale spot price simulations

A number of submissions (including AEC, Origin, Red Lumo) noted that the spot price simulations for the Draft Determination were at a level lower than that of current price levels and the futures market. We are cognisant of this observation and its implications on the WEC estimates.

3.2.1 ACIL Allen response

We do not attempt to arbitrarily match our spot price modelling to the futures market but instead produce the spot price projections using underlying market fundamentals.

The implementation of the coal and gas price caps were in their infancy when the spot price simulations for the Draft Determination were undertaken. We noted in our report for the Draft Determination that at the point in time the spot market modelling was undertaken it was not immediately clear the extent of exemptions that may apply to the price caps – including purchases of gas from the short-term markets.

The market simulations for the Draft Determination assumed that the coal price cap would uniformly apply to all New South Wales and the Gladstone coal fired power stations (that is, those coal fired power stations exposed to the export coal market). The coal price cap is currently set at $125/t. This equates to broadly $60-70/MWh (after accounting for the heat content of the coal and the thermal efficiency of the power stations).

Similarly, the market simulations for the Draft Determination assumed that the gas price cap would apply uniformly to all gas fired power stations. The gas price cap is currently set at $12/GJ. This equates to broadly $80-100/MWh for a CCGT, and $140-160/MWh for peaking plant (after accounting for transport costs and the thermal efficiency of the power stations).

ACIL Allen has reviewed and updated its spot price simulations for the Final Determination. The key input assumption reviewed and changed in the updated simulations is the treatment of the coal and gas price caps, which is based on ACIL Allen's analysis of generator bidding behaviour since the implementation of the price caps, together with input from the AER.

The following assumptions changes were made within PowerMark for the Final Determination:

— All coal plant are assumed to have ready access to coal at prices capped at $125/t.

— All CCGTs are assumed to have ready access to gas at prices capped at $12/GJ.

— The other gas plant are assumed to base their offer curves on the cost of gas from the short term markets which the AER assumes to be $18/GJ.

In addition, we have taken into account the later return to service of Callide C.

The resulting simulated spot price outcomes for the Final Determination are about $10-25/MWh higher than those of the Draft Determination. This is a large increase, but given we are calculating a hedged price outcome, the update results in about a $2-$3/MWh increase for the various WECs compared with the Draft Determination.

3.3 Use of the 95th percentile simulated WEC

As with DMO 4 and the Draft Determination for 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 2.7 of outcomes in Queensland relative to the past four 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.

3.3.1 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 (and the Executive Summary) are the 75th percentiles of the simulated WECs.

3.4 Load profiles

As with submissions to the Issues Paper, a number of submissions (AEC, AGL, Alinta Energy, Red Lumo, Simply Energy) noted the importance of including the interval meter load data with the NSLP when estimating the WECs for DMO 5.

AGL on page three of its submission notes that based on its customer base, about 50 per cent of customers are on interval meters, much higher than the 30 per cent in all three DMO regions.

AGL on page four of its submission compares the average time of day load profile for the NSLP with the interval meter data and notes the NSLP profile is not as carved out during daylight hours as the interval meter profile, and this in turn would result in an underestimate of the WEC.

Energy Australia on page three of its submission supports the AER further investigating the load profiles in preparation for DMO 6.

Alinta on page two of its submission are of the view that including interval meter load data may improve the representativeness of the load profile used in the WEC estimation methodology.

3.4.1 ACIL Allen response

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

ACIL Allen is of the view that it will become increasingly apparent that it is more accurate to include the interval meter load data, than to exclude it, as the penetration of interval meters increases over the next few years. The risk is that customers on the NSLP will become the minority over the next few years. As noted by AGL, our estimate of 30 per cent penetration rate is for 2022. Although we do not have the half hourly data available to us, based on our other engagements with clients involving interval meters, we are aware of the strong rollout of interval meters over the past six or so months.

Further, the load profile of customers on interval meters is likely to be peakier since there is likely to a higher propensity for customers with existing rooftop PV to be moved to interval meters and hence away from the NSLP, ahead of non-solar customers; and of course, customers with new rooftop PV installation are likely to receive an interval meter. This was also noted by AGL on pages three and four of its submission.

However, we are of the view that the export component of the interval meter data be excluded.

We continue to suggest 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 (all other things equal), as well as reducing the risk of underestimating the value of the WEC. Using a combination of the NSLP and interval meter data, rather than just the interval meter data, allows for the natural transition of customers onto interval meters.

The AER has requested ACIL Allen to continue base the WEC estimates on the NSLP profiles for DMO 5.

3.5 Hedge book build up period

Energy Consumers Australia on page three of its submission appear to support a continuation of the current book build approach[9] – citing the importance of stability in WEC estimates.

[9] Energy Consumers Australia actually states its support for a shorter book build period – but given its reasoning of improved price stability we think this is typo.

Consistent with their responses to the Issues Paper, smaller retailers support the use of a shorter book build period.

Energy Locals on page two of its submission suggest that a two to three year hedging horizon is putting small, fast growing retailers at a disadvantage, stating that:

Our company has approximately tripled its direct customer base between Dec 2020 and Dec 2022 and continues to grow. This makes it virtually impossible to reliably forecast the level of hedges needed over a longer period. We believe that the 2–3-year time horizon limits opportunities for new retailers and hence stifles competition from innovative new entrants to the market.

GloBird Energy on page one of its submission states that a book build period of longer than 12 months is not appropriate as smaller retailers find it difficult to secure ASX Energy contracts beyond 12 months, whilst acknowledging that larger retailers may well enter into contracts two to three years in advance.

3.5.1 ACIL Allen response

In an environment of increasing prices, ACIL Allen agrees that hedging later in the price cycle puts a retailer at disadvantage compared with retailers that have hedged earlier in the cycle. However, that a retailer adopts such a strategy is independent of the DMO – that is, adopting such a strategy puts the retailer at a relative disadvantage regardless of the existence of the DMO since the retailer will still need to compete with other retailers when making retail offers to consumers.

ACIL Allen remains of the view that using all available trade data from ASX Energy to estimate contract prices is appropriate. We do not support attempting to cherry pick a date range for the contract data.

Finally, we do not impose a predetermined functional form for the hedge book build up (such as linear or exponential). Instead, we use the observable trade volumes as the weights to calculate the trade weighted average.

It is worth noting that about two thirds of the contract volume traded to date on ASX Energy for the DMO 5 period occurred within the past 12 months – 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.

3.6 Hedging strategy and contract instruments used in the hedge model

Retailers were generally in favour of continuing with the current hedge book approach of relying on ASX Energy price and volume data. Consumer advocacy stakeholders tended to be in favour of including other contract data if it better reflected the costs incurred by retailers and lowered the WEC.

3.6.1 Hedging strategy

The AEC on page two of its submission notes the higher reliance on caps in the hedging strategy adopted for DMO 5, which in turn represents a riskier strategy. The AEC states:

the DMO methodology should support an efficient prudent retailer's survival through extreme market conditions.

Origin on page four of its submission in noting the change in hedging strategy state that we should:

test the potential resilience of any strategy to different market outcomes (e.g. a material increase in spot prices) with a view to minimising risk, rather than simply adopting the least cost strategy based on a narrow range of modelled spot prices.

Origin then gives an illustrative example of the change in WEC for the Endeavor NSLP given the change in hedging strategy and spot price.

Powershop on page two of its submission states that retailers use a range of products and approaches to hedge their exposure to the market, rather than just the standard ASX Energy products. And suggest that smaller retailers may well adopt a strategy that is different to the larger incumbents. For example, smaller retailers may well make more use of load following contracts which attract a higher premium.

Sumo on page one of its submission questions the reliance solely on ASX Energy price data given that retailers are relying more on OTC contracts.

3.6.2 Smaller retailers being charge a premium to access ASX Energy contracts

Energy Locals on page one of their submission stated that the lower liquidity in the ASX Energy market makes it more difficult for smaller retailers to access ASX Energy contracts, and consequently:

this is driving retailers to the over-the-counter market where hedges are traded at a margin to the ASX.

3.6.3 Use of ASX Energy options

EnergyAustralia is generally in agreement with using ASX options when calculating the trade volume weighted price, but with some proposed changes:

— Attempt to remove speculative trades, based on the assertion that a reasonable portion of trades in options are speculative in nature rather than entered into by retailers.

— Inclusion of financial year options, as well as calendar year options for the WEC to be accurate.

Conversely, Momentum Energy on page one of its submission does not support the inclusion of options because it assumes retailers know in advance, which option strikes will end up being in-the-money and ignores the tendency for options to be brought simultaneously for the purpose of call spreads.

Momentum also suggests that including options increases the complexity of the methodology which increases the risk of participants attempting to estimate the WEC.

3.6.4 Implications of RRO

Powershop on page three of its submission notes that the hedging strategy adopted for the South Australia NSLP does not cover the peak load in **Figure 4.23** and therefore a retailer may be exposed to RRO compliance risk.

3.6.5 ACIL Allen response

Hedging strategy

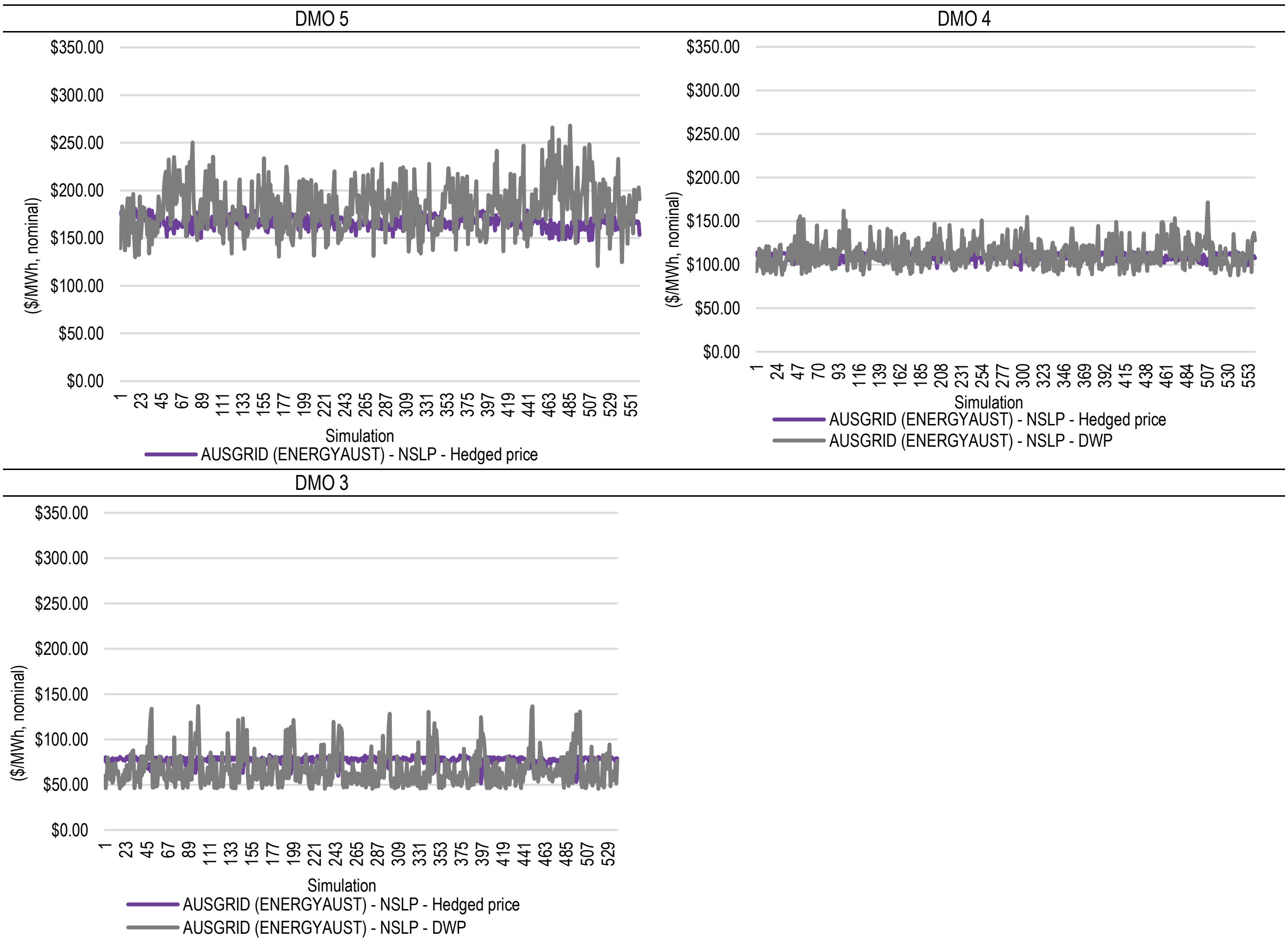
Each retailer will adopt its own strategy using a combination of ASX products, OTC hedges, direct hedges, and longer terms contracts. As noted in the methodology section 2.3.1, we are using the ASX contract data together with an assumed hedge book strategy based on ASX products only, as a proxy for the various hedging strategies used by retailers. Our methodology has not changed – we seek the strategy that minimises the 95th percentile WEC across the 561 simulations.

It is true that the strategy has changed slightly but this is a function of the changing nature of the load profiles, price profiles and relativity of the contract prices, not a change to the methodology.

There was a noticeable change in the weighting of cap contracts relative to base swap contracts in DMO 4. This was because it was apparent that peak contracts were no longer being routinely used (or traded). This meant that the peak contracts had to be replaced by more base swaps or caps (or a combination of the two) or an increased exposure to the spot market price. There are pros and cons as to which approach a retailer may take. Increasing the level of base swaps (and holding the cap cover level the same) may reduce the variability in the WEC but increases the overall WEC to a point that the retailer no longer remains competitive.

Using the Ausgrid NSLP as an example, despite the hedging strategy changing slightly from DMO 3 to DMO 4 to DMO 5, the resulting set of WEC outcomes within each DMO year displays a similar spread and is relatively stable compared with the option of being fully exposed to the spot market (as shown in **Figure 3.1**). This suggests that altering the hedging strategy has not increased the degree of variability in the set of WEC outcomes, despite the changing variability in spot price outcomes. Indeed, the spread of demand weighted spot price outcomes for the Ausgrid NSLP for DMO 5 is about $145/MWh, compared with a spread in the (hedged) WEC of about $35/MWh – demonstrating the resilience of the strategy across a wide range of spot price outcomes.

Figure 3.1 Annual hedged price and DWP ($/MWh, nominal) for NSLPs for the 561 simulations – 2023-24 and 2022-23 - Ausgrid

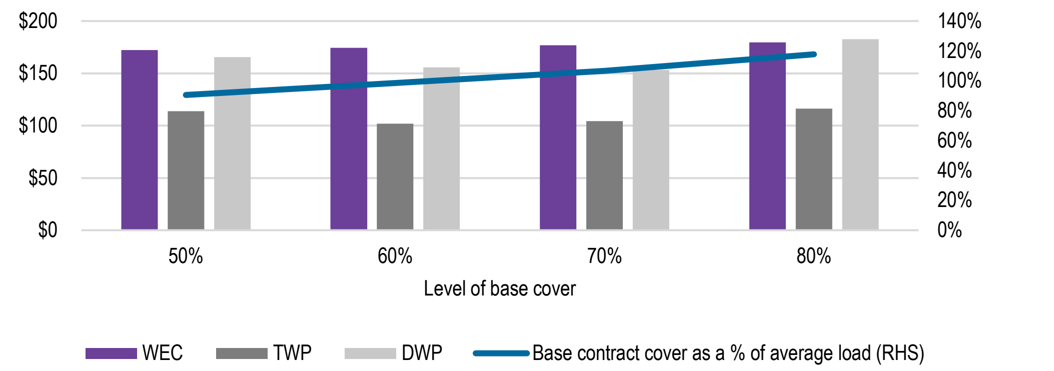


Source: ACIL Allen analysis

Origin uses the Endeavour NSLP as an example to demonstrate how the change in hedging strategy effects the extent the average load of the Endeavor NSLP is covered by base swaps, and the impact this has on the WEC for given changes in spot price. However, this assumes that the same simulation delivers the 75th percentile WEC under each hedging strategy. This is not the case - changing the hedging strategy does not necessarily result in the WEC of each simulation moving in the same direction by the same amount – there is an interplay between swap difference payments and cap payments. The chart in **Figure 3.2** shows the range in the 75th percentile WEC under a number of different base contact coverages is less than $7/MWh (or less than five per cent of the WEC for the Final Determination). The 75th percentile WEC does not come from the same simulation under the different hedging strategies. This relatively small change in WEC coincides with a range in TWP of about $15/MWh and in DWP of about $29/MWh for the simulations that give the 75th percentile WEC. This further demonstrates the robustness of the hedging strategy.

Therefore, we agree with Origin that there is some variation in WEC with a change in spot price outcomes and/or hedging strategy. However, we do not accept the suggestion that the hedging strategy ought to remain static from one DMO to the next. The change in shape of the load profiles and price outcomes surely gives retailers an incentive to adapt their hedging strategies over time.

Figure 3.2 75th percentile WEC ($/MWh, nominal) versus portion of load covered by base contracts - Endeavour



Source: ACIL Allen analysis using ASX Energy contracts up to 28 April 2023

Smaller retailers being charged a premium to access ASX Energy contracts

At this stage ACIL Allen has not been provided with sufficient evidence to respond to this matter in detail, and notes that the OTC data provided to the AER by retailers (and provided to ACIL Allen in summary form) did not suggest a price differential between OTC contracts and ASX Energy contracts. That said, ACIL Allen suggests the AER consider investigating the quantum of the premium paid by smaller retailers to access ASX Energy contracts for future determinations.

Use of ASX Energy options

In previous determinations, exercised ASX options were in effect included in the trade weighted average contract price. This is because ASX Energy report the exercised options as 'normal' futures contracts in their daily summary report on the day they were exercised. However, this meant the price attached to the exercised option was the daily settlement price on the day the option was exercised.

For this determination we have recommended that the methodology be refined to include the exercised call options at the trade weighted average strike price plus the trade weighted average premium attached to the exercised and expired call options. Put options have been excluded since they are rarely traded by retailers to hedge their retail load.

The inclusion of exercised options' strike prices and option premiums in this determination reflects the increasing use of options in the futures market over the past 12-18 months. To date, exercised base options contribute about 15 per cent of the traded volume of base 2023-24 contracts.

Although some stakeholders are not in favour of including options citing that the trade in options relates to speculators, the ACCC report shows that larger retailers certainly make use of options as part of their hedging strategy. Further, it could also be the case that some normal trades in contracts are also undertaken by speculators (although perhaps less likely), and these are not removed from the trade weighted average.

Although the traded weighted average contract price excludes financial year options, given that these are typically exercised after the contract data cut-off date for the Final Determination, we do not see this as a valid reason to exclude calendar year options. This is analogous to having a different data cut-off date for each quarterly contract product – so that the data cut-off for each product is the same amount of time before the commencement of the quarter. For example, the data cut-off date for the Final Determination is 10 May 2023, this is 11 months before the commencement of the April 2024 quarter. Based on the suggestion of excluding the calendar year options, we should also exclude all trades within 11 months before the start of each quarter so that each quarter is treated equally.

We are not persuaded to exclude options on the basis that their inclusion makes the WEC less predictable for retailers. The variability in future prices over the past 12 months also makes the WEC less predictable - entering into a futures contract or option both have risks.

In summary, and as noted in many of our reports for previous determinations, by using ASX Energy contract data, the methodology is not explicitly assuming that retailers only hedge with using ASX Energy products. Rather, the methodology develops a simplified hedging strategy using transparent ASX Energy data to represent the costs of hedging. We are in effect pricing other contracts at the ASX trade weighted price.

Implications of RRO

The triggering of the RRO in South Australia has been taken into account in our analysis since the cap contract volume is set at 100 per cent of the median of the annual peak loads minus the base contract volume. The example profile in **Figure 4.23** is from a simulation that includes loads above the P50 peak and hence are not 100 per cent covered by hedge contracts.

3.7 Cap payouts

Origin on page 10 of its submission note that the cap payouts from our spot price modelling are higher than that of the trade weighted average cap price.

3.7.1 ACIL Allen response

Given the trade weighted average cap price is less than where cap prices are trading today it should not be surprising that the cap payouts from our spot price modelling are also higher than the trade weighted average.

3.8 Prudential costs

Energy Locals 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, this has resulted in prudential costs increasing broadly at the same rate (in percentage terms) as the WEC over the past four DMOs.

3.9 AEMO fees

EnergyAustralia on page three of its submission state that there is an error in our estimation of the fees associated with the Full Retail Contestability (FRC) and Energy Consumers Australia (ECA) components – suggesting we have applied the incorrect value and unit.

3.9.1 ACIL Allen response

As noted by EnergyAustralia, the FRC and ECA fees are expressed by AEMO in $/connection point/week terms. However, we require these fees to be expressed in $/MWh terms so they can be included as part of the TEC cost stack.

For this and all previous determinations, we convert these cost components to a $/MWh basis by accounting for the number of connection points, the number of weeks per year, and the annual consumption levels (all of which are provided in the AEMO budget and fees report). This explains why we arrive at a different, but correct, numerical value compared with the AEMO budget.

On this basis, no change in approach is required.

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 to date:

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

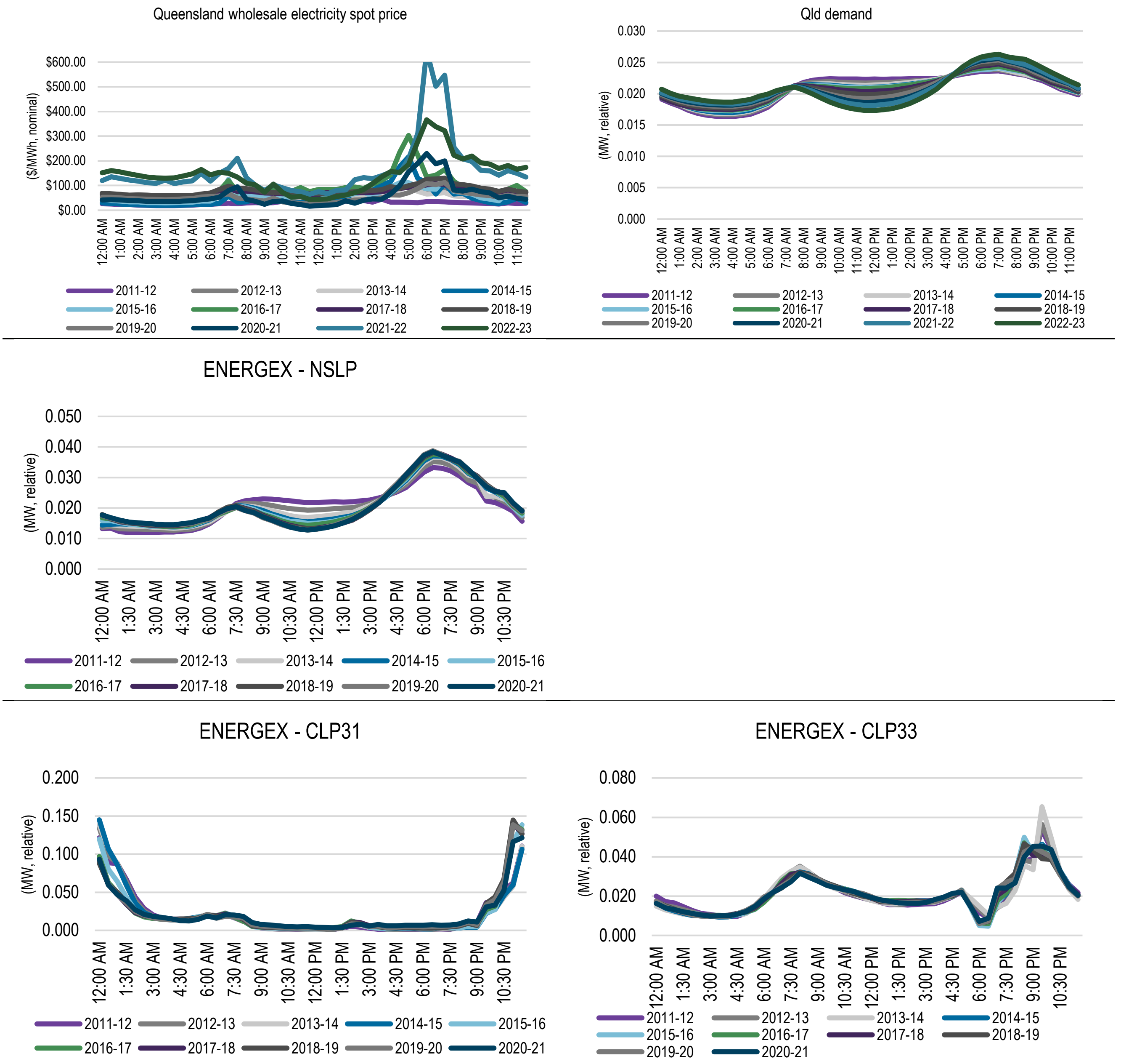
— LNG netback prices in the first quarter of 2022-23 continued to grow to a peak of about AUD$70/GJ in October 2022, and have since declined to about AUD$20/GJ.
— This has resulted in wholesale electricity prices averaging around $149/MWh, $137/MWh, and $118/MWh in Queensland, New South Wales and South Australia, respectively (for the period 1 July 2022 to 30 April 2023).
— We have seen some impacts of the Government's December 2022 intervention of capping coal and gas prices, on wholesale electricity spot prices.

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[10] (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, we recommend data be obtained from AEMO for residential and small business customers on interval meters, to account for the load profile of residential and small business customers on interval meters, which is likely to show the trend in carve out of demand during daylight hours has continued over the past few years.

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

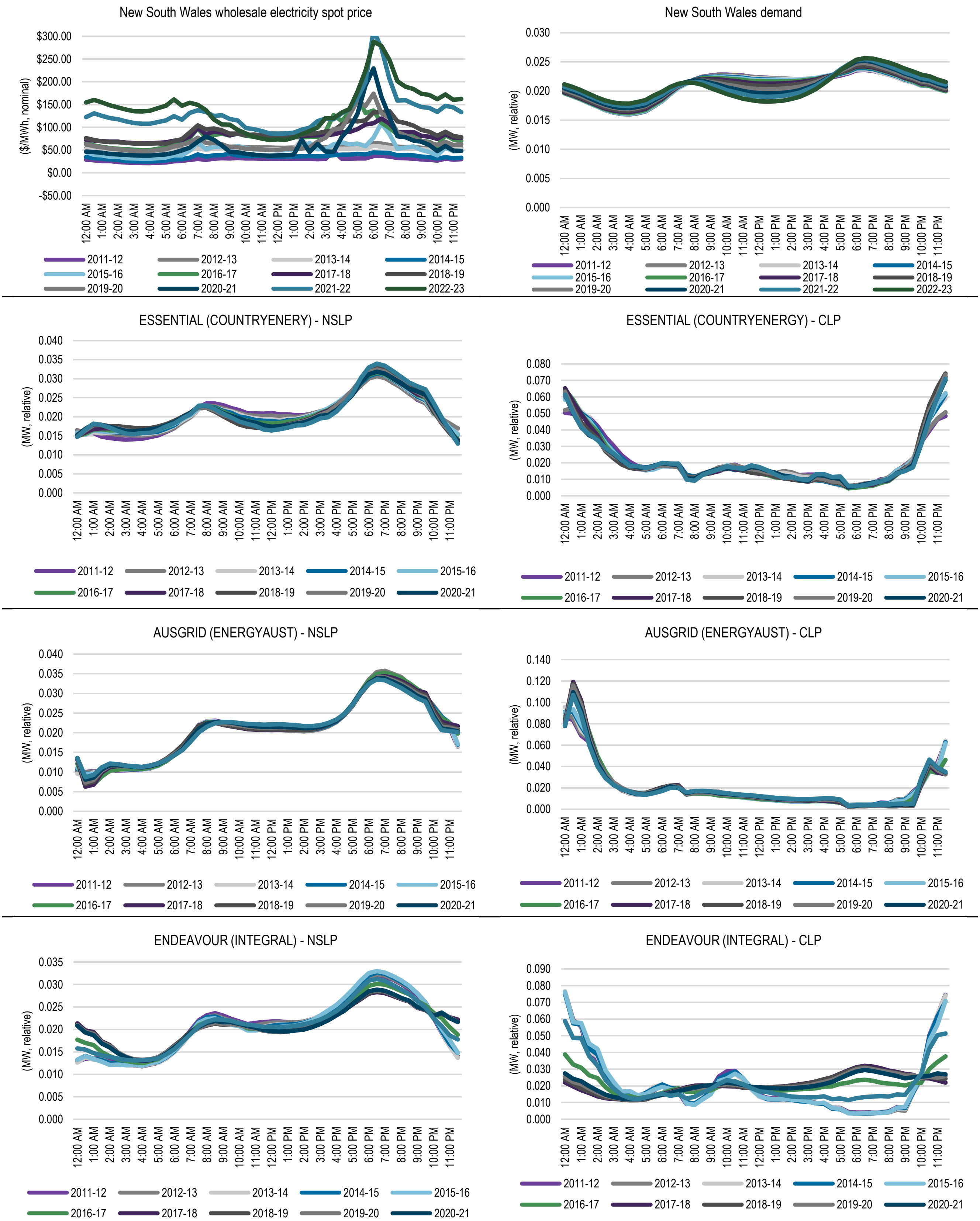
Figure 4.1 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2011-12 to 2022-23



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. 2022-23 price and regional demand series includes data up to April 2023. Insufficient or unresolved NSLP/CLP load data available for 2021-22 and 2022-23 and hence excluded.

Source: ACIL Allen analysis of AEMO data

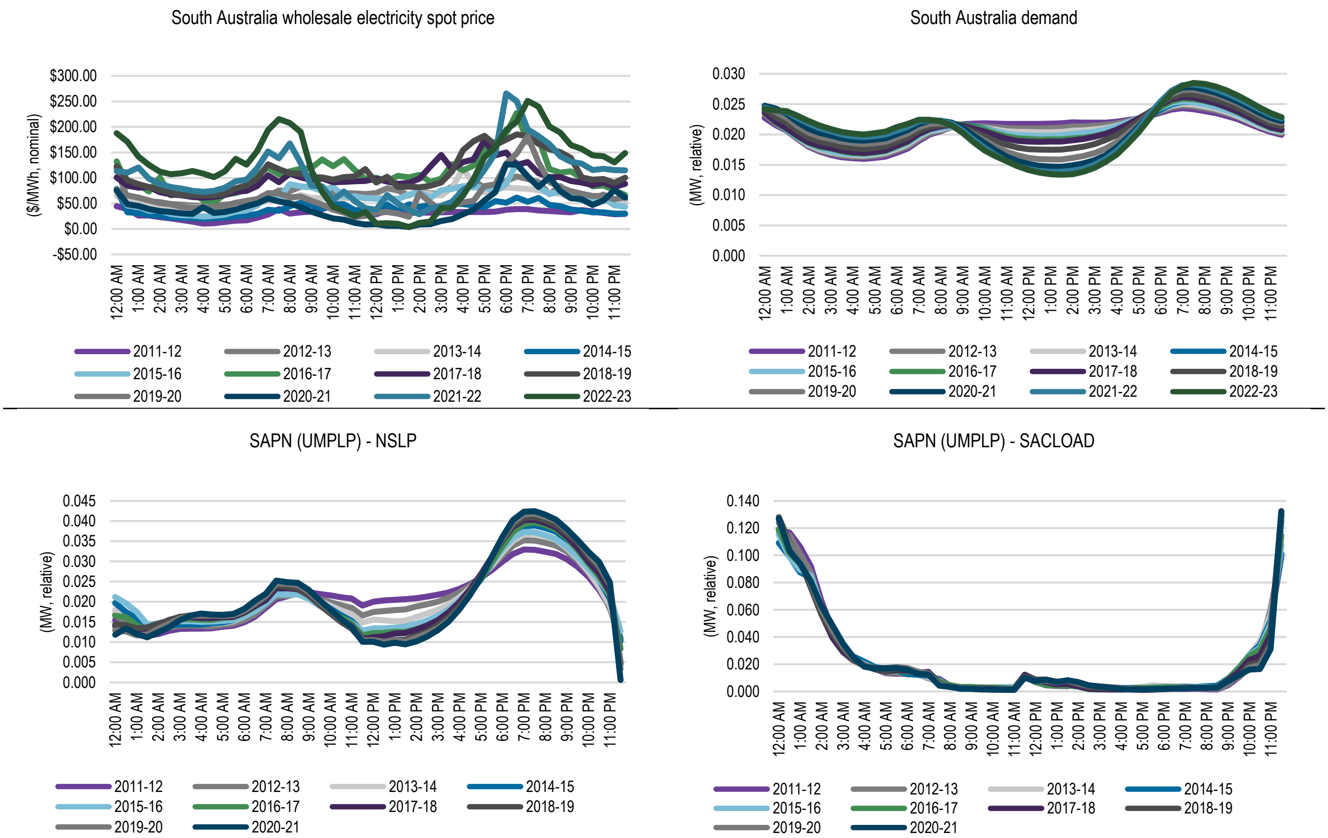
Figure 4.2 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – New South Wales – 2011-12 to 2022-23



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. 2022-23 price and regional demand series includes data up to April 2023. Insufficient or unresolved NSLP/CLP load data available for 2021-22 and 2022-23 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. 2022-23 price and regional demand series includes data up to April 2023. Insufficient or unresolved NSLP/CLP load data available for 2021-22 and 2022-23 and hence excluded.

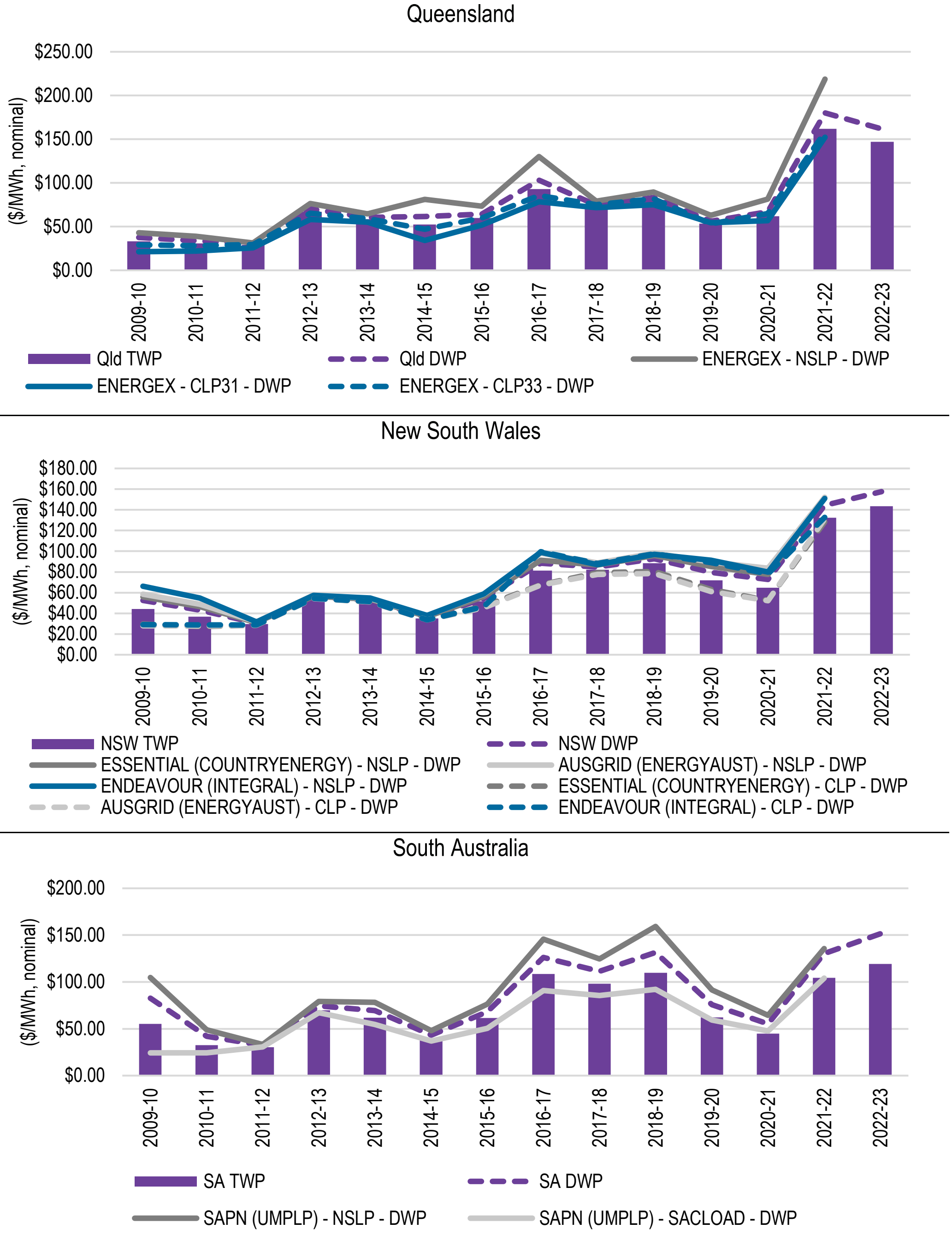
Source: ACIL Allen analysis of AEMO data

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.

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 2022-23



Note: Values reported are spot (or uncontracted) prices. 2022-23 price series includes data up to April 2023. Insufficient/unresolved NSLP data available for 2022-23.

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.

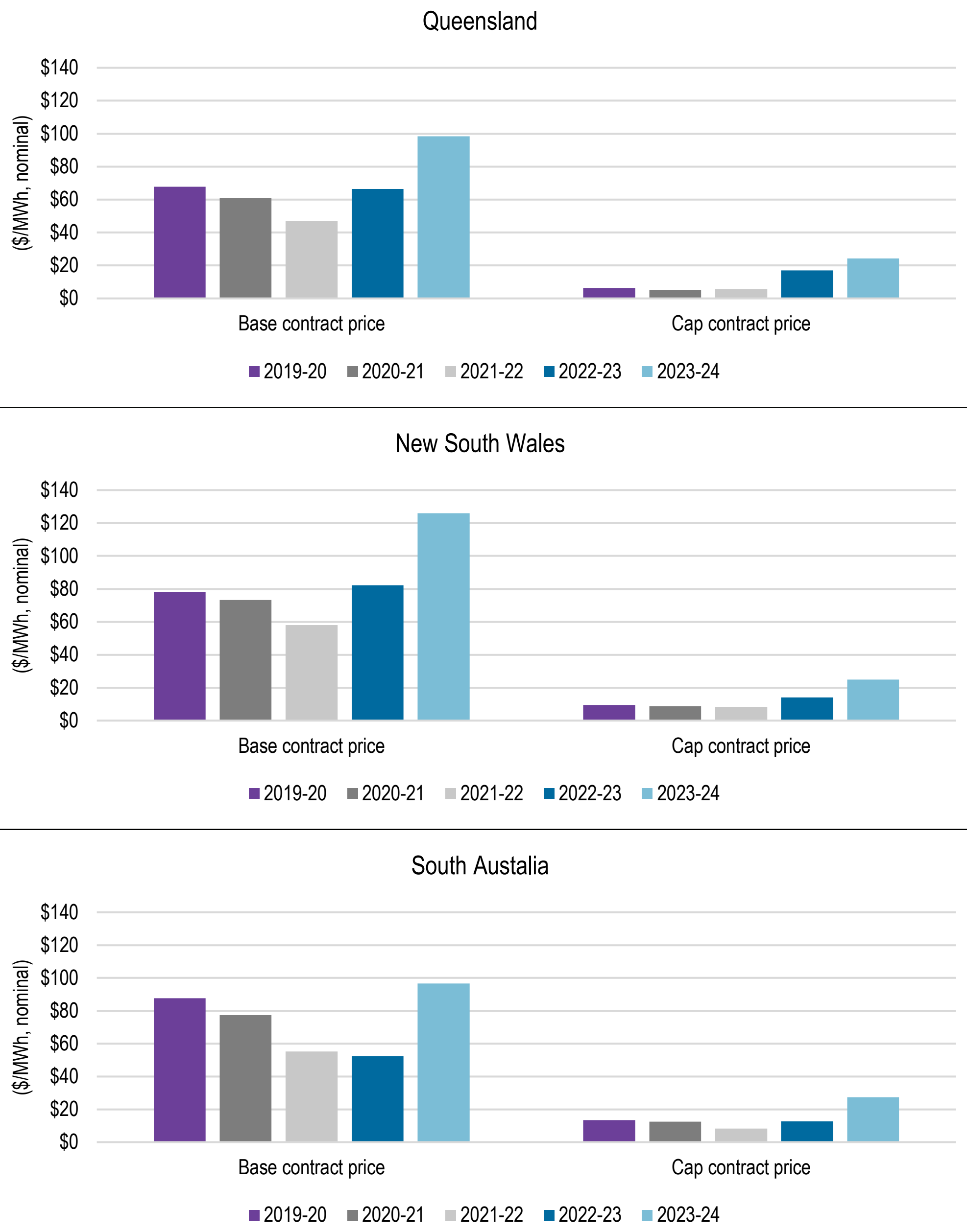
Compared with the 2022-23:

- Futures base contract prices for 2023-24, on an annualised and trade weighted basis to date, have:
  - increased by about $32.00/MWh for Queensland
  - increased by about $43.70/MWh for New South Wales
  - increased by about $44.30/MWh for South Australia.
- Cap contract prices for 2023-24 have increased noticeably compared with 2022-23, and on an annualised and trade weighted basis to date, have:
  - increased by about $7.20/MWh for Queensland
  - increased by about $10.90/MWh for New South Wales
  - increased by about $14.80/MWh for South Australia.

Unlike the three determinations spanning 2019-20 to 2021-22 in which there was a clear decline in contract prices, the market is clearly expecting the higher price outcomes experienced in 2022-23 to continue into 2023-24, due to the relatively stronger coal and gas costs, coupled with the closure of Liddell in New South Wales, and the delayed return of Callide C in Queensland, more than offsetting the amount of utility scale renewable investment coming on-line between 2022-23 and 2023-24. Although the Government's intervention on coal and gas prices has reduced the market's expectations on wholesale electricity wholesale spot prices for 2023-24, the trade weighted average futures prices remain elevated relative to 2022-23 since a large portion of hedges were purchased prior to the announcement of the Government's intervention.

The cost of hedging the NSLP load profile will be further exacerbated by the expected continued uptake of rooftop PV which carves out the demand during daylight hours, coupled with the commissioning of over 4,000 MW of utility scale solar, resulting in very low spot price outcomes during daylight hours, certainly less than the base contact price, making the already peaky NSLP demand profile more expensive to hedge.

Figure 4.5 Base, and Cap trade weighted average contract prices ($/MWh, nominal) – 2019-20 to 2023-24



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 2023-24 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 10 May 2023. 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 12-18 months. To date, exercised base options contribute about 15 per cent of the traded volume of base 2023-24 contracts.

Table 4.1 to Table 4.3 show the estimated quarterly base and cap contract prices for 2022-23 (Final Determination) and 2023-24. Base contract prices have increased from 2022-23 to 2023-24 by about 50 per cent in Queensland and New South Wales, and by about 80 per cent in South Australia. And there are very strong increases in cap prices across all quarters – averaging about 38 per cent in Queensland, nearly 80 per cent in New South Wales, and nearly 120 per cent in South Australia.

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

	Q3	Q4	Q1	Q2
2022-23				
Base	$60.01	$61.33	$82.97	$61.49
Cap	$14.04	$15.53	$29.81	$9.10
2023-24				
Base	$102.68	$90.29	$115.32	$85.40
Cap	$20.02	$22.05	$37.20	$17.88
Percentage change from 2022-23 to 2023-24				
Base	71%	47%	39%	39%
Cap	43%	42%	25%	96%

Source: ACIL Allen analysis using ASX Energy data

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

	Q3	Q4	Q1	Q2
2022-23				
Base	$77.89	$69.68	$94.22	$87.42
Cap	$9.88	$11.60	$24.22	$10.95
2023-24				
Base	$147.30	$107.90	$124.23	$124.23
Cap	$24.36	$22.51	$31.39	$21.80
Percentage change from 2022-23 to 2023-24				
Base	89%	55%	32%	42%
Cap	147%	94%	30%	99%

Source: ACIL Allen analysis using ASX Energy data

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

	Q3	Q4	Q1	Q2
2022-23				
Base	$50.41	$42.80	$64.66	$52.09
Cap	$4.97	$9.17	$30.92	$5.53
2023-24				
Base	$102.52	$64.32	$109.56	$110.82
Cap	$14.81	$13.98	$65.19	$16.15
Percentage change from 2022-23 to 2023-24				
Base	103%	50%	69%	113%
Cap	198%	52%	111%	192%

Source: ACIL Allen analysis using ASX Energy data

The following charts show daily settlement prices and trade volumes for 2023-24 ASX Energy quarterly base futures, peak futures and cap contracts up to 10 May 2023. It can be seen that the trading of these contracts tends to commence from mid to late 2020. That said, the volume of trades prior to 2021 is minimal, and the trades prior to 2022 represent 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.

The announcement of the Government intervention in the form of coal and gas price caps coincided with a decline in futures prices of between $50 and $100/MWh (depending on the quarterly product). However, given a large proportion 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 or increase slightly rather than decrease since the announcement.

For the majority of quarters and regions, the current contract price, although much lower than prior to the Government's intervention announcement, still remains slightly above the trade weighted average for the Draft Determination. This means that since there has been no further decline in daily contract prices between the Draft and Final Determination, the trade weighted average contract price for the Final Determination has not declined relative to that of the Draft Determination.

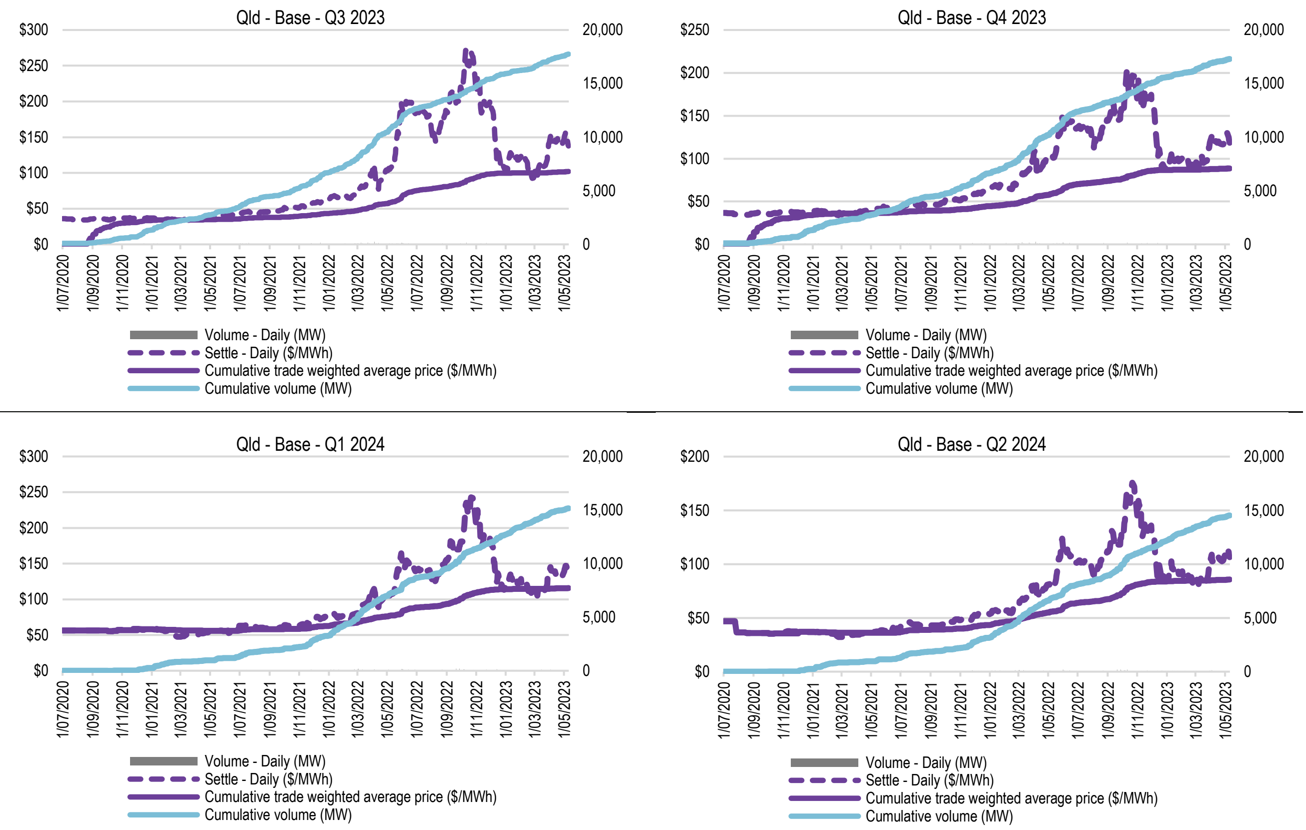
Indeed, contract prices have increased since the Draft Determination. This could be for several reasons, including:

— the further delay in return to service of Callide C

— a reassessment of the impact of the coal and gas price caps on wholesale electricity price outcomes now that there is a longer time series of observable market outcomes from the past four to five months.

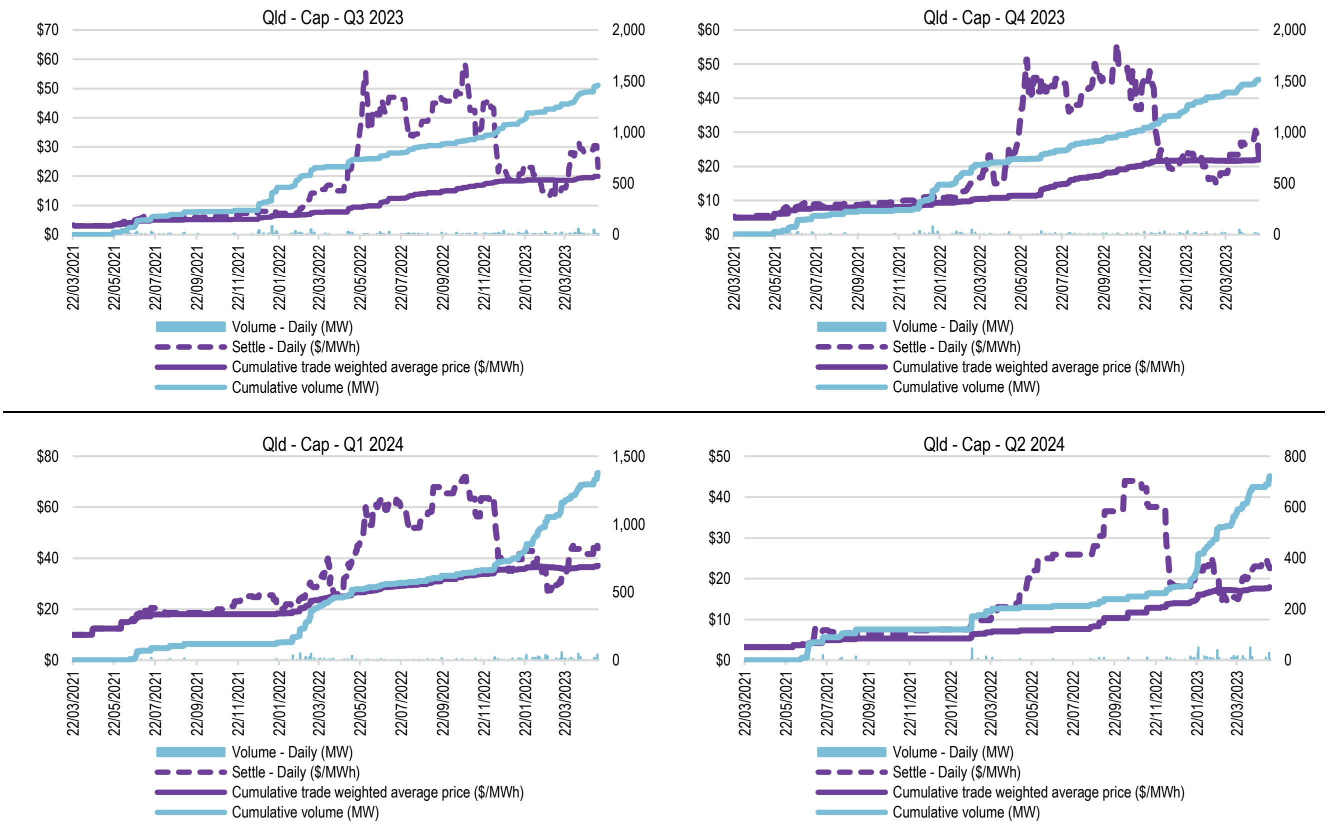
— the expectation of a return to El Nino in 2023-24 and its associated impact on extreme weather driven demand outcomes.

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



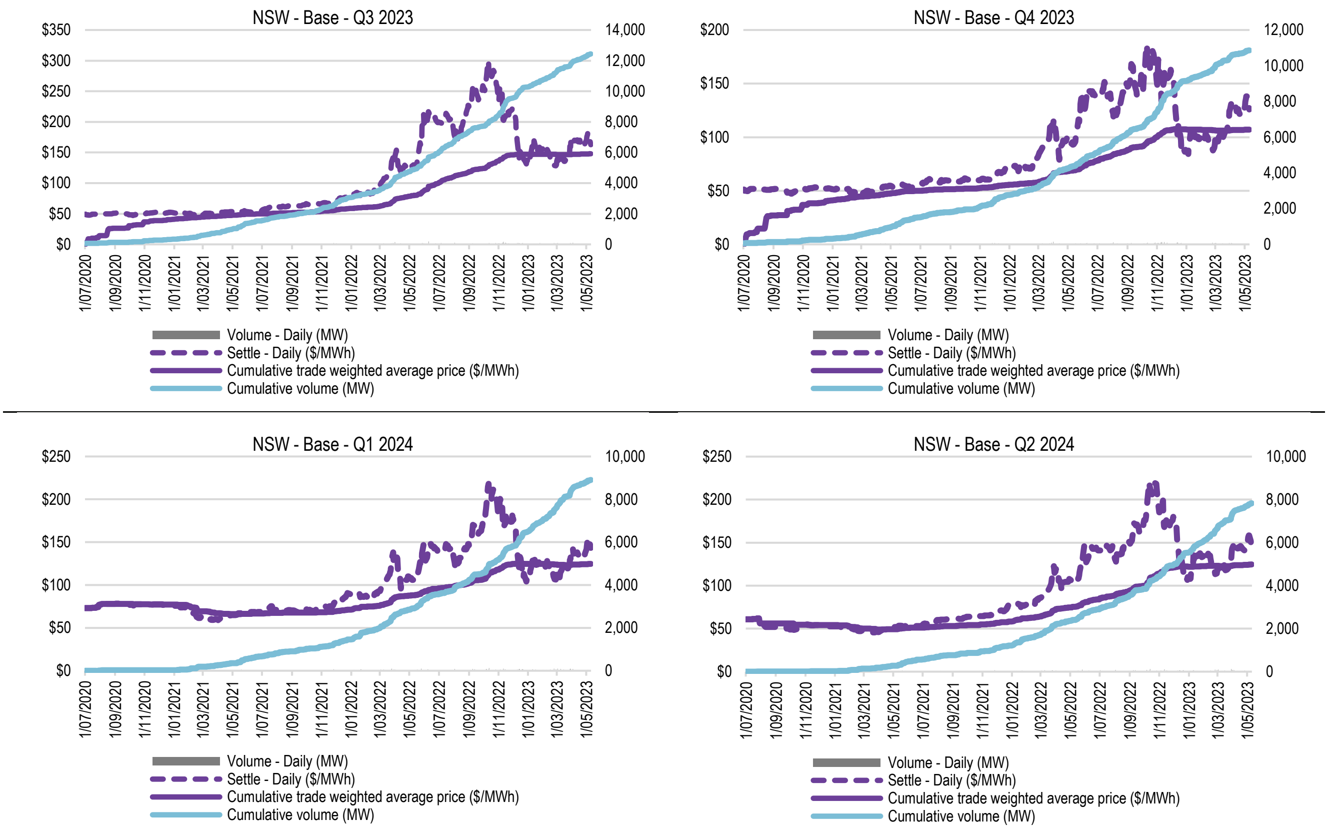
Source: ACIL Allen analysis using ASX Energy data

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



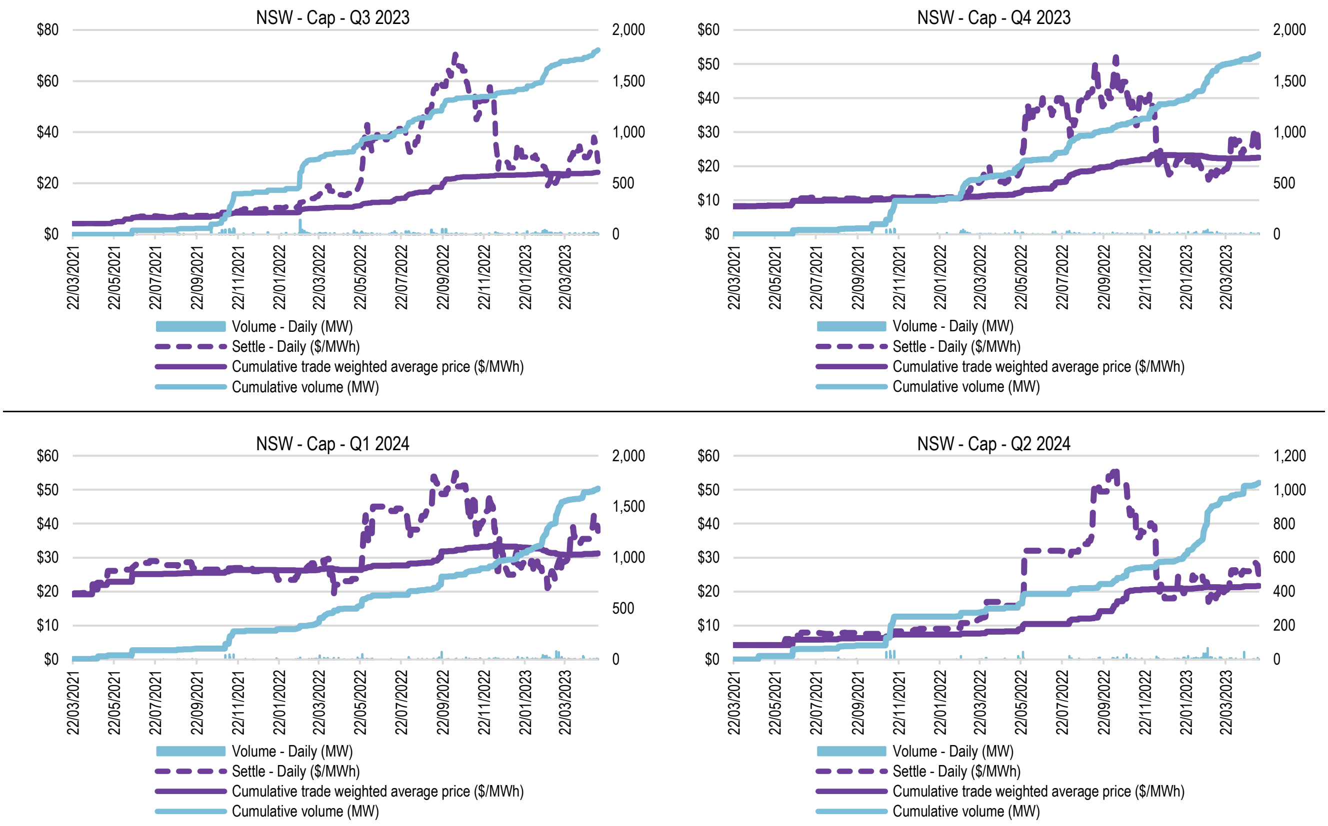
Source: ACIL Allen analysis using ASX Energy data

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



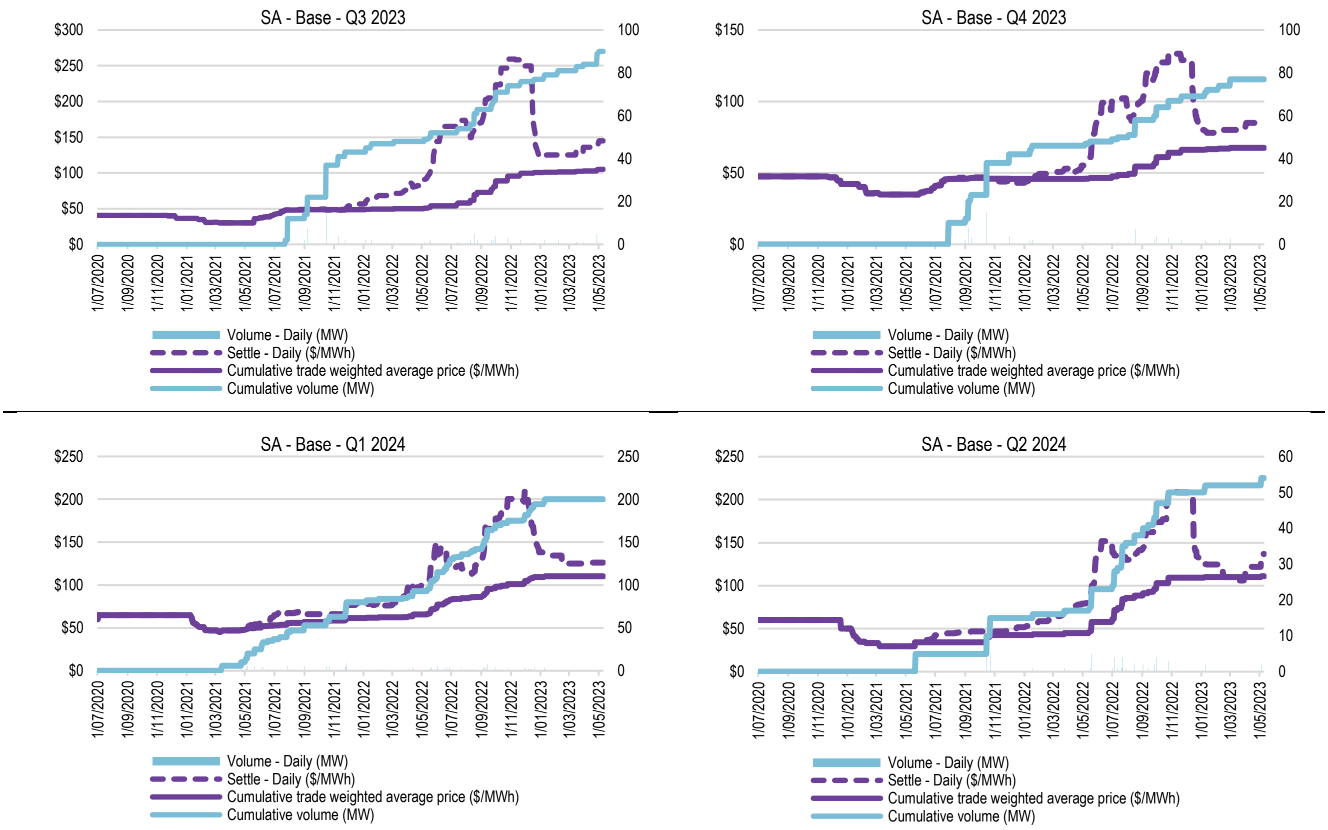
Source: ACIL Allen analysis using ASX Energy data

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



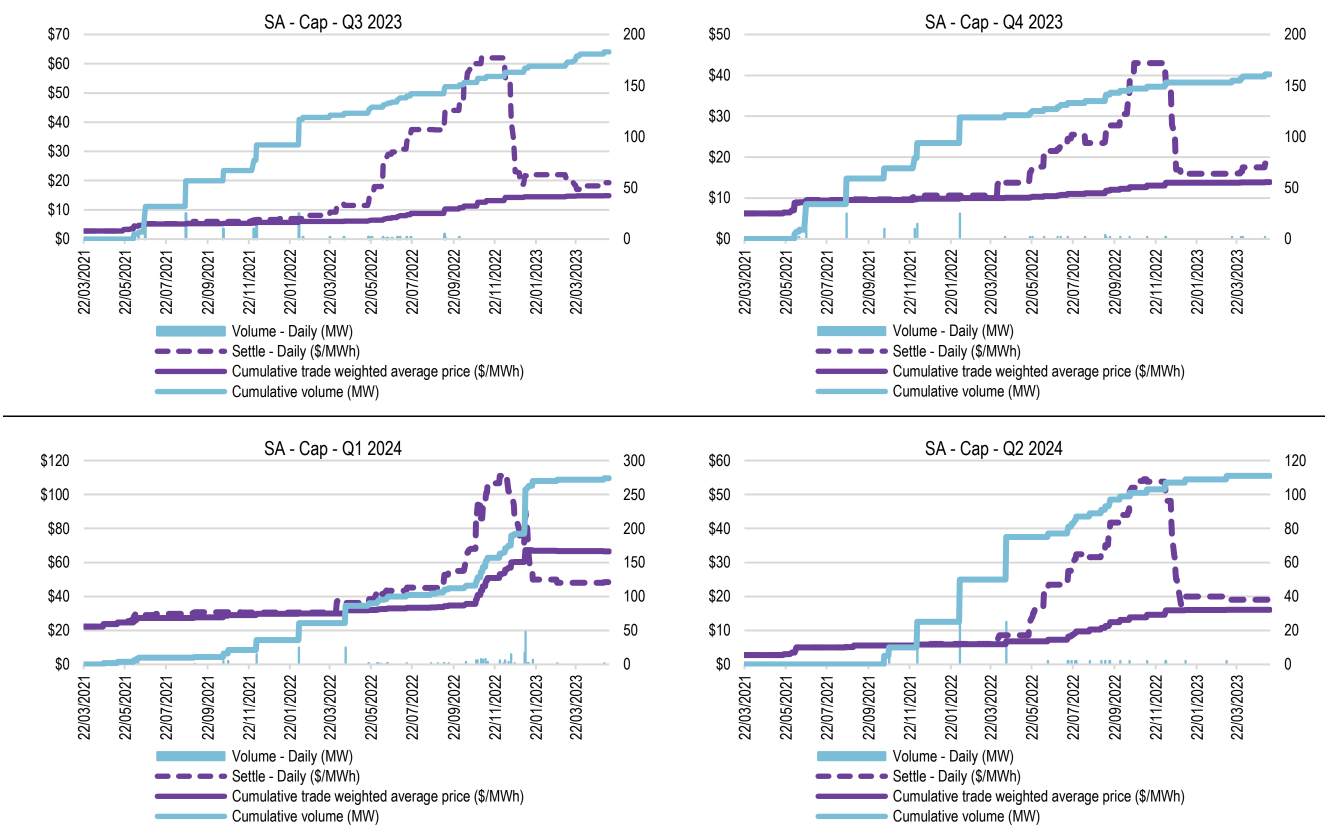
Source: ACIL Allen analysis using ASX Energy data

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

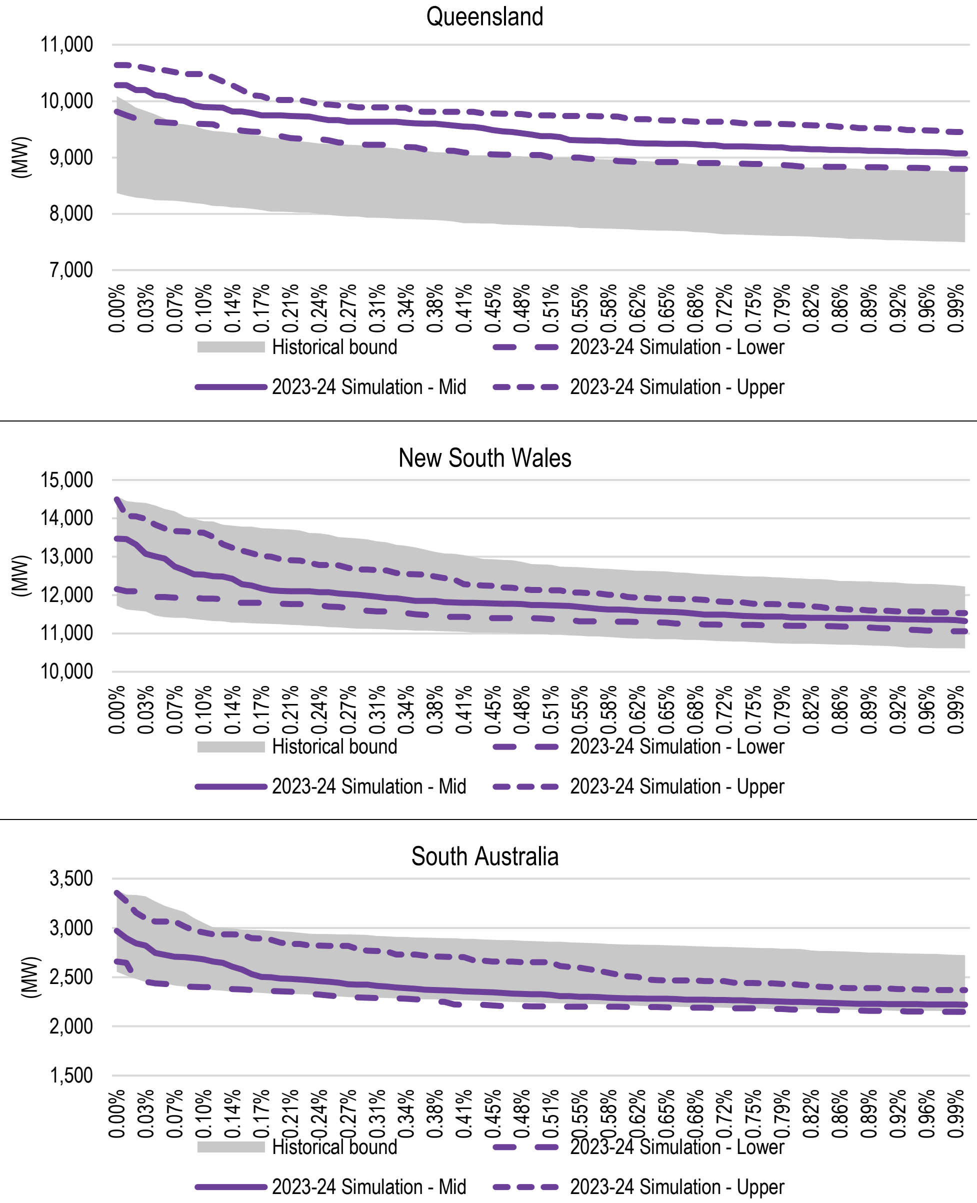
4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for the 561 simulations (51 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 2023-24, 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 51 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2023-24 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 2023-24 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. Conversely, the simulated demand sets for 2023-24 in South Australia are slightly lower than historic levels due to reductions in industrial load. Further, the demand forecast for 2023-24 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 2023-24 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 4.13 shows the range of the simulated NSLP demands envelope recent actual outcomes. This variation results in the annual load factor[11] of the 2023-24 simulated demand sets ranging between:

— 27 per cent and 35 per cent compared with a range of 29 per cent to 43 per cent for the actual Energex NSLP between 2009-10 and 2020-21 (as shown in Figure 4.14)

— 37 per cent and 43 per cent compared with a range of 41 per cent to 51 per cent for the actual Essential NSLP between 2009-10 and 2020-21

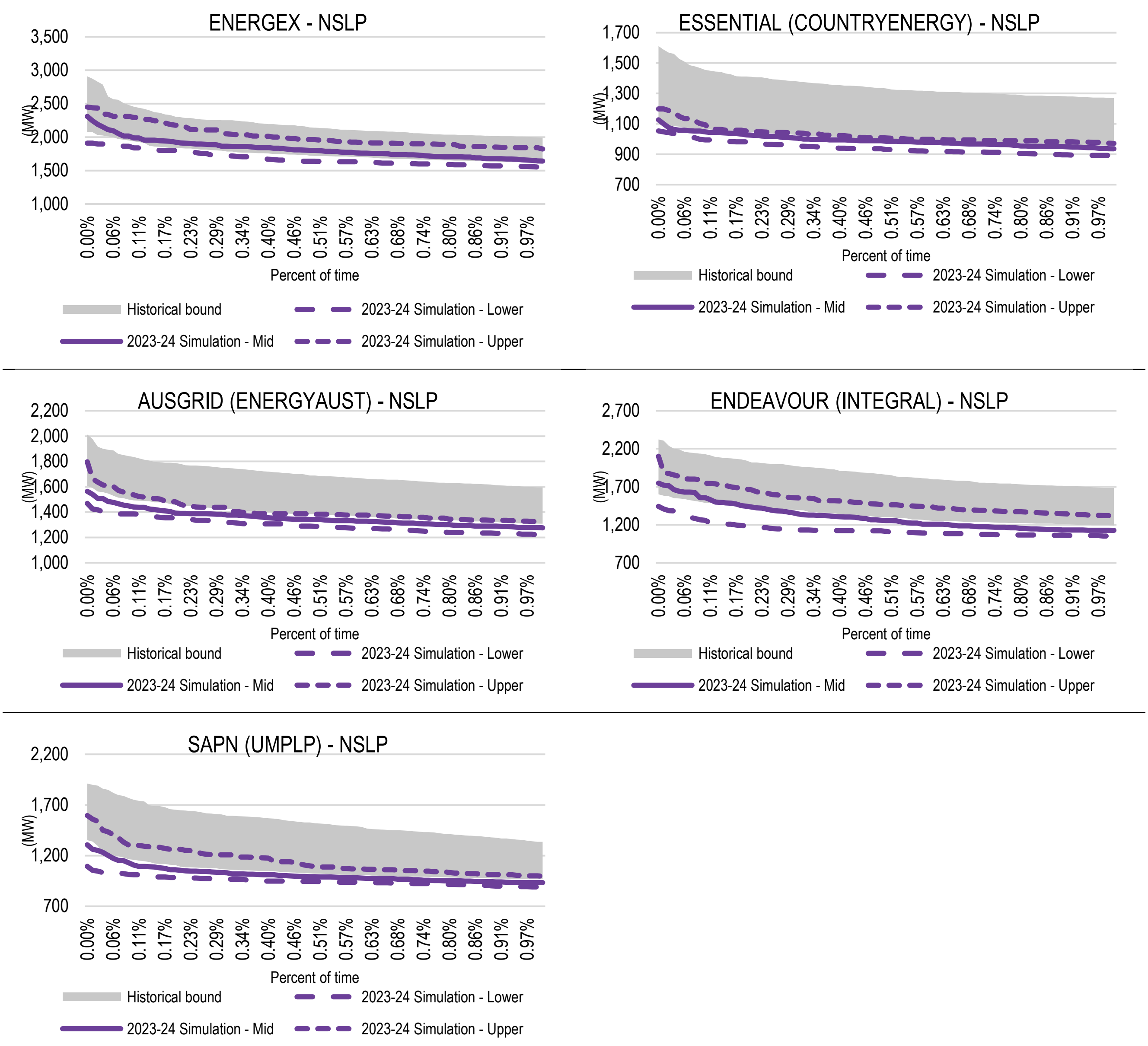
[11] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

- 27 per cent and 34 per cent compared with a range of 31 per cent to 36 per cent for the actual Ausgrid NSLP between 2009-10 and 2020-21
- 24 per cent and 34 per cent compared with a range of 31 per cent to 39 per cent for the actual Endeavour NSLP between 2009-10 and 2020-21
- 19 per cent and 28 per cent compared with a range of 21 per cent to 33 per cent for the actual SAPN NSLP between 2009-10 and 2020-21.

With the exception of the Endeavour and Ausgrid NSLPs, there has been an observable fall in the load factor in the actual NSLP between 2010-11 and 2017-18 due to an increase in penetration of rooftop solar PV panels. However, it is fair to say this reduction has slowed in the past couple of years – which may well be related to recent rooftop PV installations being associated with meter upgrades (from accumulation to interval meters) or changes in demand patterns due to COVID-19 restrictions.

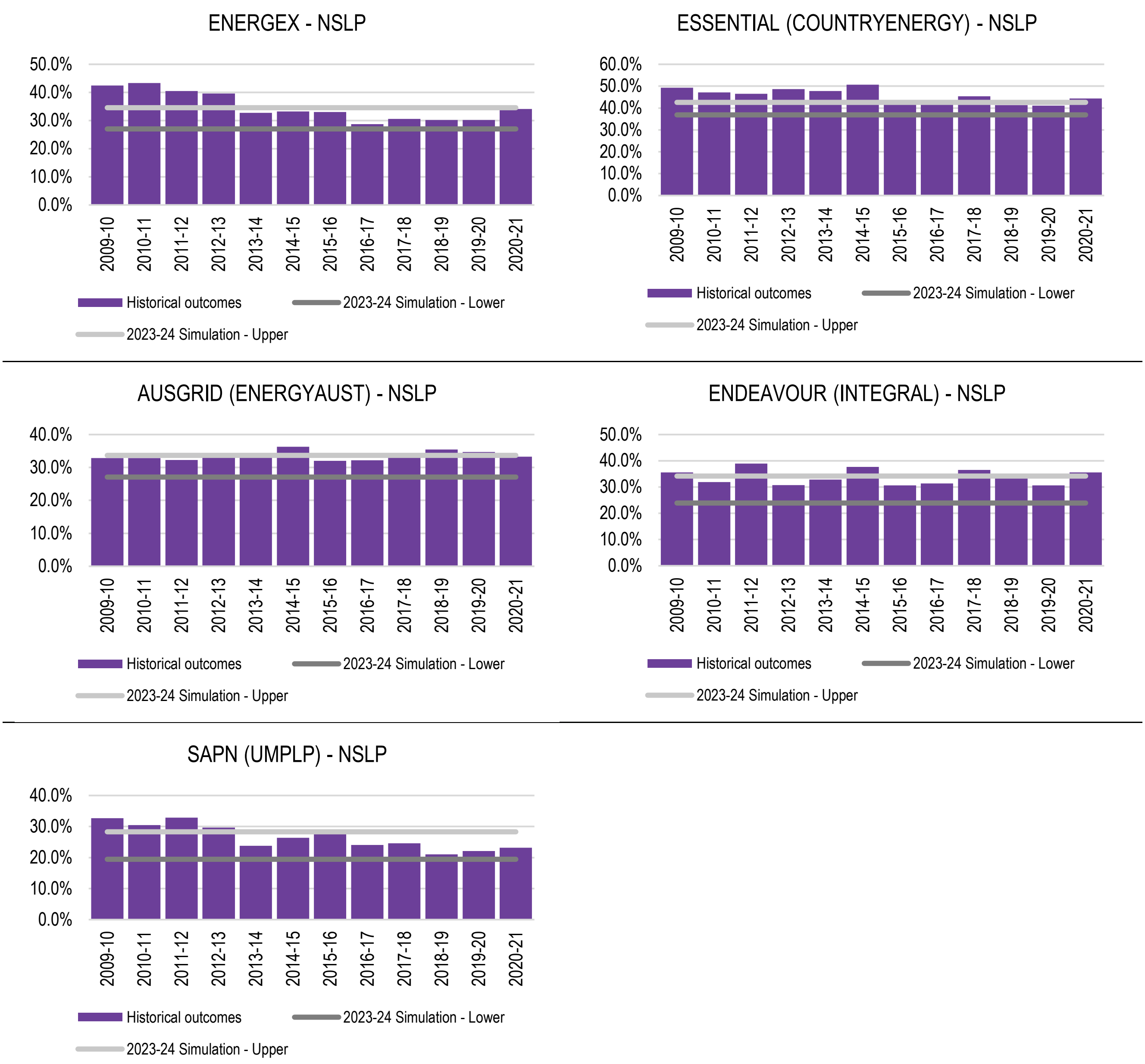
All other things being equal, the increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging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

Figure 4.13 Comparison of upper one per cent of hourly NSLPs of 2023-24 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

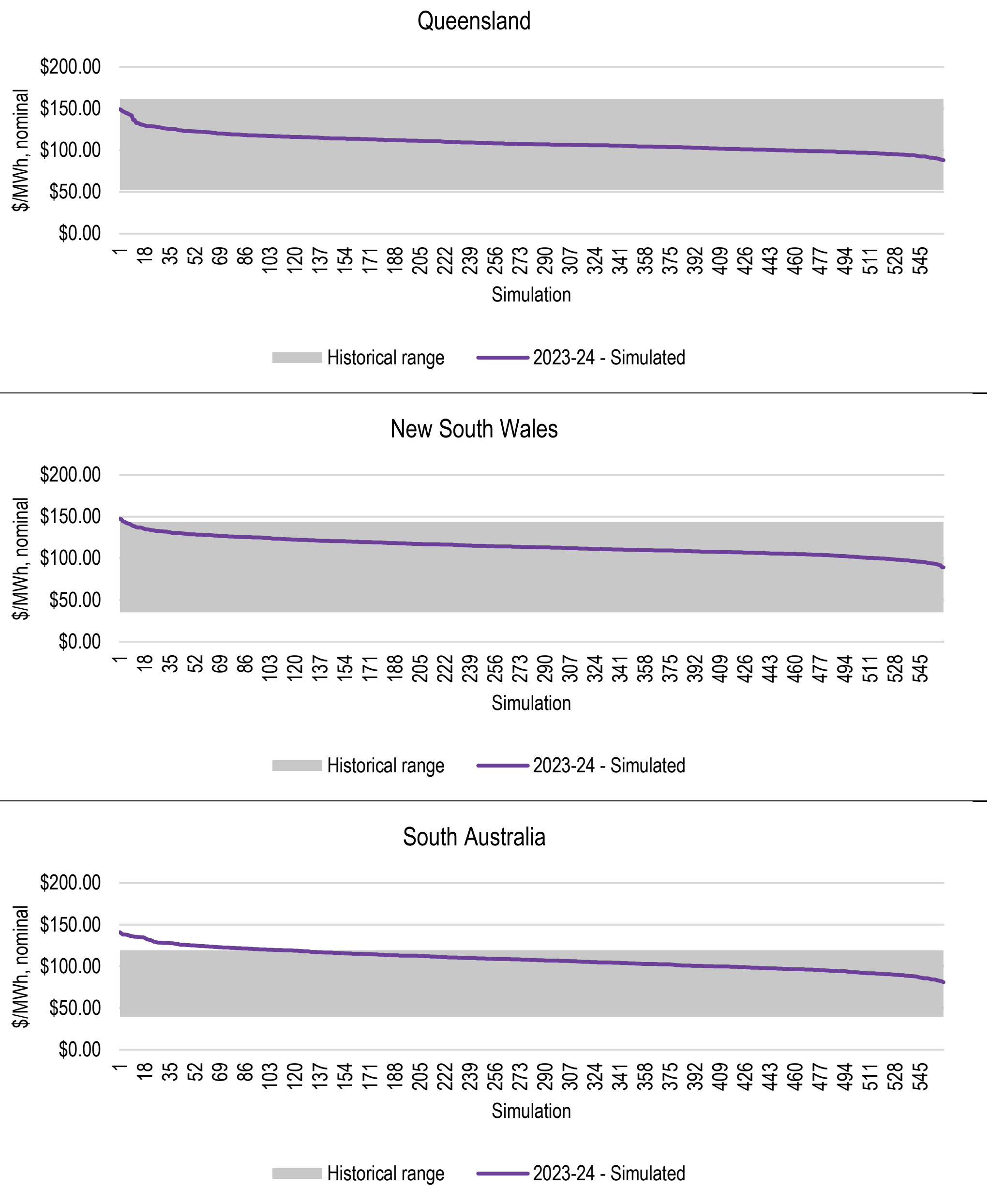
Figure 4.14 Comparison of load factor of 2023-24 simulated hourly demand sets with historical outcomes - NSLPs



Source: ACIL Allen analysis and AEMO data

Figure 4.15 compares the modelled annual regional TWP for the 561 simulations for 2023-24 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 2023-24 when compared with the past 10 years of history.

Figure 4.15 Simulated annual TWP for Queensland, New South Wales, and South Australia for 2023-24 compared with range of actual annual outcomes in past years

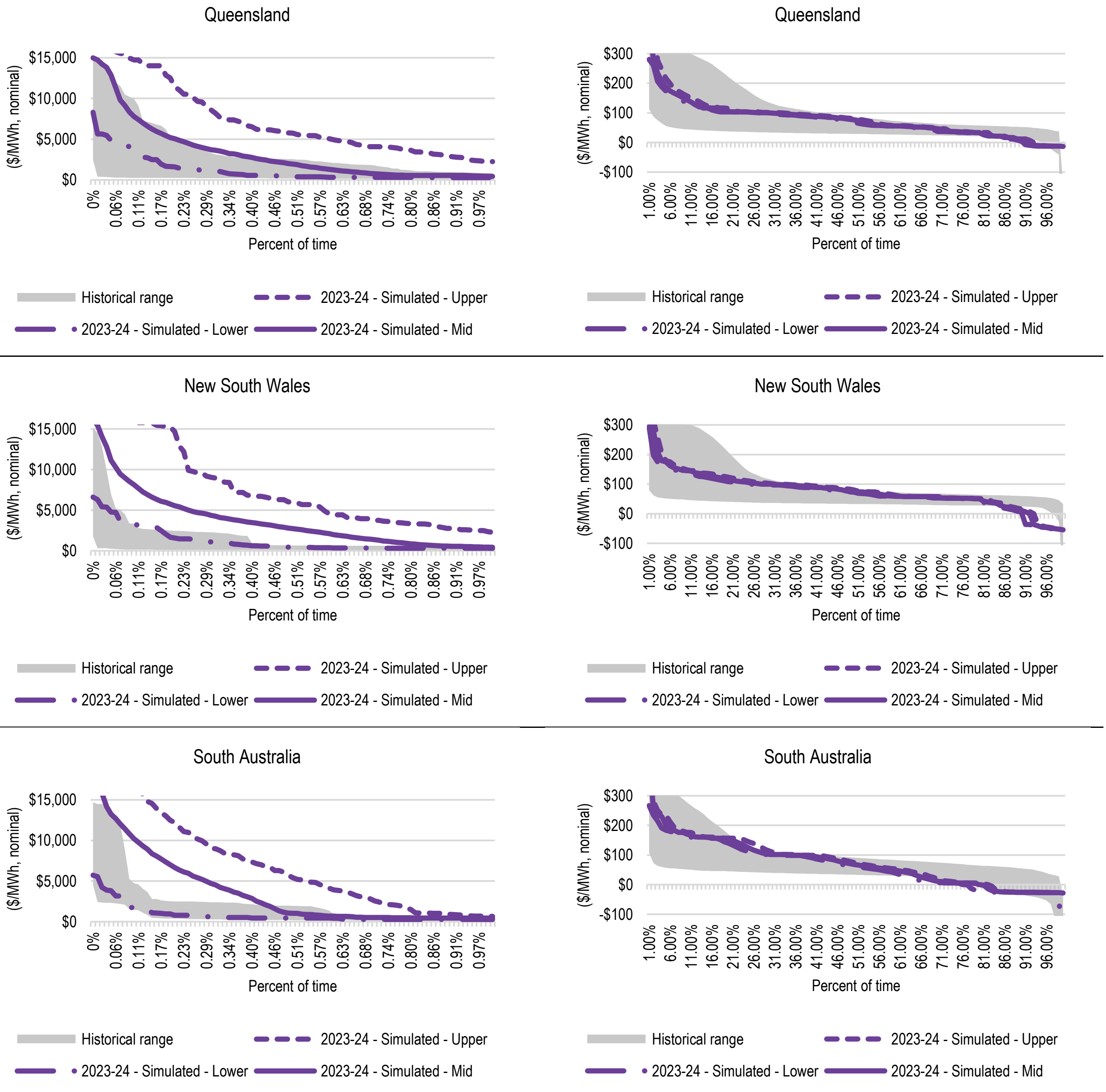


Source: ACIL Allen analysis and AEMO data

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.

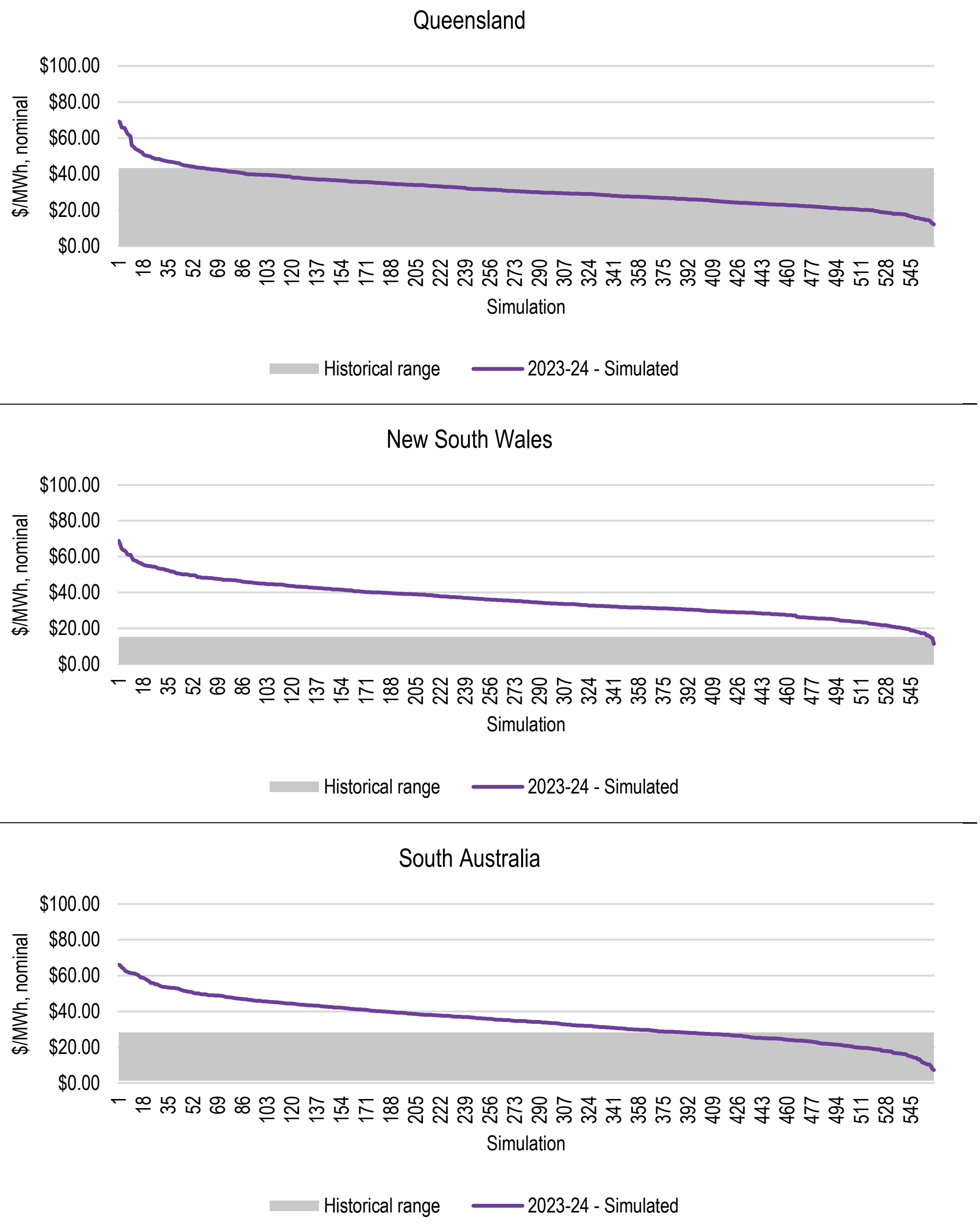
Figure 4.16 Comparison of simulated hourly price duration curves for Queensland, New South Wales, and South Australia for 2023-24 and range of actual outcomes in past years



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 561 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 561 simulations is consistent with those recorded in history as shown in Figure 4.17. For some of the 2023-24 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 2023-24 for simulations compared with range of actual outcomes in past years



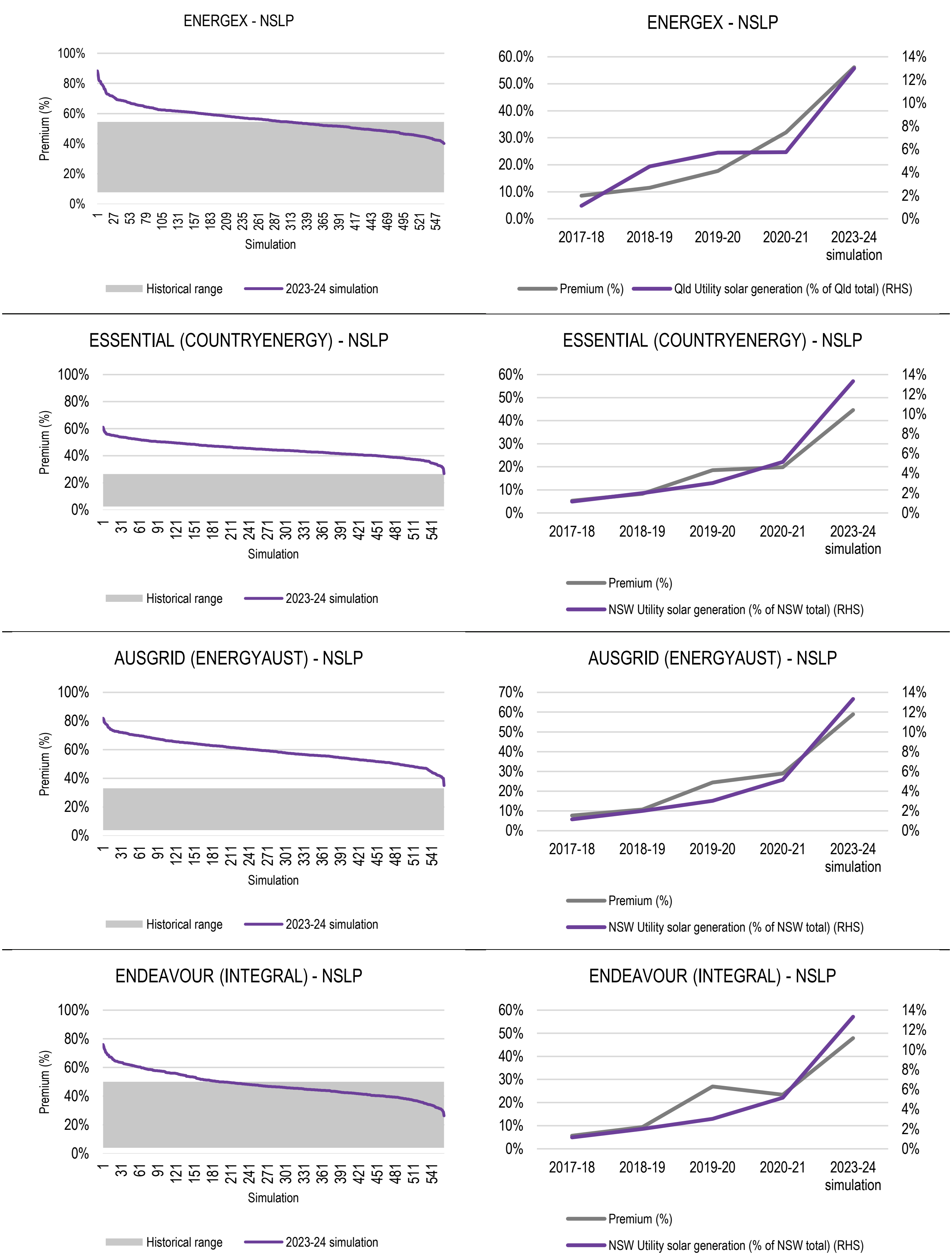
Source: ACIL Allen analysis and AEMO data

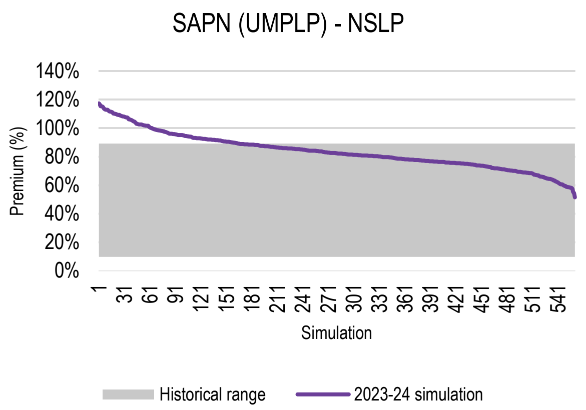
The maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. The shape and volatility of the NSLP demand trace and its relationship to the shape and volatility of the regional demand/price traces is a critical factor in the cost of supplying the NSLP demand.

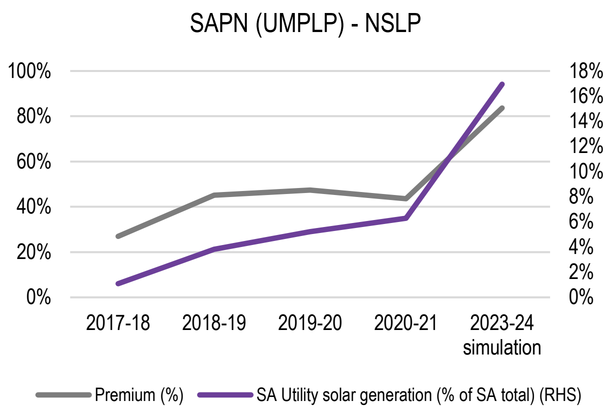
A test of the appropriateness of the simulated NSLP demand shape and its relationship with the regional demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the NSLP with the corresponding regional TWP. Figure 4.18 shows that, for the past 12 financial years, the DWP for NSLPs as a percentage premium over the corresponding regional TWPs has varied from a low of two percent in 2012-13 in New South Wales to a high of 89 percent in South Australia in 2009-10. In the 561 simulations for 2023-24 for each NSLP, this percentage varies from 26 percent to 115 percent.

The modelling suggests a greater range and generally higher level in the premium for 2023-24 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability coupled a decline in price outcomes during daylight hours, due to the commissioning of utility scale PV, when the NSLP 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 as a percentage premium of annual TWP for 2023-24 compared with range of actual outcomes in past years, and market share of utility scale solar (%)







Source: ACIL Allen analysis and AEMO data

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 561 simulations cover the range of expected price outcomes for 2023-24 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 51 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 2023-24.

We note that the variation across the simulated price duration curves is less than recent history for the mid-section of the price duration curve. This is a function of a higher variability in fuel prices in recent years. However, the implementation of coal and gas price caps obviates this to some extent.

4.2.3 Applying the hedge model

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

Contract volumes for 2023-24 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 60th (Essential, Ausgrid, Endeavour) and 50th (Energex, SAPN) percentile of the off-peak period hourly demands across all 51 demand sets for the quarter. This is a decrease compared with 2022-23 reflecting the changing differential between base and cap contract prices, as well as the deeper carve out in the time of day spot price profile due to the strong increase in utility scale solar in 2023-24.

— The cap contract volume is set at 100 per cent of the median of the annual peak demands across the 51 demand sets minus the base and peak contract volumes for all profiles. This is an increase compared with 2022-23, mirroring the decrease in base contract coverage.

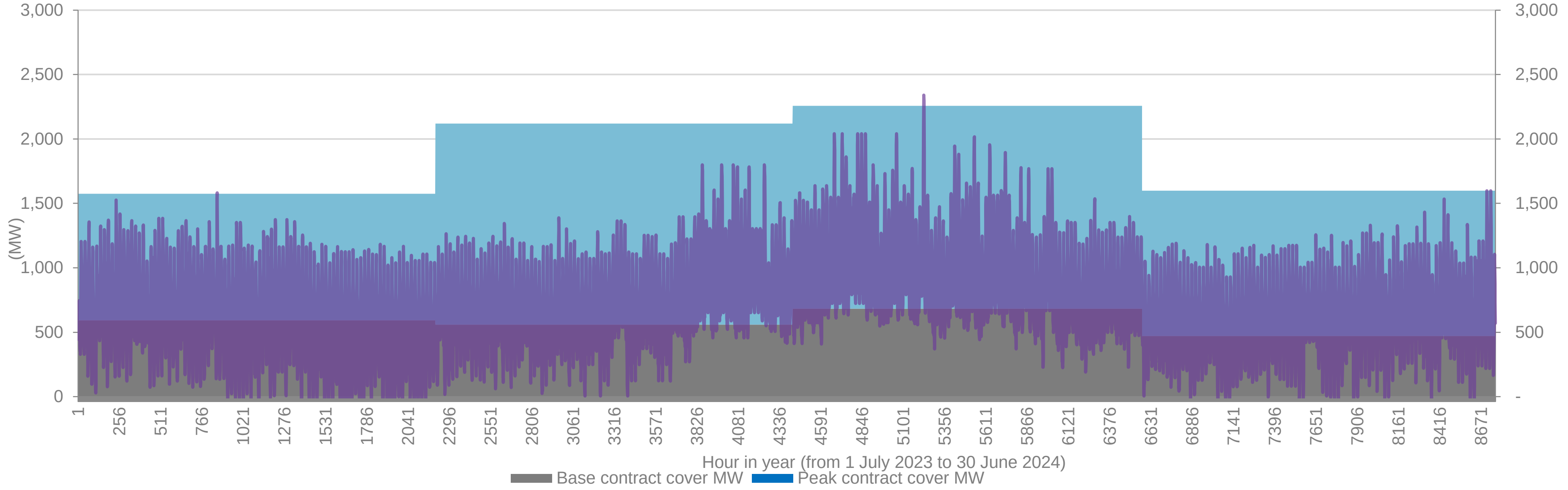
These same hourly hedge volumes (in MW terms) apply to each of the 51 demand sets for a given NSLP and year, and hence to each of the 561 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 51 demand sets. Therefore, the approach we use results 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 561 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.

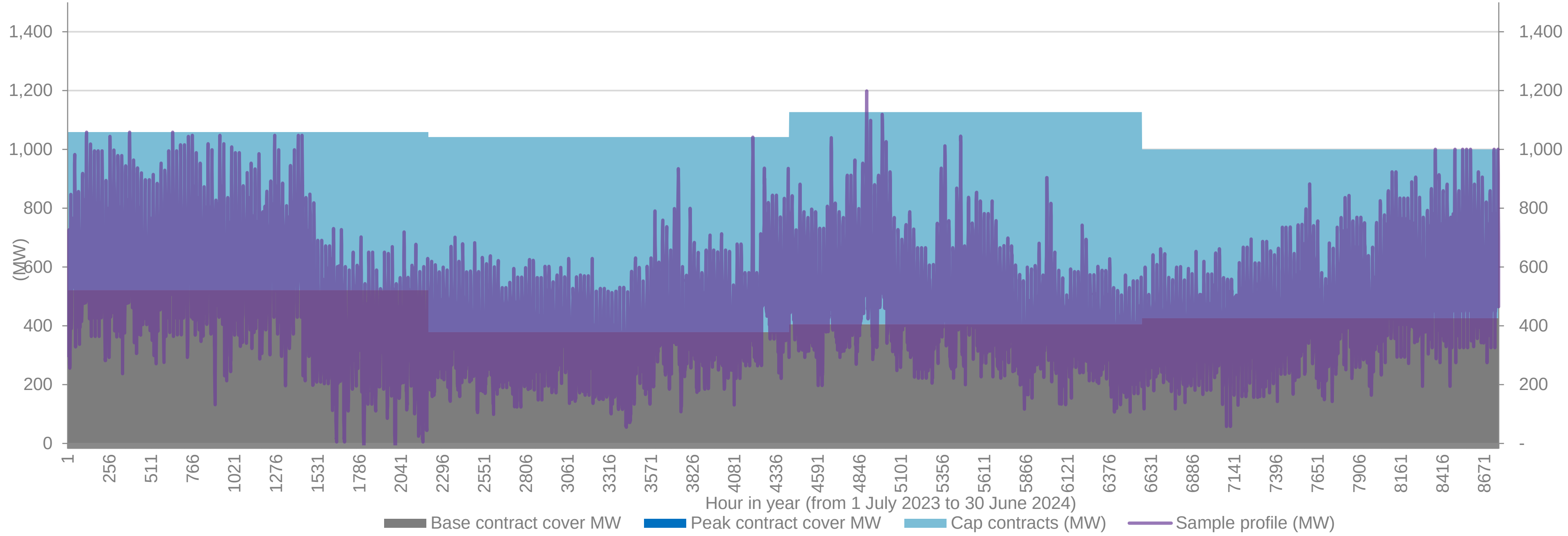
It is worth noting that the triggering of the RRO in South Australia has been taken into account in our analysis since the cap contract volume is set at 100 per cent of the median of the annual peak loads minus the base contract volume. The example profile in **Figure 4.23** is from a simulation that includes loads above the P50 peak and hence are not 100 per cent covered by hedge contracts.

Figure 4.19 Contract volumes used in hedge modelling of 561 simulations for 2023-24 for Energex NSLP



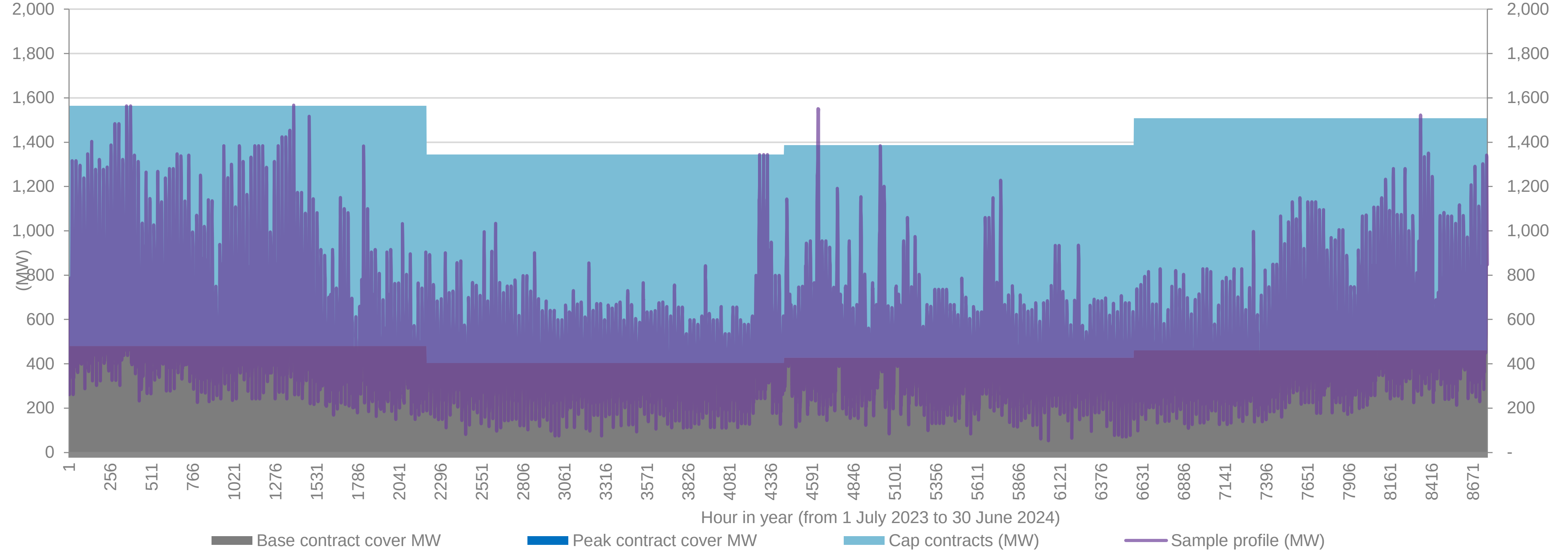
Source: ACIL Allen analysis

Figure 4.20 Contract volumes used in hedge modelling of 561 simulations for 2023-24 for Essential (COUNTRYENERGY)



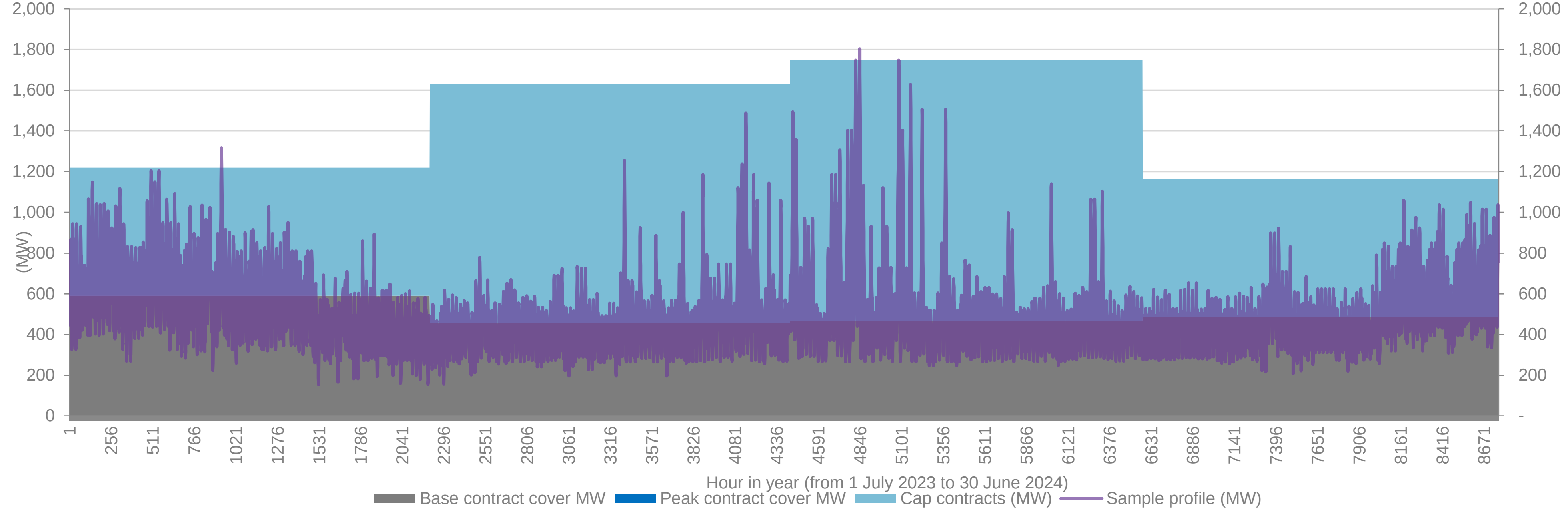
Source: ACIL Allen analysis

Figure 4.21 Contract volumes used in hedge modelling of 561 simulations for 2023-24 for Ausgrid (ENERGYAUST)



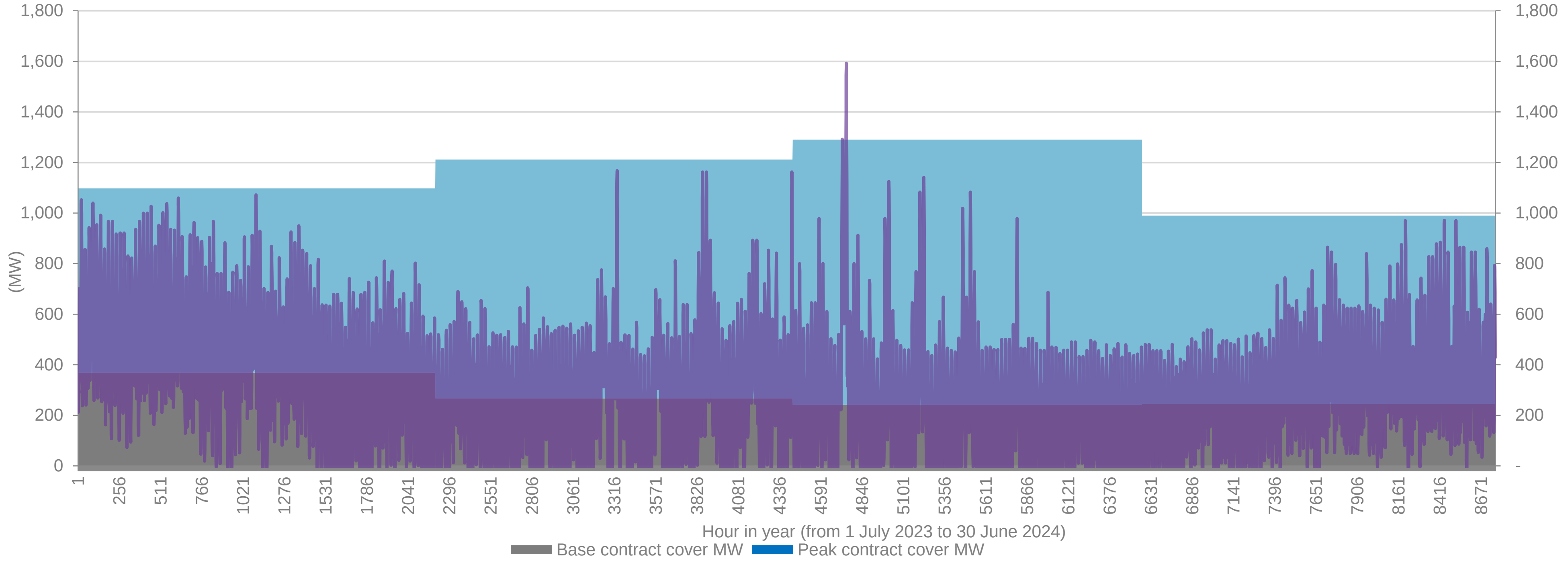
Source: ACIL Allen analysis

Figure 4.22 Contract volumes used in hedge modelling of 561 simulations for 2023-24 for Endeavour (INTEGRAL)



Source: ACIL Allen analysis

Figure 4.23 Contract volumes used in hedge modelling of 561 simulations for 2023-24 for SAPN (UMPLP)

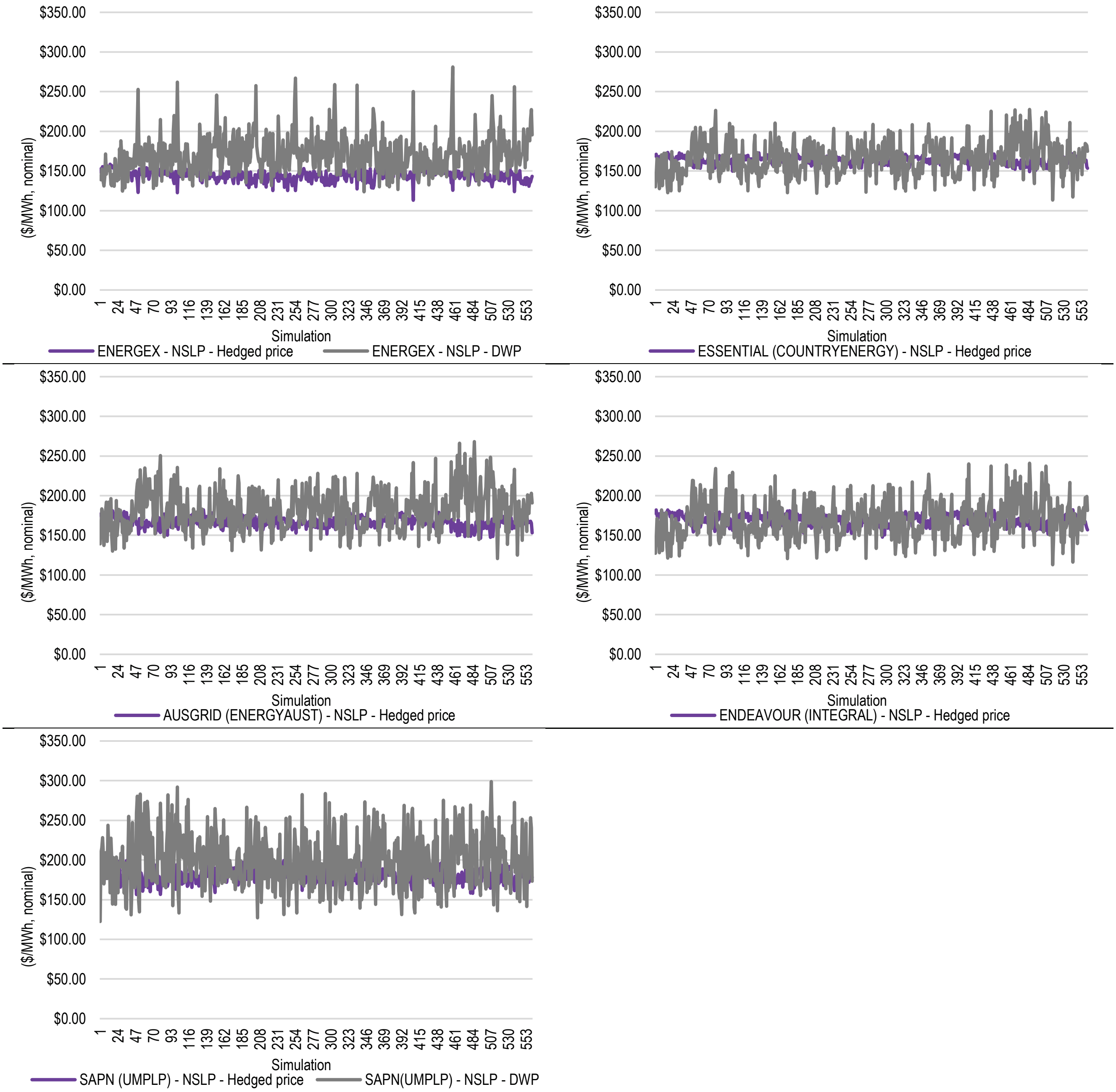


Source: ACIL Allen analysis

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

It is worth noting the hedged price outcomes for some of the NSLPs sit at the lower end of the price continuum compared with the spot price outcomes in many of the simulations. This is a result of the trade weighted average contract prices being less than the spot price simulations for 2023-24.

Figure 4.24 Annual hedged price and DWP ($/MWh, nominal) for NSLPs for the 561 simulations – 2023-24



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 561 WECs (the annual hedged prices). ACIL Allen's estimate of the WEC for each tariff class for 2023-24 are shown in Table 4.4 and compared to the WEC estimates in the 2022-23 Final Determination.

Table 4.4 Estimated WEC ($/MWh, nominal) for 2023-24 at the regional reference node

Settlement class	2022-23 – Final Determination	2023-24 – Final Determination	Change from 2022-23 to 2023-24 (%)
Ausgrid - NSLP	$111.99	$172.23	53.79%
Endeavour - NSLP	$113.22	$174.45	54.08%
Essential - NSLP	$107.65	$166.72	54.87%
Ausgrid - CLP1	$79.83	$100.74	26.19%
Ausgrid - CLP2	$78.54	$100.50	27.96%
Endeavour - CLP	$104.02	$163.26	56.95%
Essential - CLP	$80.28	$100.72	25.46%
Energex - NSLP	$97.45	$150.91	54.86%
Energex - CLP1	$75.07	$99.82	32.98%
Energex - CLP2	$81.46	$106.65	30.93%
SAPN - NSLP	$109.46	$189.87	73.46%
SAPN - CLP	$54.00	$85.46	58.27%

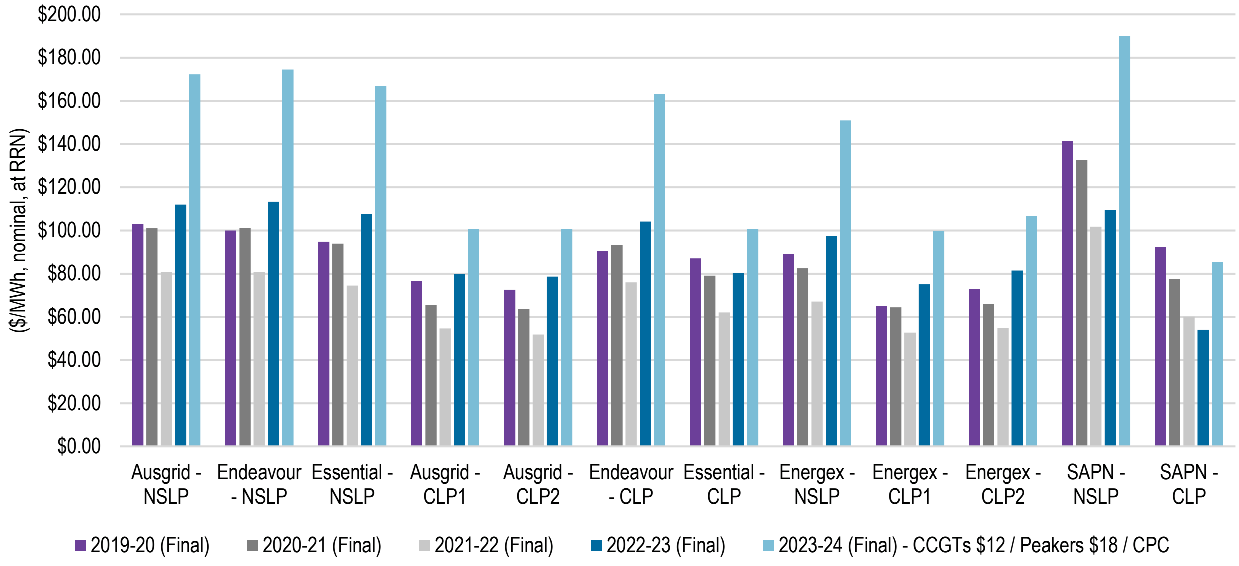
Source: ACIL Allen analysis

The 2023-24 WECs for the NSLPs increase by between 54 and 73 per cent, and CLPs increase by between 26 and 58 per cent compared with 2022-23 – reflecting the strong increase in base and cap contract prices and the 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 tariff class 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. The increase in WECs in 2023-24 means they are higher than the WECs estimated for 2019-20 (the previous peak in WEC values).

Figure 4.25 Estimated WEC ($/MWh, nominal) for 2023-24 at the regional reference node in comparison with WECs from previous determinations



Source: ACIL Allen analysis

4.2.5 Do the changes in WEC make intuitive sense?

An increase in WEC of 50 to 85 per cent is very large and will impact the cost of living for residential consumers, as well as the input costs for businesses for which electricity represents a high proportion of production input.

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 Final 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.

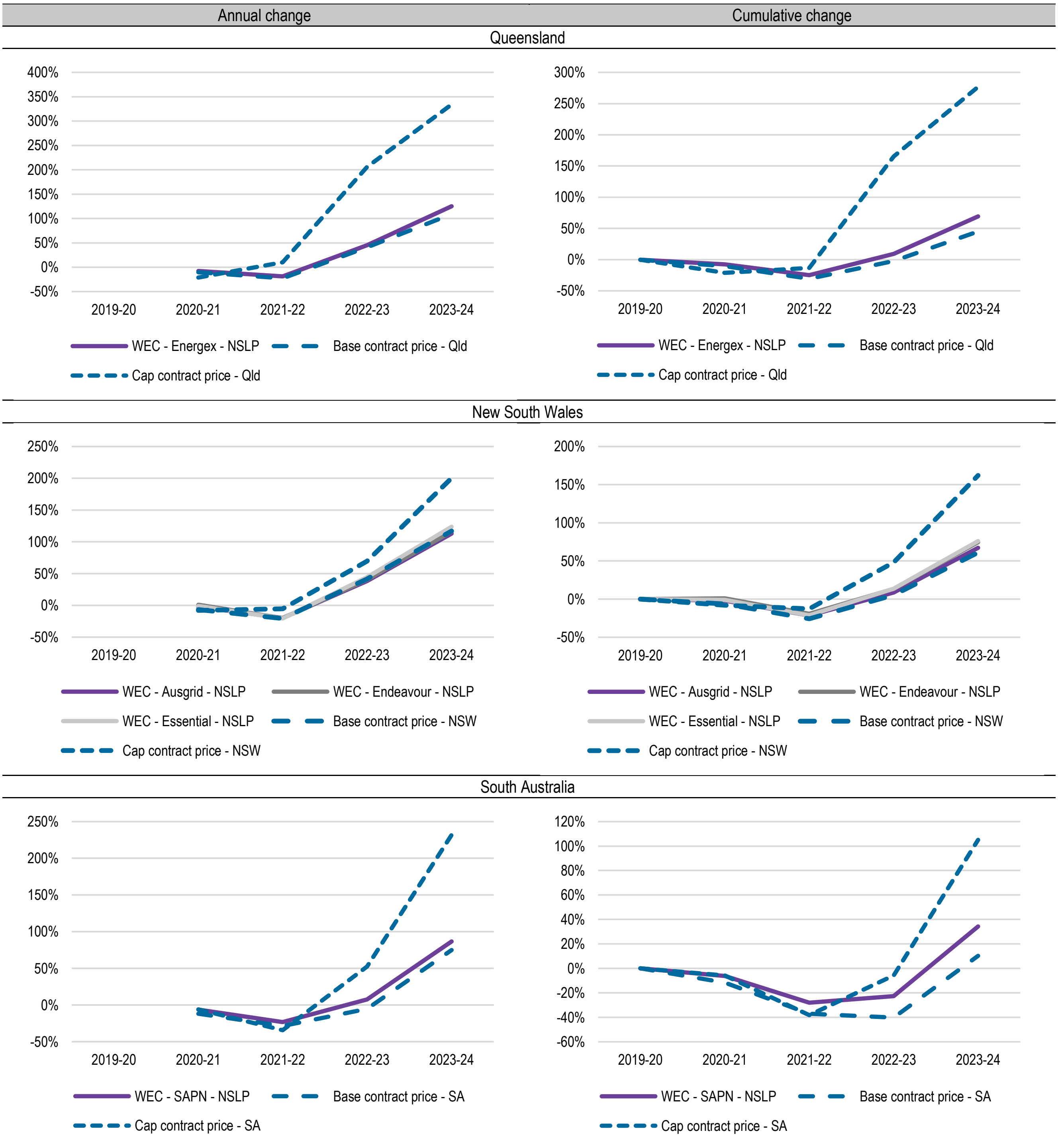
— The trend in WECs aligns very closely to the trend in base contract prices. This is not surprising given the stronger reliance on base contracts in the hedging strategy.

— 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 2023-24, and that the estimated WECs reflect the consensus view of market conditions for the given determination year at the time the determination was made.

Figure 4.26 Change in WEC and trade weighted contract prices (%) – 2019-20 to 2023-24



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[12]) 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 (previously TFS), 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 2023 and 2024 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 2023 and 2024 from brokers TFS
— estimated Renewable Power Percentages (RPP) values for 2023 and 2024 of 18.96 per cent[13]
— binding Small-scale Technology Percentage (STP) values for 2023 of 16.29 per cent, as published by CER
— estimated STP value for 2024 of 17.99 per cent[14]
— CER clearing house price[15] 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 10 May 2023.

[12] 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.

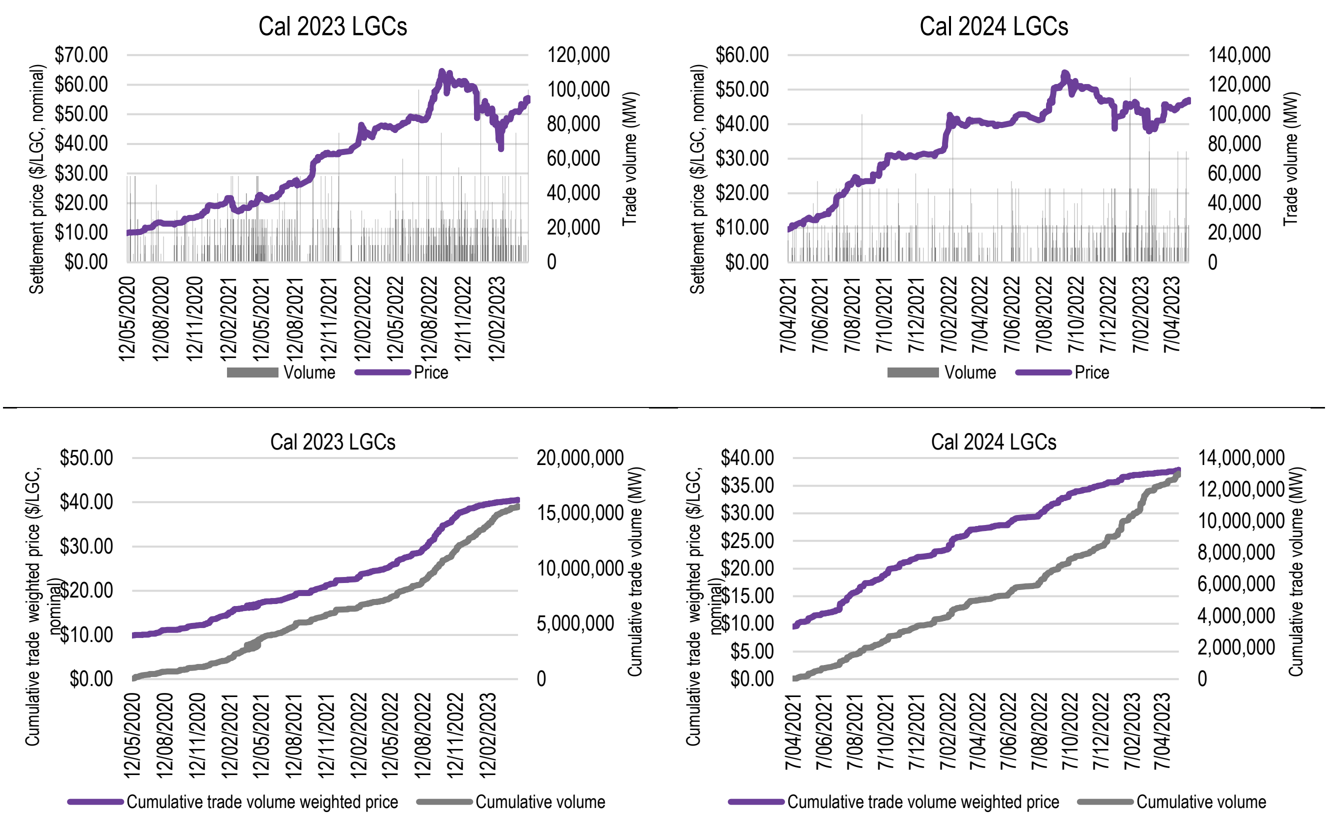
[13] The RPP values for 2023 and 2024 are based on the CER's published RPP for 2023 and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2023 and 2024.

[14] The STP value for 2024 is based on the CER's non-binding STP.

[15] 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 2023-24 is found by taking the trade-weighted average of the forward prices for the 2023 and 2024 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 $40.56/MWh for 2023 and $37.85/MWh for 2024**.**

Figure 4.27 LGC prices and trade volumes for 2023 and 2024 for 2023-24 ($/LGC, nominal)



Source: ACIL Allen analysis of TraditionAsia

The RPP value for 2023 was set by the CER on 6 February 2023 at 18.96 per cent. The RPP value for 2024 is estimated by using the mandated target for 2024 of 33 TWh and the CER's published cumulative adjustment and estimate of electricity acquisitions in 2022 of 175.10 TWh. In other words, ACIL Allen has assumed electricity acquisitions remain constant in 2023 and 2024, and hence the RPP values for 2023 and 2024 are both 18.96 per cent.

Key elements of the 2023 and 2024 RPP estimation are shown in Table 4.5.

Table 4.5 Estimating the 2023 and 2024 RPP values

	2023	2024 (estimate based on 2023 RPP)
LRET target, MWh (CER)	33,206,106	33,206,106
Relevant acquisitions minus exemptions, MWh (CER)	175,100,000	175,100,000
Estimated RPP	18.96%	18.96%

Source: ACIL Allen analysis of CER data

ACIL Allen calculates the cost of complying with the LRET in 2023 and 2024 by multiplying the RPP values for 2023 and 2024 by the trade volume weighted average LGC prices for 2023 and

2024, respectively. The cost of complying with the LRET in 2023-24 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $7.44/MWh in 2023-24 as shown in Table 4.6.

Table 4.6 Estimated cost of LRET – 2023-24

	2023	2024	Cost of LRET 2023-24
RPP %	18.96%	18.96%	
Trade weighted average LGC price ($/LGC, nominal)	$40.56	$37.85	
Cost of LRET ($/MWh, nominal)	$7.69	$7.18	$7.44

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 2023-24.

ACIL Allen estimates the cost of complying with SRES to be $6.86/MWh in 2023-24 as set out in Table 4.7.

Table 4.7 Estimated cost of SRES – 2023-24

	2023	2024	Cost of SRES 2023-24
STP %	16.29%	17.99%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$6.52	$7.20	$6.86

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 2023-24 as set out in Table 4.8.

Since the 2022-23 estimate, the cost of LRET has increased by around 45 per cent, driven by higher LGC prices in 2023-24, and the cost of SRES has decreased by 37 per cent, driven by the shortening of the SRES deeming period.

Table 4.8 Total renewable energy policy costs ($/MWh, nominal) – 2023-24

	2022-23	2023-24
LRET	$5.13	$7.44
SRES	$10.90	$6.86
Total	**$16.03**	**$14.30**

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 2023 and 2024 of 9.5 and 10 per cent respectively, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2023 and 2024 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 2023-24, as set out in Table 4.9. The 2023-24 estimate of $3.20/MWh is slightly lower than the 2022-23 estimate of $3.39/MWh – reflecting lower certificate prices which offset the increase in the ESS target.

Table 4.9 Estimated cost of ESS ($/MWh, nominal) – 2023-24

	2023	2024	Cost of ESS 2023-24
ESS target	$32.77	$32.92	
Average ESC price ($/MWh, nominal)	9.50%	10.00%	
Cost of ESS ($/MWh, nominal)	$3.11	$3.29	$3.20

Source: IPART, TFS data up to 25 March 2022

4.3.5 New South Wales Peak Demand Reduction Scheme (PDRS)

To estimate the cost of complying with the PDRS for 2023-24, ACIL Allen has used the following elements:

— The peak demand reduction target for 2023-24 of one 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 2023-24 of 13,859 MW as published by AEMO in its 2022 ESOO, this equates to 138,590 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.
— The post-tax penalty rate of $3.53/PRC. As PRC trade volume and price data becomes available, we propose to estimate the PRC price as the trade volume weighted average price.
— The annual energy requirements for New South Wales in 2023-24 of 63,886 GWh as published by AEMO in its 2022 ESOO.

The estimated cost of the PDRS for 2023-24 is $0.46/MWh.

Table 4.10 Estimated cost of PDRS ($/MWh, nominal) – 2023-24

Item	Value
PRC price ($/PRC, nominal) per 0.1kW of peak demand reduction capacity averaged across one hour	$3.53
PDRS target (percentage reduction in peak demand)	1.0%
PDRS target (kW reduction in peak demand)	138,590
PRC target (certificates)	8,315,418
Total cost of PDRS ($, nominal)	$29,311,848
Cost of PDRS per certificate ($/PRC, nominal)	$0.21
NSW operational energy requirements (GWh)	63,886
Cost of PDRS ($/MWh)	$0.46

Source: ACIL Allen analysis

Item	Value

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.

In our reports for the previous DMOs, given the limited availability of public data on the cost of meeting the REPS, we assumed the cost was $2.50/MWh – the same cost as its predecessor, the REES.

ESCOSA has published some data on the first year of the REPS scheme and reports an average cost of delivering the energy savings required under the scheme as $14.42/GJ. We multiplied the $14.42/GJ by the target in that year of 2,500,000 GJ, and then divided the total cost by the total customer energy in South Australia, to give a cost of $3.19/MWh.

4.4 Estimation of other energy costs

The estimates of other energy costs for the Final 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)[16], 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 released its draft budget report for 2023-24, which we have used.

Based on the fees provided by AEMO's *Draft FY24 Budget and Fees,* our estimate of the fees for 2022-23 are $0.95/MWh (down from $1.10/MWh for 2022-23 in DMO 4). The breakdown of total fees is shown in Table 4.11. The decrease in fees largely relates to the decrease in NEM core fees.

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Table 4.11 NEM management fees ($/MWh, nominal) – 2023-24

Cost category	2022-23	2023-24
NEM fees (admin, registration, etc.)	$0.75	$0.57
FRC - electricity	$0.078	$0.0802

[16] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2022-23* 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.

Cost category	2022-23	2023-24
ECA - electricity	$0.034	$0.0404
DER fee	$0.024	$0.02370
IT upgrade and 5MS/GS compliance	$0.219	$0.2438
Total NEM management fees	**$1.10**	**$0.95**

Source: ACIL Allen analysis of AEMO reports

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 28 April 2023) of available NEM ancillary services data as a basis for 2023-24, the estimates cost of ancillary services is shown in Table 4.12.

Ancillary service costs have stabilised on an annual basis in New South Wales.

Ancillary service costs have declined to more normal levels in Queensland over the past 12 months. Noting that in 2022-23, the noticeable increase in weekly ancillary service costs in Queensland was a result of upgrade works associated with the QNI which gave rise to price separation between the two regions.

Ancillary service costs have increased noticeably in South Australia – largely due to the islanding event on 12 November 2022 because of a transmission tower failure.

Table 4.12 Ancillary services ($/MWh, nominal) – 2023-24

Region	2022-23	2023-24
Queensland	$1.42	$0.47
New South Wales	$0.34	$0.46
South Australia	$0.48	$2.11

Source: ACIL Allen analysis of AEMO data

4.4.3 Prudential costs

Prudential costs have been calculated for each jurisdiction NSLP. The prudential costs for the NSLP 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 4.13 for each season for the Energex NSLP gives an estimated MCL of $19,391

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 $19,391/42 = $461.70/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 $461.70 gives $1.33/MWh for the Energex NSLP.

The components of the AEMO prudential costs for each of the other jurisdictions' NSLPs are shown in Table 4.13 to Table 4.17.

Table 4.13 AEMO prudential costs for Energex NSLP – 2023-24

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$145.59	$126.92	$119.74
Participant Risk Adjustment Factor	1.5552	1.7552	1.7015
OS Volatility factor	1.51	1.55	1.41
PM Volatility factor	2.98	2.19	1.88
OSL	$16,416	$17,612	$14,426
PML	$3,283	$3,522	$2,885
MCL	$19,699	$21,134	$17,312
Average MCL		$19,391	
AEMO prudential cost ($/MWh, nominal)		**$1.33**	

Source: ACIL Allen analysis of AEMO data

Table 4.14 AEMO prudential costs for Ausgrid NSLP – 2023-24

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$122.69	$200.49	$99.02
Participant Risk Adjustment Factor	1.4834	1.6134	1.2256
OS Volatility factor	1.56	1.53	1.36
PM Volatility factor	3.04	0.00	2.04
OSL	$13,313	$24,202	$7,034
PML	$2,663	$4,840	$1,407
MCL	$15,976	$29,042	$8,441
Average MCL		$17,881	
AEMO prudential cost ($/MWh, nominal)		**$1.22**	

Source: ACIL Allen analysis of AEMO data

Table 4.15 AEMO prudential costs for Endeavour NSLP – 2023-24

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$122.69	$200.49	$99.02
Participant Risk Adjustment Factor	1.5569	1.2741	1.1735
OS Volatility factor	1.56	1.53	1.36
PM Volatility factor	3.04	2.25	2.04
OSL	$14,314	$16,985	$6,591
PML	$2,863	$3,397	$1,318

Factor	Summer	Winter	Shoulder
MCL	$17,177	$20,382	$7,909
Average MCL		$15,184	
AEMO prudential cost ($/MWh, nominal)		**$1.04**	

Source: ACIL Allen analysis of AEMO data

Table 4.16 AEMO prudential costs for Essential NSLP – 2023-24

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$122.69	$200.49	$99.02
Participant Risk Adjustment Factor	1.2786	1.2448	1.2952
OS Volatility factor	1.56	1.53	1.36
PM Volatility factor	3.04	2.25	2.04
OSL	$10,654	$16,402	$7,642
PML	$2,131	$3,280	$1,528
MCL	$12,784	$19,682	$9,171
Average MCL		$13,911	
AEMO prudential cost ($/MWh, nominal)		**$0.95**	

Source: ACIL Allen analysis of AEMO data

Table 4.17 AEMO prudential costs for SAPN NSLP – 2023-24

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$107.75	$243.20	$94.57
Participant Risk Adjustment Factor	1.6968	1.4735	1.1668
OS Volatility factor	1.79	1.57	1.41
PM Volatility factor	4.43	2.29	1.89
OSL	$16,412	$26,294	$6,471
PML	$3,282	$5,259	$1,294
MCL	$19,695	$31,553	$7,765
Average MCL		$19,736	
AEMO prudential cost ($/MWh, nominal)		**$1.35**	

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 3.85 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 20 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 4.18. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 8.86 per cent but adjusted for an assumed 3.85 per cent return on cash lodged with the clearing (giving a net funding cost of 5.01 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 4.18 to Table 4.20, respectively.

Table 4.18 Hedge Prudential funding costs by contract type – Queensland 2023-24

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$98.36	$53,000	$1.21
Cap	$24.24	$20,000	$0.46

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.19 Hedge Prudential funding costs by contract type – New South Wales 2023-24

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$125.93	$58,000	$1.33
Cap	$24.99	$17,000	$0.39

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.20 Hedge Prudential funding costs by contract type – South Australia 2023-24

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$96.70	$60,000	$1.37
Cap	$27.36	$22,000	$0.50

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 4.21 to Table 4.25**.**

Table 4.21 Hedge Prudential funding costs for ENERGEX NSLP – 2023-24

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.21	0.8621	$1.05
Cap	$0.46	1.9593	$0.90
Total cost		**$1.94**	

Source: ACIL Allen analysis

Table 4.22 Hedge Prudential funding costs for Ausgrid NSLP – 2023-24

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.33	0.9064	$1.20
Cap	$0.39	2.0623	$0.80
Total cost		**$2.00**	

Source: ACIL Allen analysis

Table 4.23 Hedge Prudential funding costs for Endeavour NSLP – 2023-24

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.33	0.9858	$1.31
Cap	$0.39	1.8524	$0.72
Total cost		**$2.03**	

Source: ACIL Allen analysis

Table 4.24 Hedge Prudential funding costs for Essential NSLP – 2023-24

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.33	0.9738	$1.29
Cap	$0.39	1.4033	$0.55
Total cost		**$1.84**	

Source: ACIL Allen analysis

Table 4.25 Hedge Prudential funding costs for SAPN NSLP – 2023-24

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.37	0.9084	$1.25
Cap	$0.50	2.7741	$1.40
Total cost		**$2.64**	

Source: ACIL Allen analysis

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2023-24 as set out in Table 4.26. Prudential costs for 2023-24 are generally slightly higher than 2023-24 due to higher prices and higher expected price volatility across 2023-24. There is a slight decline in the prudential costs in South Australia due to a change in the hedge mix.

Table 4.26 Total prudential costs ($/MWh, nominal) – 2023-24

Jurisdiction	2022-23	2023-24
Energex NSLP	$2.61	$3.27
Ausgrid NSLP	$2.65	$3.23
Endeavour NSLP	$2.56	$3.07
Essential NSLP	$2.31	$2.79
SAPN NSLP	$4.23	$3.99

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 Final Determination.

Excluding the June 2022 NEM events, AEMO activated the RERT twice for the 12-month period prior to the Final Determination in Queensland.

AEMO contracted 63 MW in Queensland on 5 July 2022, in response to a forecast Lack of Reserve (LOR) 2 condition. AEMO reported the costs of this activation to be $639,016. When dividing this value by the total energy requirements in Queensland, the cost of the RERT is about one cent per MWh.

On 3 February 2023, AEMO activated the RERT in Queensland due to a forecast Lack of Reserve (LOR) Condition 2. AEMO reported the costs of this activation to be $1,475,000. When dividing this value by the total energy requirements in Queensland, the cost of the RERT is about three cents per MWh.

In total, the RERT costs for Queensland for the Final Determination are set at $0.04/MWh.

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

4.4.5 Retailer Reliability Obligation

The RRO is currently triggered for 2023-24 in South Australia. We have adjusted the contracting strategy to ensure the P50 peak demand is covered by hedges.

The RRO is not currently triggered for Queensland or New South Wales for 2023-24.

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 $7.04/MWh, as slight increase from the 2022-23 cost of $7.03/MWh. 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 in the DMO regions, ACIL Allen has used AEMO's published estimates of the costs of the June 2022 events, published on 6 January 2023, as well as AEMC's final decisions on administered pricing compensation claims, published in March and April 2023. For the compensation decisions made in March and April 2023, ACIL Allen has used AEMC's published compensation costs (in $ terms) and allocated them to NEM regions in proportion to energy purchased in each relevant region (in $/MWh terms), in accordance with the National Electricity Rules.

The total cost to date for is shown below, which when recovered across the customer load equates to $0.90/MWh, $2.06/MWh, and $0.68/MWh for Queensland, New South Wales, and South Australia respectively.

Table 4.27 Cost of June 2022 NEM events -

Item	Queensland	New South Wales	South Australia
RERT payments (for activated demand response under RERT contracts)	$3,800,000	$78,400,000	$0
Directions compensation (directed participants for energy, ancillary services or other compensable services)	$9,070,000	$5,020,000	$910,000
Suspension pricing compensation (for eligible costs not recovered by spot prices when set/affected by market suspension pricing schedule prices)	$25,560,000	$37,900,000	$6,700,000
Administered pricing compensation (for eligible costs when spot market prices were set/affected by the administered price cap)	$6,570,550	$11,105,255	$101,701
Total	$45,000,550	$132,425,255	$7,711,701

Source: ACIL Allen analysis of AEMO June 2022 NEM Events: Compensation Update (6 January 2023) and AEMC final decisions on administered price cap compensation claims (23 March 2023 and 6 April 2023).

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 2023-24 Final Determination and is compared with the costs for 2022-23.

Table 4.28 Total of other costs ($/MWh, nominal) – Energex NSLP – 2023-24

Cost category	2022-23	2023-24
NEM management fees	$1.10	$0.95
Ancillary services	$1.42	$0.47
Hedge and pool prudential costs	$2.61	$3.27
Reserve and Emergency Reserve Trader costs	$1.01	$0.04
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events		$0.90
Total	**$6.14**	**$5.63**

Source: ACIL Allen analysis

Table 4.29 Total of other costs ($/MWh, nominal) – Ausgrid NSLP – 2023-24

Cost category	2022-23	2023-24
NEM management fees	$1.10	$0.95
Ancillary services	$0.34	$0.46
Hedge and pool prudential costs	$2.65	$3.23
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events		$2.06
Total	**$4.09**	**$6.70**

Source: ACIL Allen analysis

Table 4.30 Total of other costs ($/MWh, nominal) – Endeavour NSLP – 2023-24

Cost category	2022-23	2023-24
NEM management fees	$1.10	$0.95
Ancillary services	$0.34	$0.46
Hedge and pool prudential costs	$2.56	$3.07
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events		$2.65
Total	**$4.00**	**$6.54**

Source: ACIL Allen analysis

Table 4.31 Total of other costs ($/MWh, nominal) – Essential NSLP – 2023-24

Cost category	2022-23	2023-24
NEM management fees	$1.10	$0.95
Ancillary services	$0.34	$0.46
Hedge and pool prudential costs	$2.31	$2.79
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events		$2.06
Total	**$3.75**	**$6.26**

Source: ACIL Allen analysis

Table 4.32 Total of other costs ($/MWh, nominal) – SAPN NSLP – 2023-24

Cost category	2022-23	2023-24
NEM management fees	$1.10	$0.95
Ancillary services	$0.48	$2.11
Hedge and pool prudential costs	$4.23	$3.99
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$7.03	$7.04
June 2022 NEM events		$0.68
Total	**$12.84**	**$14.77**

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 the Final Determination for 2023-24 are based on the 2023-24 MLFs and DLFs published by AEMO in March and April 2023 respectively.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2023-24 is shown in Table 4.33.

Table 4.33 Estimated transmission and distribution losses

	2022-23			2023-24		
	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 - NSLP	4.89%	0.37%	1.053	4.82%	-0.81%	1.040
Endeavour - NSLP	6.80%	-0.76%	1.060	6.91%	-2.02%	1.047
Essential - NSLP	6.09%	-1.83%	1.041	5.88%	-2.80%	1.029
Ausgrid - CLP1	5.17%	0.37%	1.056	5.05%	-0.81%	1.042
Ausgrid - CLP2	5.17%	0.37%	1.056	5.05%	-0.81%	1.042
Endeavour - CLP	6.80%	-0.76%	1.060	6.91%	-2.02%	1.047
Essential - CLP	6.09%	-1.83%	1.041	5.88%	-2.80%	1.029
Energex - NSLP	6.11%	0.56%	1.067	5.91%	0.72%	1.067
Energex – CLP31	6.11%	0.56%	1.067	5.91%	0.72%	1.067
Energex – CLP33	6.11%	0.56%	1.067	5.91%	0.72%	1.067
SAPN - NSLP	10.70%	-0.64%	1.100	11.09%	-0.50%	1.105
SAPN - CLP	10.70%	-0.64%	1.100	11.09%	-0.50%	1.105

Source: ACIL Allen analysis of AEMO data

As described by AEMO[17], 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)*

[17] 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 2023-24 total energy costs (TEC) for the Final Determination for each of the profiles are presented in Table 4.33 and Table 4.35.

Table 4.34 Estimated TEC for 2023-24 ($/MWh, nominal) – Final Determination

Profile	2022-23 Total energy costs at the customer terminal ($/MWh, nominal)	2023-24 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2022-23 to 2023-24 ($/MWh, nominal)	Change from 2022-23 to 2023-24 (%, nominal)
Ausgrid - NSLP	$142.91	$204.77	$61.86	43.29%
Endeavour - NSLP	$145.07	$208.30	$63.23	43.59%
Essential - NSLP	$136.42	$196.48	$60.06	44.03%
Ausgrid - CLP1	$109.36	$130.66	$21.30	19.48%
Ausgrid - CLP2	$108.00	$130.41	$22.41	20.75%
Endeavour - CLP	$135.32	$196.58	$61.26	45.27%
Essential - CLP	$107.93	$128.56	$20.63	19.11%
Energex - NSLP	$127.63	$182.29	$54.66	42.83%
Energex – CLP31	$103.75	$127.78	$24.03	23.16%
Energex – CLP33	$110.57	$135.06	$24.49	22.15%
SAPN - NSLP	$154.91	$245.46	$90.55	58.45%
SAPN - CLP	$93.90	$130.08	$36.18	38.53%

Source: ACIL Allen analysis

Table 4.35 Estimated TEC for 2023-24 Final 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 - NSLP	$172.23	$6.70	1.040	$7.16	$186.09	$7.44	$6.86	$3.66	$0.72	$18.68	$204.77
Endeavour - NSLP	$174.45	$6.54	1.047	$8.51	$189.50	$7.44	$6.86	$3.66	$0.84	$18.80	$208.30
Essential - NSLP	$166.72	$6.26	1.029	$5.02	$178.00	$7.44	$6.86	$3.66	$0.52	$18.48	$196.48
Ausgrid - CLP1	$100.74	$6.70	1.042	$4.51	$111.95	$7.44	$6.86	$3.66	$0.75	$18.71	$130.66
Ausgrid - CLP2	$100.50	$6.70	1.042	$4.50	$111.70	$7.44	$6.86	$3.66	$0.75	$18.71	$130.41
Endeavour - CLP	$163.26	$6.54	1.047	$7.98	$177.78	$7.44	$6.86	$3.66	$0.84	$18.80	$196.58
Essential - CLP	$100.72	$6.26	1.029	$3.10	$110.08	$7.44	$6.86	$3.66	$0.52	$18.48	$128.56
Energex - NSLP	$150.91	$5.63	1.067	$10.49	$167.03	$7.44	$6.86	$0.00	$0.96	$15.26	$182.29
Energex - CLP1	$99.82	$5.63	1.067	$7.07	$112.52	$7.44	$6.86	$0.00	$0.96	$15.26	$127.78
Energex - CLP2	$106.65	$5.63	1.067	$7.52	$119.80	$7.44	$6.86	$0.00	$0.96	$15.26	$135.06
SAPN - NSLP	$189.87	$14.77	1.105	$21.49	$226.13	$7.44	$6.86	$3.19	$1.84	$19.33	$245.46
SAPN - CLP	$85.46	$14.77	1.105	$10.52	$110.75	$7.44	$6.86	$3.19	$1.84	$19.33	$130.08

Source: ACIL Allen analysis

Melbourne
Suite 4, Level 19; North Tower
80 Collins Street
Melbourne VIC 3000 Australia
+61 3 8650 6000

Canberra
Level 6, 54 Marcus Clarke Street
Canberra ACT 2601 Australia
+61 2 6103 8200

Sydney
Suite 603, Level 6
309 Kent Street
Sydney NSW 2000 Australia
+61 2 8272 5100

Perth
Level 12, 28 The Esplanade
Perth WA 6000 Australia
+61 8 9449 9600

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000 Australia
+61 7 3009 8700

Adelaide
167 Flinders Street
Adelaide SA 5000 Australia
+61 8 8122 4965

ACIL Allen Pty Ltd
ABN 68 102 652 148

acilallen.com.au