ACIL ALLEN

23 February 2022

Report to Australian Energy Regulator

Default Market Offer 2022-23

Wholesale energy and environment cost estimates for DMO 4 Draft Determination

About ACIL Allen

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

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

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

Suggested citation for this report

Default Market Offer 2022-23: Wholesale energy and environmental cost estimates for DMO 4 Draft Determination, ACIL Allen, February 2022

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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 2022-23 (DMO 4). These estimates are to be based on the relevant cost drivers for a retailer supplying electricity to residential and small business customers in non-price regulated jurisdictions (excluding Victoria).

This report provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination, using the methodology in our 2021-22 (DMO 3) Final Determination report to the AER, as well as considering stakeholder feedback in response to the AER's Options Paper, as well as feedback from the AER.

Summary of estimated energy costs

ACIL Allen's estimates of the 2022-23 total wholesale energy costs, environmental costs and total energy costs (TEC) for the Draft Determination for each of the regional tariff profiles are presented in Table ES 1.

Table ES 1 Estimated TEC components for 2022-23 Draft 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	$97.94	$17.73	$115.67
Endeavour - NSLP	$98.94	$17.86	$116.80
Essential - NSLP	$91.53	$17.61	$109.14
Ausgrid - CLP1	$64.04	$17.78	$81.82
Ausgrid - CLP2	$63.66	$17.78	$81.44
Endeavour - CLP	$91.11	$17.86	$108.97
Essential – CLP	$67.63	$17.61	$85.24
Energex – NSLP	$92.47	$14.09	$106.56
Energex – CLP31	$72.74	$14.09	$86.83
Energex – CLP33	$70.01	$14.09	$84.10
SAPN – NSLP	$128.26	$17.60	$145.86
SAPN – CLP	$67.78	$17.60	$85.38

Source: ACIL Allen analysis

The change, in $/MWh and percentage terms, in the estimated total energy costs between the 2021-22 DMO 3 Final Determination and 2022-23 DMO 4 Draft Determination are shown in Table ES 2 and Figure ES 1.

Table ES 2 Estimated TEC for 2022-23 ($/MWh, nominal) – Draft Determination

Profile	2021-22 Total energy costs at the customer terminal ($/MWh, nominal)	2022-23 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2021-22 to 2022-23 ($/MWh, nominal)	Change from 2021-22 to 2022-23 (%, nominal)
Ausgrid - NSLP	$107.11	$115.67	$8.56	7.99%
Endeavour - NSLP	$107.58	$116.80	$9.22	8.57%
Essential - NSLP	$99.38	$109.14	$9.76	9.82%
Ausgrid - CLP1	$79.66	$81.82	$2.16	2.71%
Ausgrid - CLP2	$76.69	$81.44	$4.75	6.19%
Endeavour - CLP	$102.60	$108.97	$6.37	6.21%
Essential - CLP	$86.34	$85.24	($1.10)	-1.27%
Energex - NSLP	$90.78	$106.56	$15.78	17.38%
Energex – CLP31	$75.59	$86.83	$11.24	14.87%
Energex – CLP33	$77.93	$84.10	$6.17	7.92%
SAPN - NSLP	$139.86	$145.86	$6.00	4.29%
SAPN - CLP	$93.21	$85.38	($7.83)	-8.40%

Source: ACIL Allen analysis

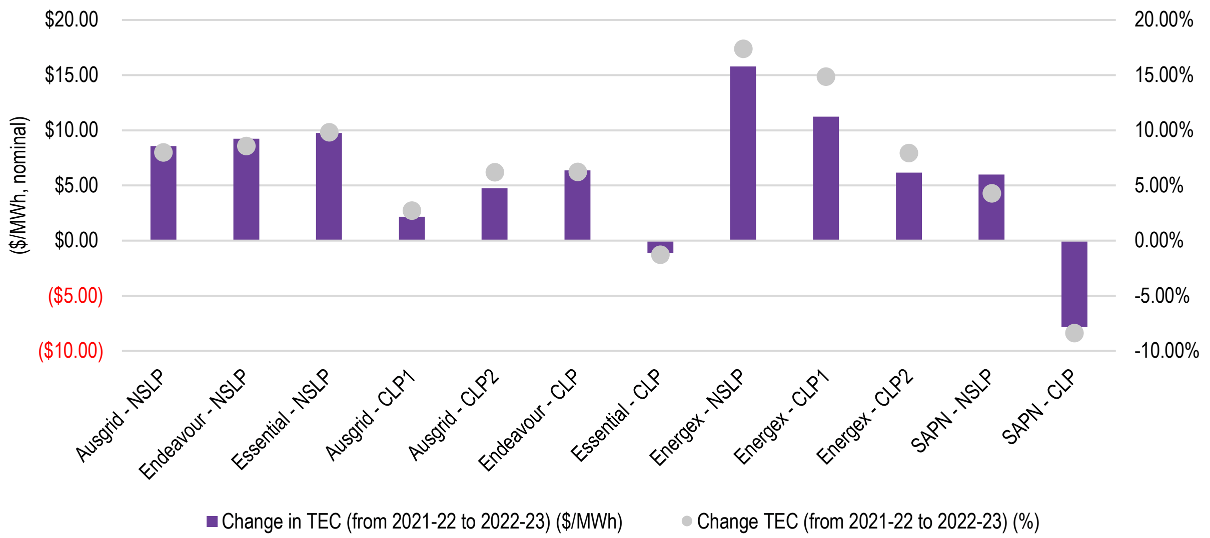
The change, in percentage terms, in the estimated energy cost components between the 2021-22 DMO 3 Final Determination and 2022-23 DMO 4 Draft Determination are set out in Table ES 3.

Table ES 3 Change in estimated energy cost components between 2021-22 and 2022-23 (%) – Draft Determination

Profile	Change in total wholesale energy cost (%)	Change in total environmental cost (%)	Change in total energy cost (TEC) (%)
Ausgrid - NSLP	11.37%	-7.51%	7.99%
Endeavour - NSLP	12.09%	-7.51%	8.57%
Essential - NSLP	13.93%	-7.51%	9.82%
Ausgrid - CLP1	5.96%	-7.49%	2.71%
Ausgrid - CLP2	10.77%	-7.49%	6.19%
Endeavour - CLP	9.39%	-7.51%	6.21%
Essential - CLP	0.49%	-7.51%	-1.27%
Energex - NSLP	24.91%	-15.88%	17.38%
Energex – CLP31	23.62%	-15.88%	14.87%
Energex – CLP33	14.43%	-15.88%	7.92%
SAPN - NSLP	7.36%	-13.68%	4.29%
SAPN - CLP	-6.92%	-13.68%	-8.40%

Source: ACIL Allen analysis

Figure ES 1 Change in estimated TEC between 2021-22 and 2022-23 ($/MWh, and %) – Draft 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 2021-22, futures base contract prices for 2022-23, on an annualised and trade weighted basis to date, have:
    - increased by about $6.90/MWh for Queensland
    - increased by about $4.00/MWh for New South Wales
    - decreased by about $6.90/MWh for South Australia.
  - Cap contract prices for 2022-23 have increased noticeably compared with 2021-22, and on an annualised and trade weighted basis to date, have:
    - increased by about $5.70/MWh for Queensland
    - increased by about $4.20/MWh for New South Wales
    - increased by about $3.80/MWh for South Australia.
  - Unlike the previous two DMOs in which there was a clear decline in contract prices, the market is now expecting an increase in price outcomes as the amount of utility scale renewable investment coming on-line slows between 2021-22 and 2022-23 (compared with recent years), coupled with the closure of Liddell in New South Wales, Torrens Island A in South Australia, the continued unavailability of Callide C Unit 4 for at least half of 2022-23, and stronger coal and gas prices.
  - Further, cap contract prices have increased substantially for 2022-23 compared with 2021-22. This may reflect a degree of uncertainty faced by providers of caps around the ability of their peaking plant to cover price spikes in the spot market under five-minute settlement (5MS), as well as an expectation of an increase in underlying price volatility. A $1/MWh increase in cap price can increase the WEC for a NSLP by about $3/MWh, all other things equal, due to the peaky shape of the NSLP.
  - This is further exacerbated by the expected continued strong uptake of rooftop PV which carves out the demand during daylight hours, 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 at current base contract prices.

  - **Other energy costs (a sub-component of total wholesale energy cost):** the most significant change in other wholesale energy costs are the costs associated with ancillary services recovery in Queensland. Ancillary service costs are estimated by the most recent 52 weeks of actual cost data as published by AEMO. There has been a noticeable increase in weekly ancillary service costs in Queensland over the past two quarters as a result of upgrade works associated with the QNI giving rise to price separation between the two regions. Direction costs in South Australia have also increased as a result of very low spot prices during daylight hours and increased gas prices reducing the amount of synchronous generation below required levels. It is expected that direction costs in South Australia will decrease now that the newly installed synchronous condensers have completed their commissioning phase, and AEMO reduces the minimum requirement of the continuous operation of gas-fired units from four two to ensure power system security.
- **Environmental costs:** environmental costs are estimated to fall across all regions. The decline is primarily driven by a projected decline in the cost of the SRES between 2021-22 and 2022-23. Although there is an expectation that small-scale installations in 2022 and 2023 will remain at similar levels observed in 2021, the cost of the scheme decreases due to the shortening of the deeming period. This may change when the CER releases its binding STP for 2022. The cost of the LRET in 2022-23 is very similar to 2021-22. 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 2022-23 (DMO 4).

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

This report provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination for DMO 4, using the methodology in our 2021-22 (DMO 3) Final Determination report to the AER, as well as considering stakeholder feedback in response to the AER's Options Paper.

The report is presented as follows:

— Chapter 2 summarises our methodology.

— Chapter 3 provides responses to submissions made by various stakeholders following the release of the AER's *Default Market Offer prices: Options Paper on the methodology to be adopted for the 2022-23 determination (and subsequent years)* (25 October 2021), 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.

— Finally, Appendix A summarises our high-level comparison with the AEMC's 2021 Residential Electricity Price Trends Report released in November 2021.

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 4, including refinements based on stakeholder feedback from the Options 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 of the following components (as shown in Figure 2.1):

— Wholesale energy costs (WEC) for various demand profiles

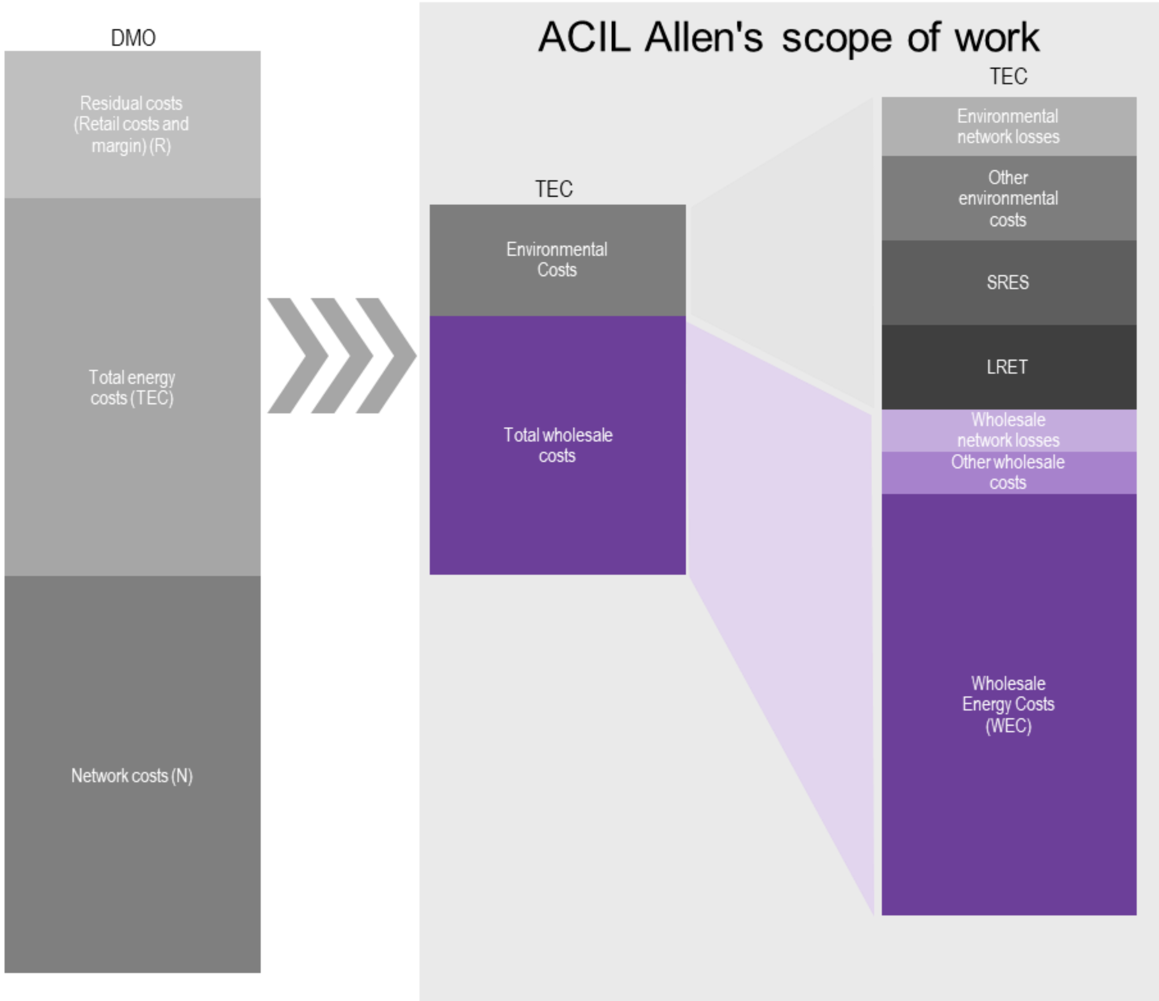
— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET).

— Other wholesale costs: including National Electricity Market (NEM) fees, ancillary services charges, Reliability and Emergency Reserve Trader (RERT) costs, and costs of meeting prudential requirements.

— 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 4 (and DMO 2 and 3) 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:

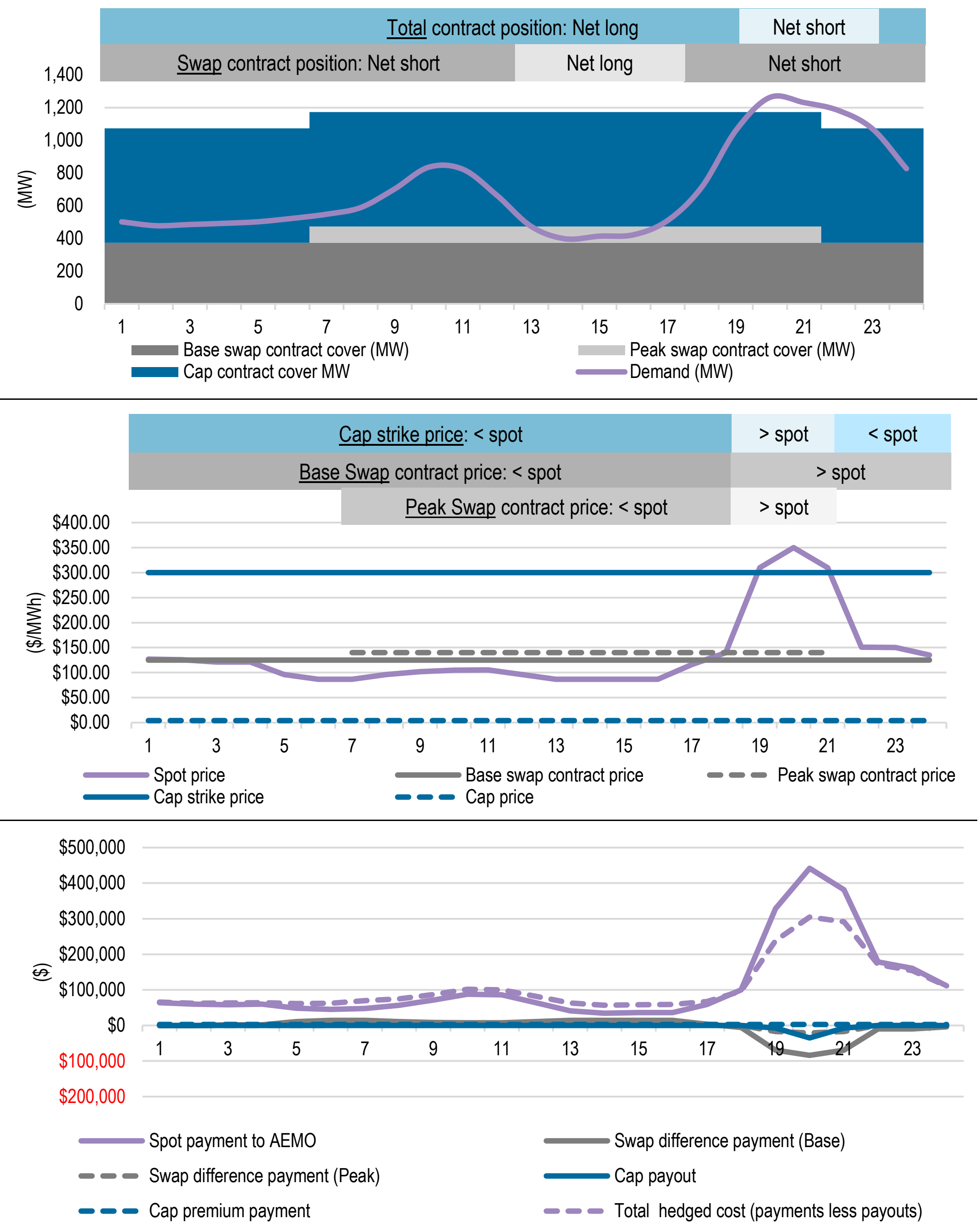
— Pays AEMO the spot price multiplied by the demand.
— Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract 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. 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.

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	NSLP	NSLP,INTEGRAL	MSATS
	Endeavour	CLP	CLOADNSWIE,INTEGRAL	MSATS
	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
	SAPN	NSLP	NSLP,UMPLP	MSATS

Source: AEMO

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 previous determinations, ACIL Allen has 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 Draft Determination, 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[1] 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). Further, the strategy has not been altered in response to the AER adopting the 75th percentile WEC.

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 (ESOO) published by AEMO and take into account past trends and relationships between the NSLPs and the corresponding regional demand.

[1] 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.

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.

Supply side settings

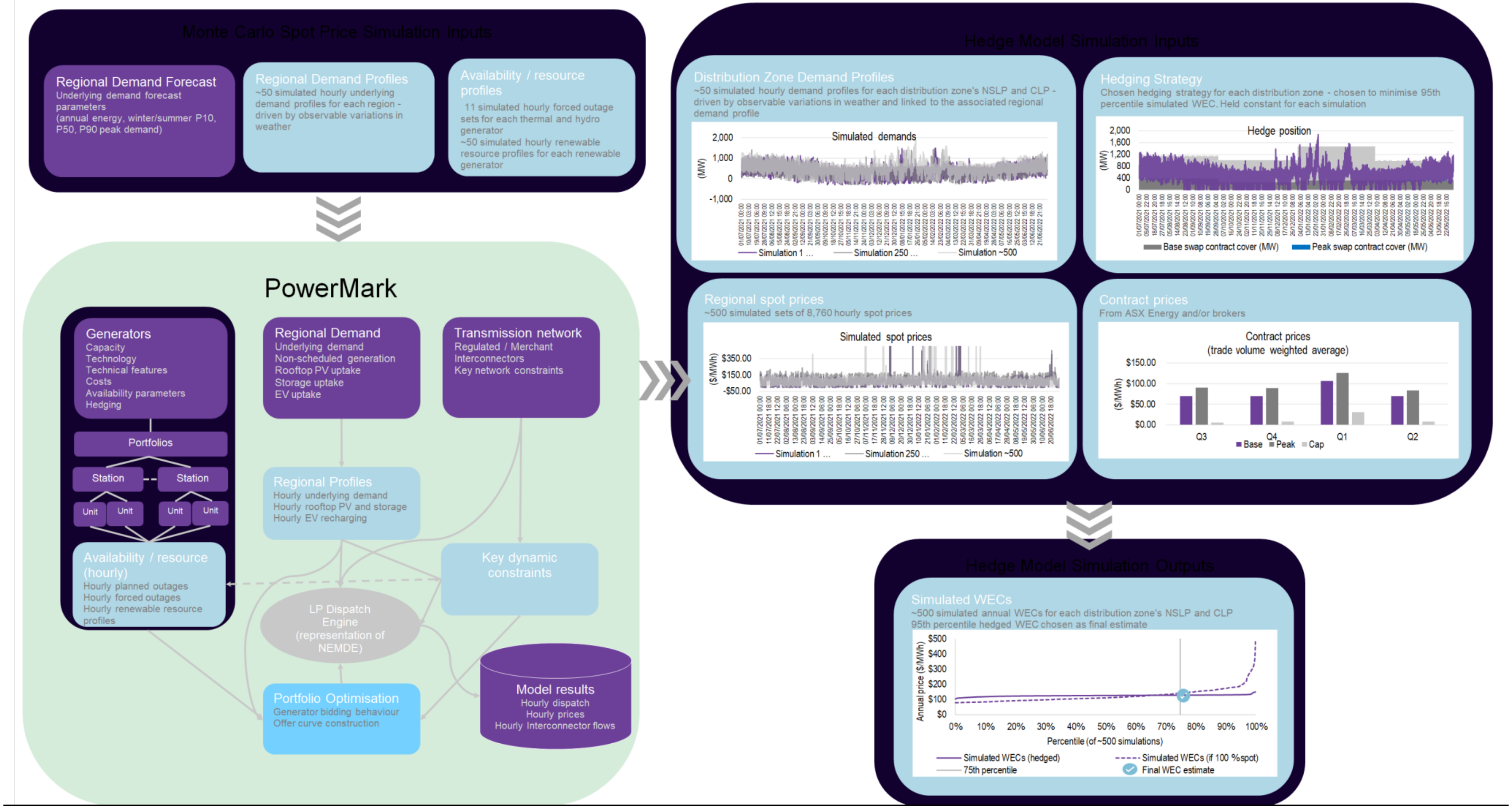
ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2022-23 we use our December 2021 Reference case projection settings which are closely aligned with AEMO's Integrated System Plan (ISP) for the Draft Determination, and we will use our latest reference case available at the time for the Final Determination.

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.

Summary infographic of the approach to estimate the WEC

Figure 2.3 provides an infographic type summary of the data, inputs, and flow of the market-based approach to estimating the WEC.

Figure 2.3 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.

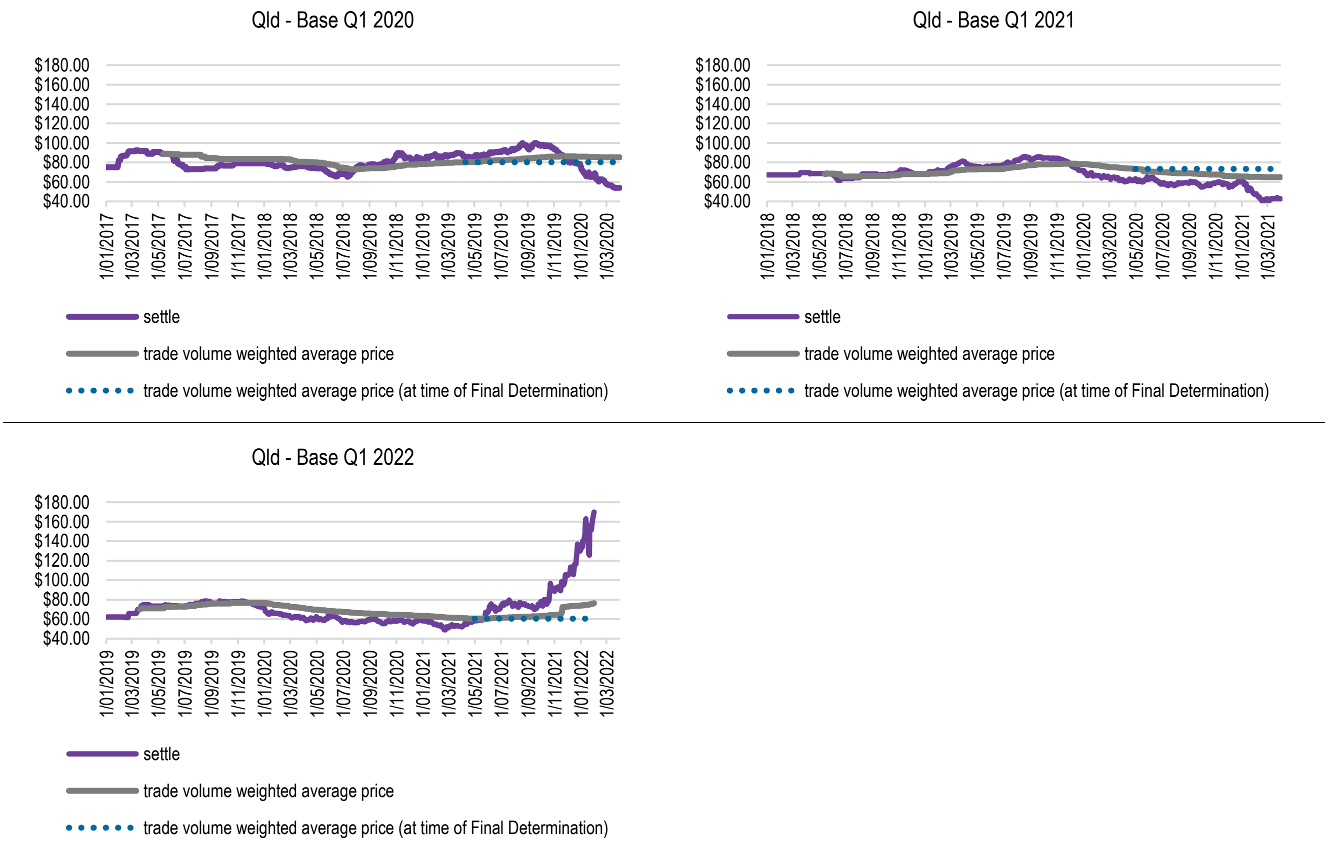
Contract prices are a key driver of the WEC estimate. In some years, contract prices may increase after the Final Determination is made, in other years they may decrease, and in some cases, they may remain relatively stable. Figure 2.4 provides three examples of this phenomenon for quarter one base contracts in Queensland over the past three 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).

Figure 2.4 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 2.4 demonstrate a number of important points about the WEC estimation methodology:

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

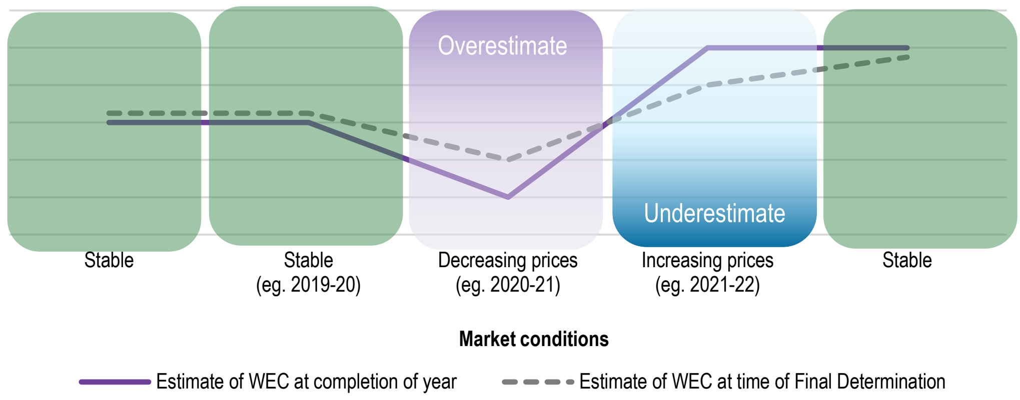
— It is much more challenging to estimate the WEC during periods of increasing or decreasing contract prices.

— 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.

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 2.5.

Figure 2.5 Illustrative comparison of WEC estimation accuracy given market environment



Source: ACIL Allen

2.3.2 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 used for estimating market fees makes use of AEMO's budget report.

It is worth noting that for DMO 1 and 2, the National Transmission Planner (NTP) was included in this cost category. However, the recovery of this item has been transferred from AEMO to each of the Transmission Network Service Providers (TNSPs) directly, forming part of the TUOS charge. Therefore, the NTP cost is excluded from our analysis for 2022-23, just as it was for 2021-22.

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 current money market rate is 0.10 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 had triggered the RRO in South Australia for the first quarter of 2023, however, this was revoked in October 2021.

The RRO is currently not triggered for 2022-23, and hence we are not required to account for the RRO in the wholesale costs for 2022-23. However, it is worth noting that this cost component should be included as part of the wholesale cost if the RRO is triggered in the future.

We think that entering into a mix of firm base, peak, 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.

In the case of South Australia, the adopted hedging strategy already assumes a cover of 100 per cent of the P50 peak demand in each quarter. Hence, if the RRO was to be reinstated for the January to March 2023 quarter, then no further changes would be required to 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[2].

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 Draft Determination) and divided by the corresponding annual regional customer energy.

2.3.3 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

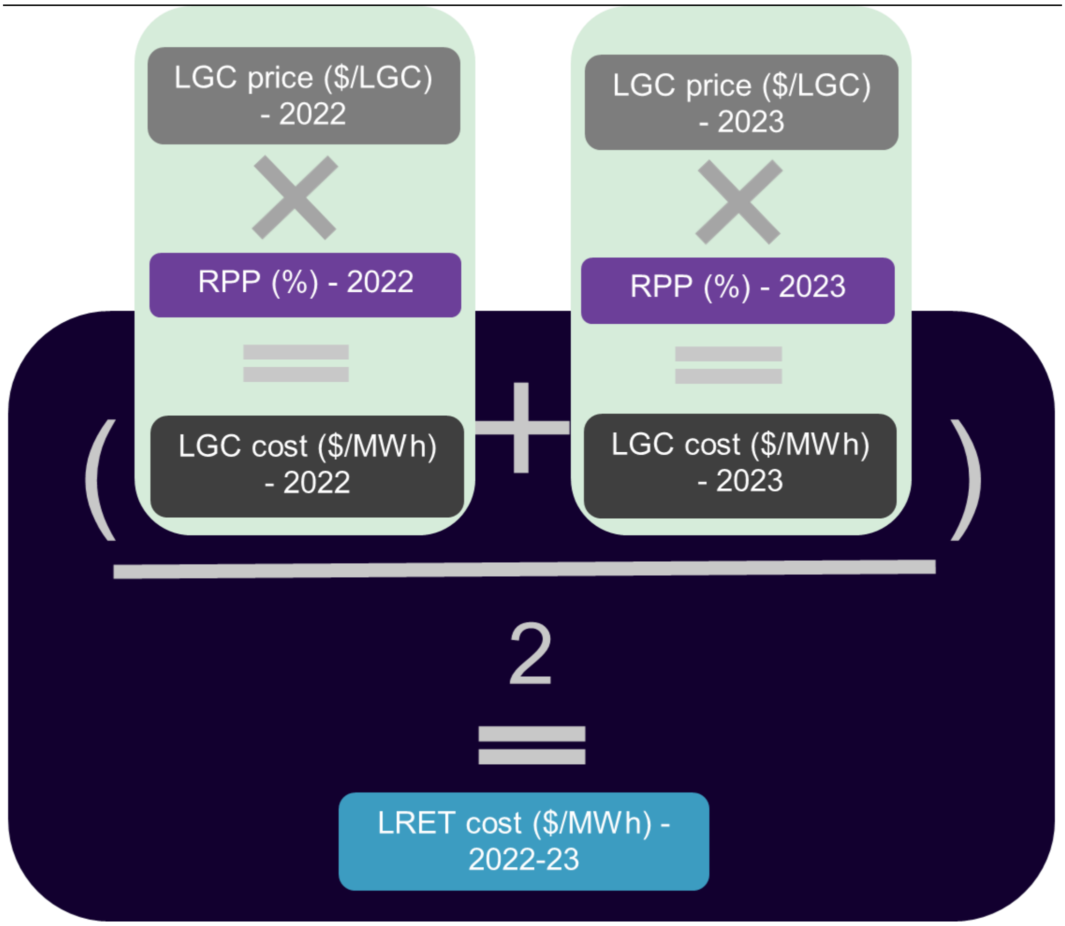
[2] https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2015/direction-recovery-reconciliation-file-v13.pdf

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 2022-23, ACIL Allen uses the following elements:

— The average of the trade-weighted average of LGC forward prices for 2022 and 2023 from brokers TFS
— the Renewable Power Percentages (RPPs) for 2022, published by the CER
— estimated RPP values for 2023[3].

Figure 2.6 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 a 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.

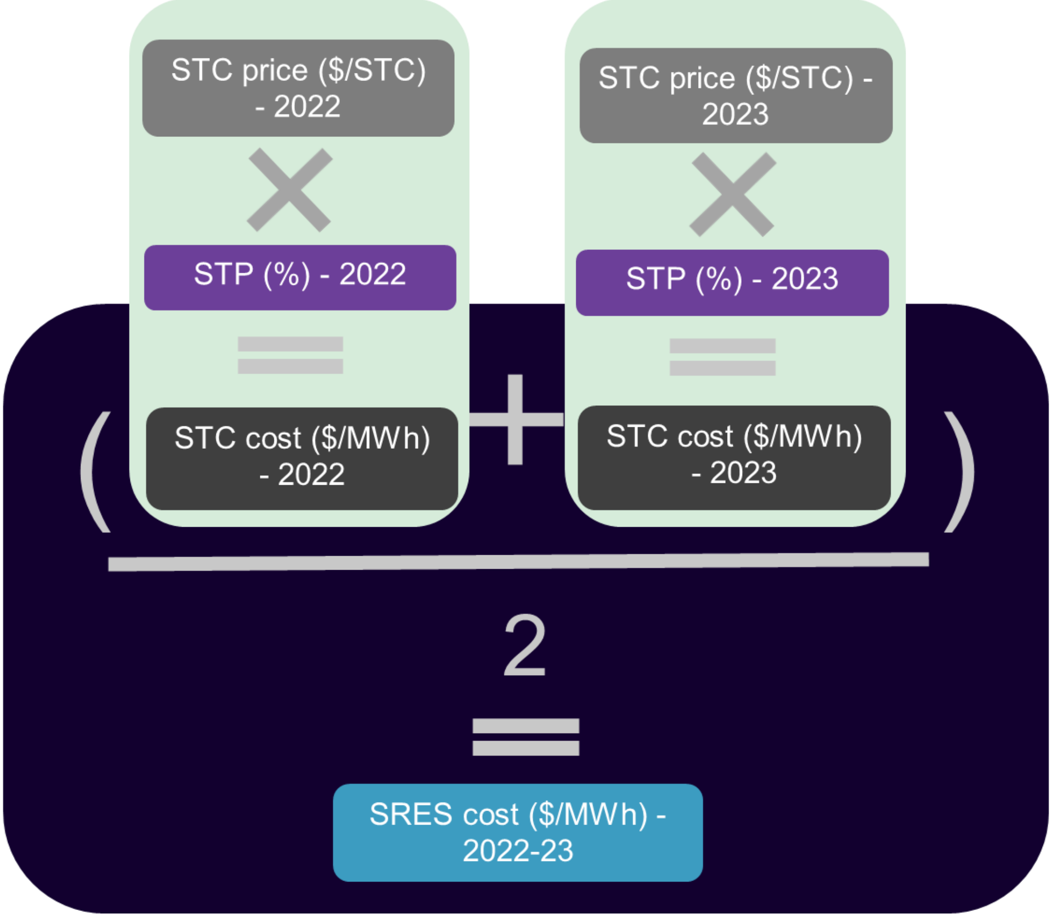
The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

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

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

— the binding Small-scale Technology Percentage (STP) for 2022 published by the CER
— an estimate of the STP value for 2023[4]
— CER clearing house price[5] for 2022 and 2023 for Small-scale Technology Certificates (STCs) of $40/MWh.

Figure 2.7 Steps to estimate the cost of SRES



Source: ACIL Allen

2.3.4 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:

[4] The STP value for 2023 is estimated using estimates of STC creations and liable acquisitions in 2023, taking into consideration the CER's non-binding estimate.

[5] 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.

— Energy Savings Scheme Target for 2022 and 2023 of 9 and 9.5 per cent respectively, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2022 and 2023 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 commences 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 2022-23 of 0.5 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 in previous DMOs.

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. We propose to use this data when estimating the cost of the REPS in future determinations.

In the AEMC's 2020 price trends report, the cost of the REPS is assumed to be the same as the cost of the REES in previous years. The estimated cost is $2.50/MWh.

In the AEMC's report, the estimated cost of REPS, which is expected to be generally flat in nominal terms over the reporting period, comprises less than 10 per cent of the cost of environmental policies, and less than one per cent of the total retail bill in South Australia during the four-year reporting period.

Given the limited availability of public data on the cost of meeting the REPS at this point in time and given that the cost as estimated by AEMC is a very small component of the overall cost of the retail bill, ACIL Allen uses the estimates of the cost of REPS provided in the latest AEMC price trends report.

2.3.5 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[6], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

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

Given the timing of the Draft and Final Determinations tends to straddle AEMO's release dates of their MLF and DLF, the estimated losses for the Draft Determination are invariably equal to the losses from the previous year's Final Determination, and are then updated for the Final Determination upon release of AEMO's updated reports. Hence, the MLFs used to estimate losses for the Draft Determination for 2022-23 are set to equal the losses from the 2021-22 Final Determination.

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

Responses to submissions to Options Paper 3

The AER forwarded to ACIL Allen a total of 16 submissions in response to its Options Paper. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration. A summary of the review is shown below in Table 3.1.

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

— Contract prices used in the hedge model
— Hedge book build up and hedging strategy
— Use of the 95th percentile simulated WEC
— Price shape
— Load shape
— AEMO Directions costs
— Estimating environmental costs.

Table 3.1 Review of issues raised in submissions in response to Options Paper

ID	Stakeholder	Wholesale energy costs	Contract prices /hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
1	Australian Energy Council	Nil	Nil	Nil	Nil	Nil	Nil
2	AGL	Nil	Yes	Nil	Yes	Nil	Nil
3	Alinta	Nil	Nil	Nil	Nil	Nil	Nil
4	Ausgrid	Nil	Nil	Nil	Nil	Nil	Nil
5	Energy Consumers Australia	Yes	Nil	Nil	Nil	Nil	Nil
6	EnergyAustralia	Nil	Nil	Yes	Nil	Nil	Nil
7	Enova	Yes	Yes	Yes	Nil	Nil	Nil
8	Momentum Energy	Nil	Nil	Nil	Nil	Nil	Nil
9	Origin	Nil	Nil	Nil	Nil	Nil	Nil
10	Public Interest Advocacy Centre	Nil	Nil	Nil	Nil	Nil	Nil
11	Powershop	Yes	Nil	Nil	Nil	Nil	Nil
12	Red Energy and Lumo Energy	Nil	Nil	Nil	Nil	Nil	Nil
13	SACOSS	Yes	Yes	Nil	Nil	Nil	Nil
14	SA Department of Energy and Mining	Nil	Nil	Nil	Nil	Nil	Nil
15	Simply Energy	Nil	Nil	Nil	Nil	Nil	Nil
16	Tango Energy	Nil	Nil	Nil	Nil	Nil	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 3 to estimate the wholesale and environmental costs for DMO 4, these include:

— AEC
— AGL
— Alinta
— Energy Australia
— Enova
— Origin
— Red Energy and Lumo Energy
— South Australian Department of Energy and Mining
— Simply Energy.

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

3.2 Contract prices used in hedge model

AGL on page five of its submission notes that factors such as increases in rooftop PV penetration, negative pricing intervals, and AEMO directions to gas fired generators to dispatch to maintain system security, are some factors which have resulted in an illiquid forward contract market in South Australia. As a consequence, AGL suggest that the prices for traded contracts reported by ASX Energy are not representative of what it costs retailers to manage risk in South Australia, particularly in relation to cap products. AGL suggest the AER consider alternative benchmarks.

As noted in previous DMO determinations, ACIL Allen continues to benchmark the ASX Energy contract data with broker data. Trade prices from the broker data for swaps and caps align almost perfectly with ASX Energy data. ACIL Allen does not have access to other benchmarks.

ACIL Allen notes the lower trade volumes for cap products in South Australia compared with New South Wales and Queensland in absolute terms. However, when accounting for the relative size of the three regions in terms of peak demand, the volume of cap trades to date for 2022-23, when expressed as a percentage of the peak demand, for South Australia is comparable with the other regions.

We also account for the lower degree of certainty that may be associated with lower trade volumes by adopting the 95th percentile WEC[7] (see section 3.5).

[7] However, for this determination the 75th percentile WEC is reported.

Figure 3.1 Cumulative trade volumes of 2022-23 cap contracts expressed as a percentage of the peak demand by region as of 11 January 2022

Note: Trade volumes tend to increase by between 50 and 100 per cent between Draft Determination and Final Determination – particularly for the latter two quarters of the determination period.

Source: ACIL Allen analysis of ASX Energy data and AEMO ESOO

3.2.1 ACIL Allen recommendation

In the absence of a proposed alternative method based on transparent information, including additional hedge products, ACIL Allen is of the view that the current approach of using ASX Energy trade data, benchmarked with broker data, to estimate hedge costs remains appropriate.

3.3 Hedge book build up

AGL, Alinta, Enova, Origin, the South Australian Department of Energy and Mining, and Simply Energy in their submissions support the continuation of the current approach of building up the hedge book using data from the date of the first observed trade for each contract product for a given quarter and region.

SACOSS on page eight of its submission suggests that a shorter book build period be adopted when wholesale prices are in decline. We note that taking this approach will result in a more noticeable decline in WEC. However, in our view the approach ought to be consistent regardless of the underlying trend in wholesale price outcomes – otherwise the approach would quite rightly be characterised as cherry picking. A shorter book build period during periods of increasing wholesale price outcomes will result in a more noticeable increase in WEC.

In other words, the current approach of extending the book build period by using all available trade data increases the chance to reducing oscillations in the WEC from one determination to the next – as noted by some of the other submissions in support of the current approach.

3.3.1 ACIL Allen recommendation

ACIL Allen remains of the view that using all available trade data from ASX Energy to estimate contract prices is appropriate.

3.4 Hedging strategy

AGL, Alinta, Origin, and Simply Energy in their submissions support the continuation of the current approach of choosing a risk averse hedging strategy that minimises the 95th percentile WEC.

SACOSS state on page eight of its submission that it is in favour of adopting a less risk averse hedging strategy during periods of declining wholesale price conditions.

ACIL Allen maintains the view that retailers are unlikely to fundamentally change their hedging strategy simply because the market is experiencing or expected to experience low price conditions.

3.4.1 ACIL Allen recommendation

ACIL Allen remains of the view that adopting a risk averse strategy is appropriate.

3.5 Use of the 95th percentile simulated WEC

AGL, Alinta, Origin, and Simply Energy in their submissions support the continuation of the current approach of using the 95th percentile simulated WEC as the final estimate of the WEC. Enova in its submission considered the 75th percentile more appropriate, and Energy Consumers Australia considered the 50th percentile more appropriate. ACIL Allen notes this issue was raised in DMO 3, in which no submissions were received in favour of changing the choice of percentile.

Enova on page four of its submission suggest that:

Subject to the hedging strategy remaining 'risk averse', i.e., minimising the spot cost, the WEC estimate could well be 75th percentile. From the consumers' perspective it doesn't sound reasonable that the retailer can account nearly the worst-case costs year after year.

Energy Consumers Australia on page seven of its submission suggest:

It makes sense to use the 50th percentile as any under or over performance of assumed DMO costs should be balanced by an effective hedging strategy.

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.

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.

3.5.1 ACIL Allen response

The AER has requested ACIL Allen to present the 75th percentile WEC for this Draft 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.

3.6 Price shape

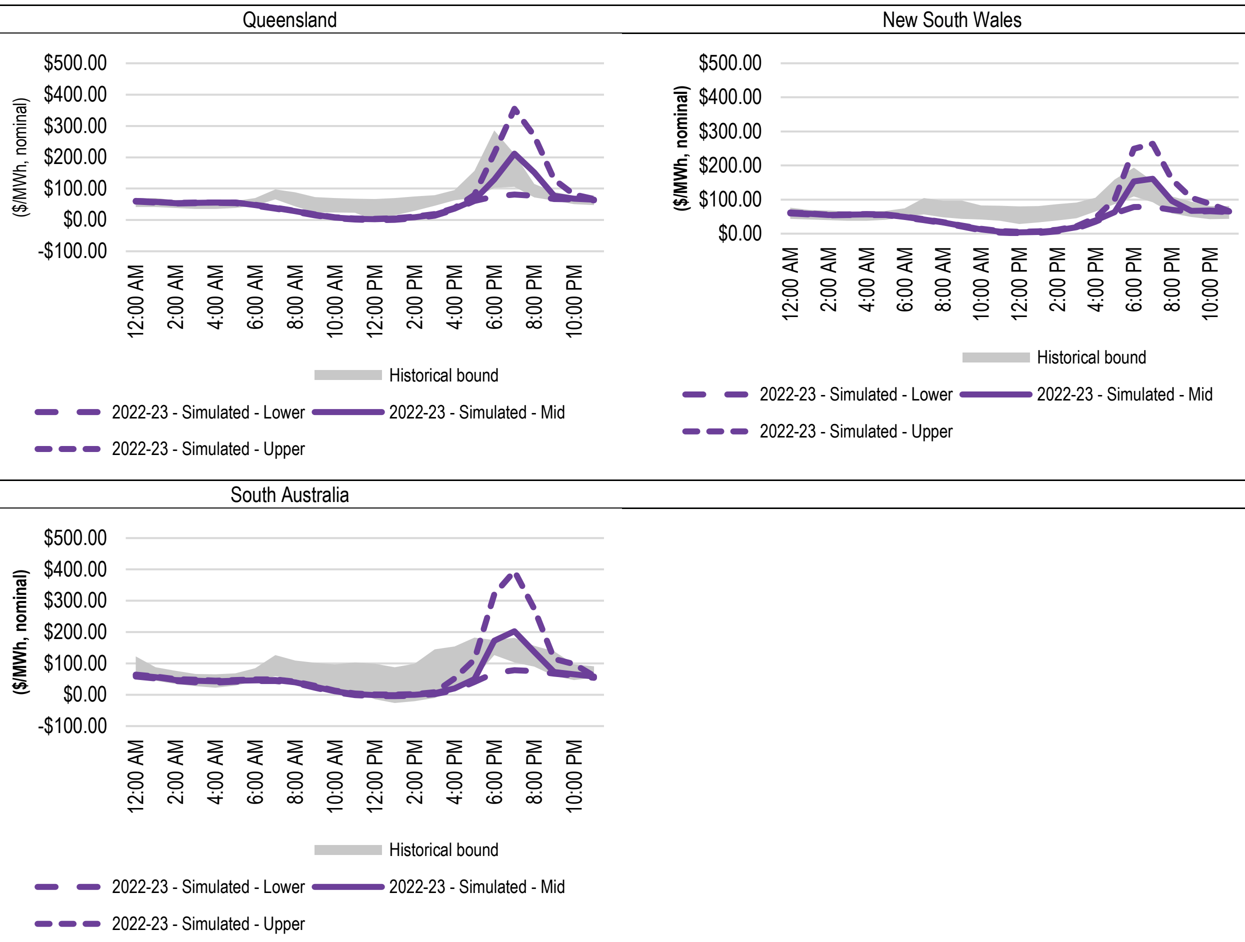
Powershop on page three of its submission appears to be of the view that the shape of modelled spot prices does not reflect what is occurring in the market:

Powershop believes the modelling for the price shape can be drastically improved for it currently does not take into account the difference in price shape the market has seen more recently, and have not factored this into their forecast.

We assume Powershop's reference to price shape relates to the continued reduction in spot price outcomes during daylight hours due to the continued uptake of rooftop PV, and commissioning of utility scale PV.

The methodology takes into account the assumed uptake of rooftop PV, and commissioning of committed new utility scale PV, driving the change in price shape as shown in Figure 3.2. The modelling suggests further downward pressure on spot price outcomes during daylight hours compared with recent history, and an increase in negative or zero price outcomes.

Figure 3.2 Simulated average time of day spot price ($/MWh, nominal) for Queensland, New South Wales, and South Australia for 2022-23 compared with range of actual annual outcomes in past five years



Source: ACIL Allen analysis, and AEMO data

3.7 Load shape

Powershop on page three of its submission make some general comments about load shape, including noting the use of the NSLP remains appropriate.

However, Powershop appears to assert that that we are of the view that the load shape of residential and small business customers is the same, or the load shapes of residential consumers on accumulation and interval meters are the same.

This is not the case at all. In our report to the Draft Determination of DMO 3, we noted the difference in load shape between residential and small business customers based on the interval meter data provided to us, and that although there were similarities in the load shape of residential consumers on accumulation and interval meters there were some notable differences for particular distribution networks.

In our view, the key issue to be considered in the future in relation to load shape is whether using the NSLP remains valid when interval meter penetration breaches a particular threshold, or whether both the NSLP and interval meter data ought to be combined. At this stage, ACIL Allen has not been asked by the AER to report WEC estimates using interval meter data. However, the methodology can be readily adapted to do so in the future.

3.8 AEMO Direction costs

AGL acknowledges the AER's acceptance that AEMO Direction costs ought to be included in the DMO.

3.8.1 ACIL Allen recommendation

Given the AER's acceptance of the inclusion of Direction costs in the DMO, ACIL Allen will estimate these costs using the methodology outlined in section 0.

3.9 Environmental costs

AGL and Origin are generally comfortable with the current approach of estimating environment costs. AGL notes it would need to revisit this if the cost build-up approach is adopted more broadly for the DMO – however, no further detail is provided.

Enova on page two of its submission raised whether using more than one broker would improve the estimated costs, and whether PPA price information should be used.

When comparing the TFS price data with other price data in the public domain (such as data shown in https://www.demandmanager.com.au/certificate-prices/) there is very strong agreement between traded prices. It is unlikely that additional broker data will improve the estimates.

ACIL Allen has provided its justification for not using non-transparent and long-dated PPA data to estimate LGC prices in its methodology papers and determination reports for DMO 2 and 3.

3.9.1 ACIL Allen recommendation

ACIL Allen maintains the view that a market-based approach using contemporary forward LGC prices represents most reliable indicator of the current market consensus view of the price of LGCs in the near-term. This is also consistent with a market-based approach for wholesale electricity costs.

ACIL Allen is of the view that no further consideration is required on this matter, and recommends no change be made to the LRET cost estimation methodology for DMO 4.

3.10 Extended period to estimate RERT and Ancillary Service costs

Enova on page two of its submission proposes the use of the latest 24-36 months of weekly cost data to estimate the RERT and ancillary service costs, rather than the current approach of using the latest 12 months of weekly cost data. Enova note this would reduce the variation in these cost components from one DMO to the next.

This alternative approach would reduce volatility in these components, however, it is inconsistent with the approach used for every other cost component.

Although the estimation of contract and LGC prices utilises contract trade data since the date the products were first traded, which may extend beyond 12 months in the past, they relate to the contract and LGC products of the year of the given DMO, and not products from earlier years.

3.10.1 ACIL Allen recommendation

ACIL Allen notes that although the costs associated with the RERT and ancillary services can change from one year to the next, they represent a relatively small portion of the overall DMO.

Hence, we recommend not making a change to the estimation methodology for costs associated with the RERT and ancillary services, to maintain consistency with the estimation horizon used for other cost components.

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 2022-23.

4.1.1 Historic demand and energy price levels

Figure 4.1 to Figure 4.3 show the average time of day pool (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 10 years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the profiles.

It is worth noting the uplift in spot prices between 2014-15, and 2016-17, across most periods of the day. During this period, wholesale spot prices increased by about $40/MWh in New South Wales and Queensland, and by about $60/MWh in South Australia. This was a result of coal station closures (Wallerawang in New South Wales in 2014, Northern in South Australia in 2016, and Hazelwood in Victoria in 2017), an increase in the underlying demand in Queensland due to the ramping up of production associated with the LNG export facilities in Gladstone, as well as an increase in gas prices into gas fired generators across the NEM, and an increase export coal prices in New South Wales and Queensland, as well as coal supply constraints into coal fired power stations in New South Wales.

Between 2016-17 and 2018-19 annual average prices remained reasonably flat in New South Wales and South Australia and reduced slightly in Queensland in 2017-18.

Compared with 2018-19, wholesale spot prices in 2019-20 decreased by about $27/MWh in Queensland, decreased by about $17/MWh in New South Wales, and decreased by about $45/MWh in South Australia. This was largely a result of the continued commissioning of large-scale renewable generation across the NEM, as well as a decline in gas prices due to a slightly better global supply outlook, which meant LNG exporters made more supply available to the domestic market due to depressed international prices.

In 2020-21, annual wholesale spot reduced by about $7/MWh and $17/MWh in New South Wales and South Australia respectively – mainly due to lower coal and gas prices and the continued commissioning of large-scale renewable generation across the NEM. In Queensland, 2020-21 prices were generally lower than in 2019-20 up until the last six weeks of the financial year when Callide C unit 4 suffered a critical outage in May 2021 which resulted in multiple coal fired power station units tripping in Queensland. A consequence of this incident was an increase in price volatility due to lower levels of plant availability, which resulted in the annual wholesale spot price being by about $10/MWh higher than that of 2019-20.

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Prices in New South Wales and South Australia in 2021-22 have increased by about $8/MWh when compared with 2020-21 – driven by increasing coal and gas prices driving up overnight and peak prices which more than offsets a reduction in prices during daylight hours due to further uptake of rooftop PV.

Prices in Queensland for 2021-22 to date have increased by about $30/MWh when compared with 2020-21. This is despite the continued uptake of rooftop PV reducing price outcomes during daylight hours. The main reason for the increase in prices overall is the continued outage of Callide C Unit 4 (which is not expected to return until the end of 2022 at the earliest), an increase in export coal prices, and an increase in gas prices.

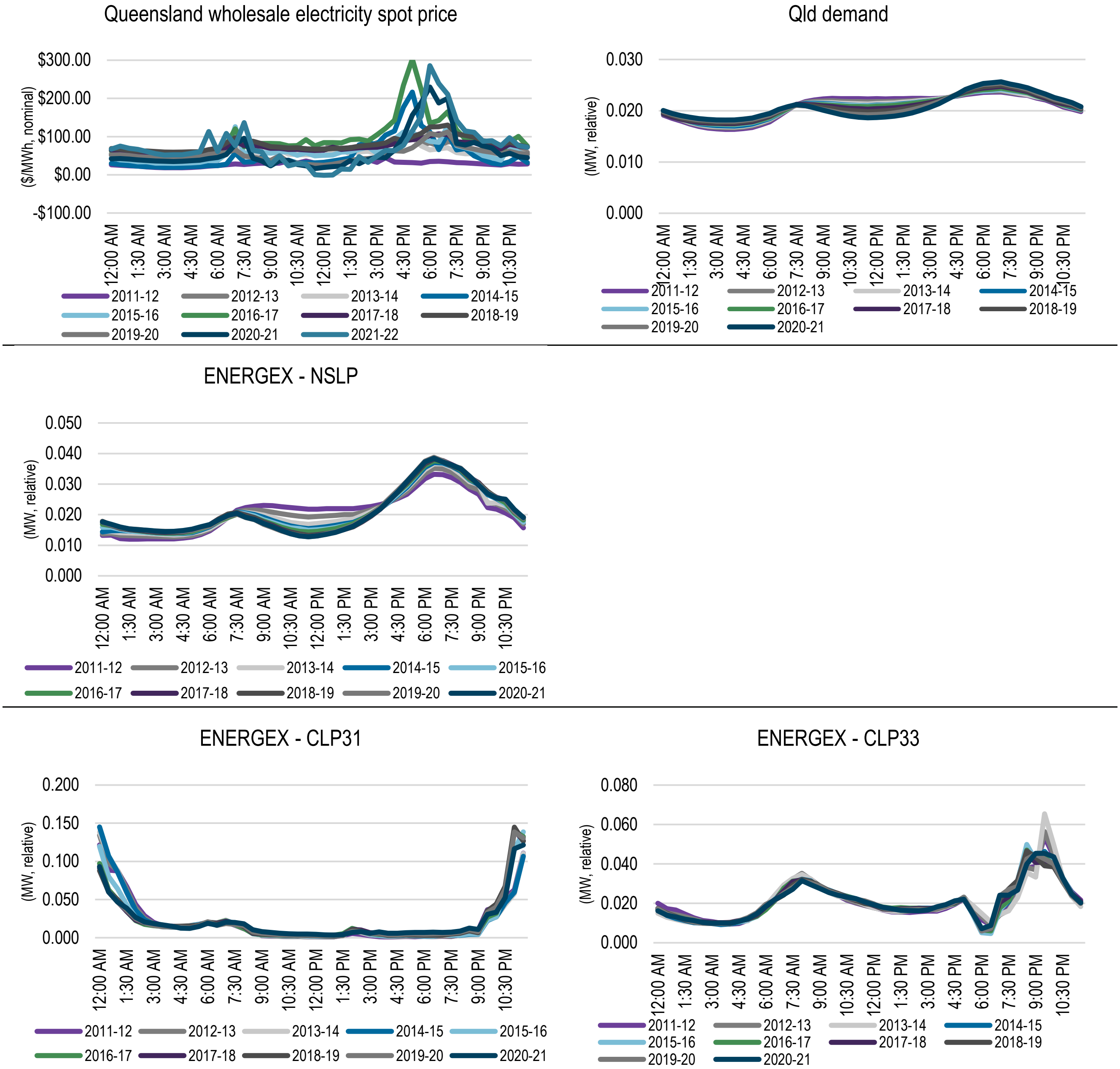
Over the past seven or so years, the Queensland, and particularly the South Australian, NSLP load profiles, and to some degree, the New South Wales NSLPs, have experienced a carving out of load during daylight hours with the increased penetration of rooftop solar PV. This results in the load profile becoming peakier over time and consequently, the demand weighted spot prices[8] (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 (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.

Although the increased penetration of rooftop PV is placing downward pressure wholesale spot prices during daylight hours, price volatility during the evening peak has persisted. Indeed, it has increased in 2021-22 to date due to increased gas prices (and the outage at Callide C in Queensland). The carving out of the NSLPs during daylight hours increases the relative weighting of the load profile during the higher priced evening peak and reduces the relative weighting during the lower priced daylight hours.

However, over the past few years the rate of carve out 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.

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

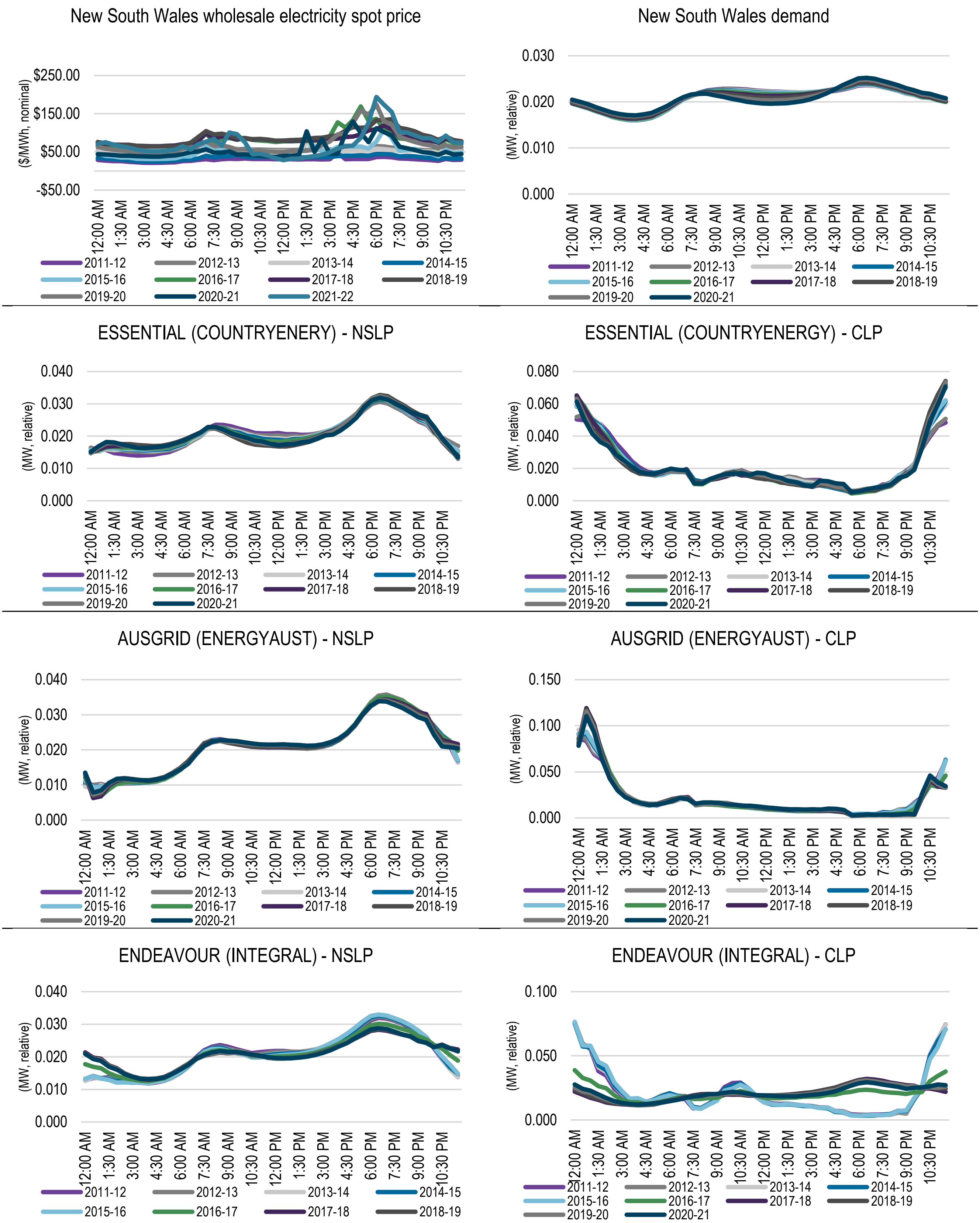
Figure 4.1 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2011-12 to 2020-21



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. 2021-22 price series includes data up to November 2021.

Source: ACIL Allen analysis of AEMO data

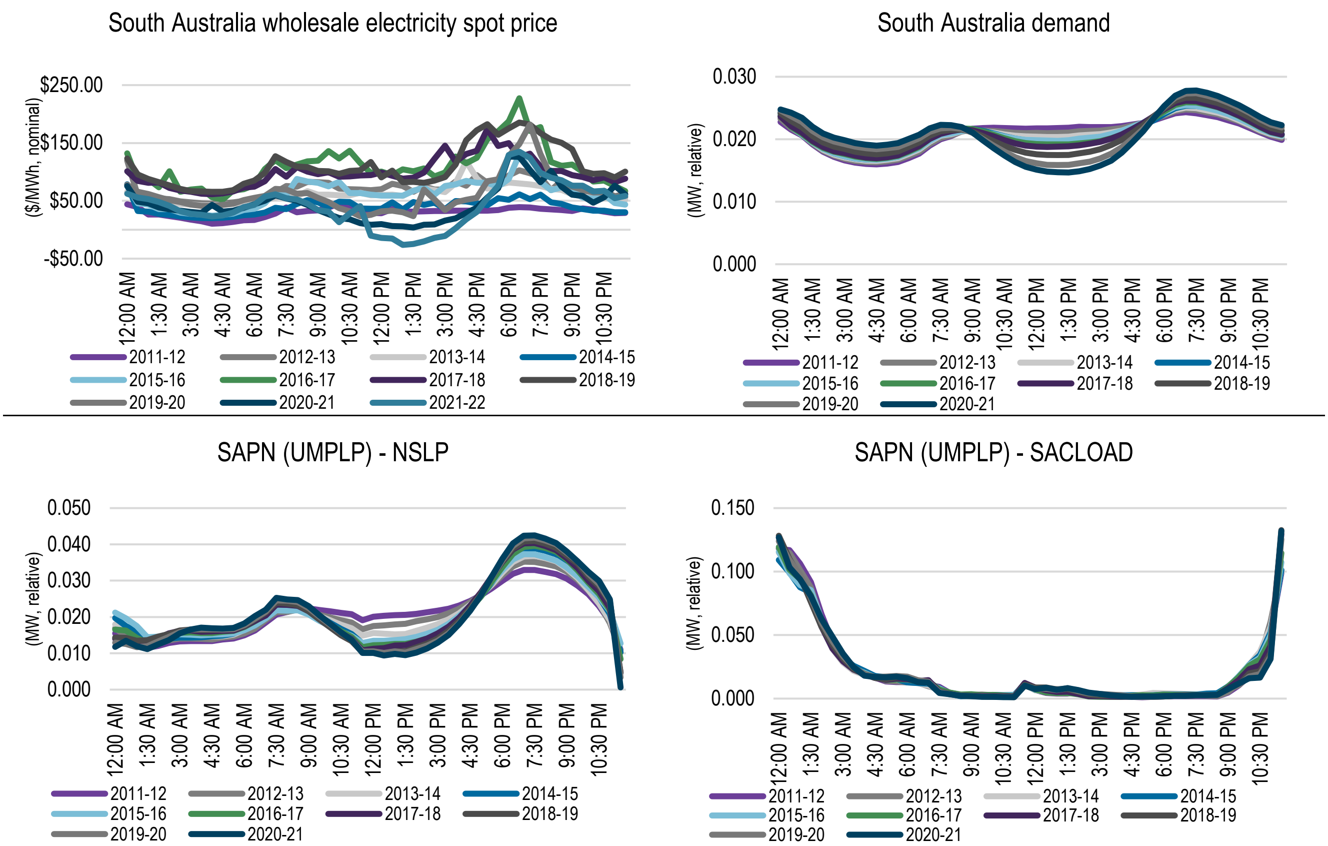
Figure 4.2 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – New South Wales – 2011-12 to 2020-21



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. 2021-22 price series includes data up to November 2021.

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 2020-21



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. 2021-22 price series includes data up to November 2021.

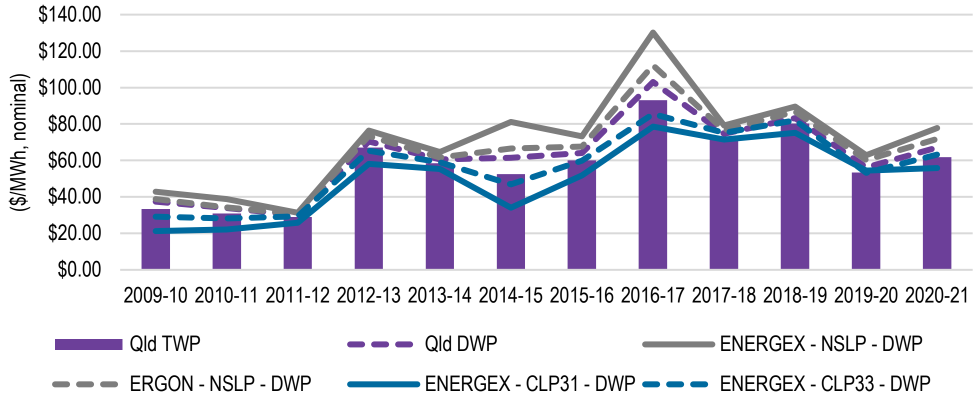
Source: ACIL Allen analysis of AEMO data

Figure 4.4 to Figure 4.6 show the actual annual DWP for each of the profiles compared with the regional TWP over the past 12 years. 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 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 four or so years has resulted in it having a DWP about equal to the DWP of the corresponding Endeavour NSLP.

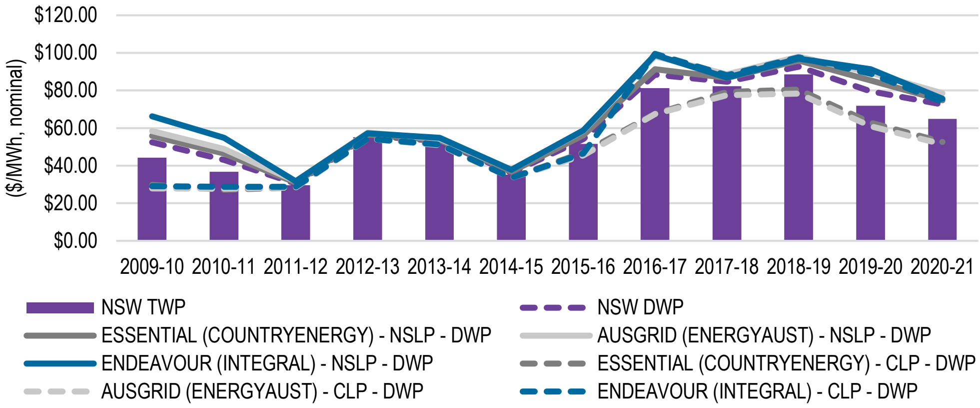
Over the past five to seven years, the increased uptake of rooftop PV has resulted in the DWPs of the NSLPs increasing above the corresponding regional TWP on consistent basis. The carve out of the NSLPs means that profiles are skewed towards the evening peaks when prices tend to be higher.

Figure 4.4 Actual annual average demand weighted price ($/MWh, nominal) by profile and Queensland time weighted average price ($/MWh, nominal) – 2009-10 to 2020-21



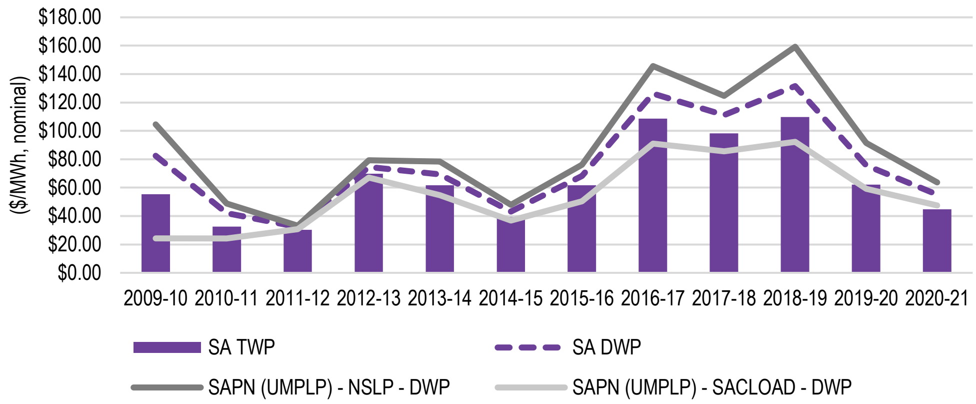
Note: Values reported are spot (or uncontracted) prices.
Source: ACIL Allen analysis of AEMO data

Figure 4.5 Actual annual average demand weighted price ($/MWh, nominal) by profile and New South Wales time weighted average price ($/MWh, nominal) – 2009-10 to 2020-21



Note: Values reported are spot (or uncontracted) prices.
Source: ACIL Allen analysis of AEMO data

Figure 4.6 Actual annual average demand weighted price ($/MWh, nominal) by profile and South Australia time weighted average price ($/MWh, nominal) – 2009-10 to 2020-21



Note: Values reported are spot (or uncontracted) prices.
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 4.7.

Compared with the 2021-22:

— Futures base contract prices for 2022-23, on an annualised and trade weighted basis to date, have:
  – increased by about $6.90/MWh for Queensland
  – increased by about $4.00/MWh for New South Wales
  – decreased by about $6.90/MWh for South Australia.
— Cap contract prices for 2022-23 have increased noticeably compared with 2021-22, and on an annualised and trade weighted basis to date, have:
  – increased by about $5.70/MWh for Queensland
  – increased by about $4.20/MWh for New South Wales
  – increased by about $3.80/MWh for South Australia.

Unlike the previous two DMOs in which there was a clear decline in contract prices, the market is now expecting an increase in price outcomes as the amount of utility scale renewable investment coming on-line slows between 2021-22 and 2022-23 (compared with recent years), coupled with the closure of Liddell in New South Wales, Torrens Island A in South Australia, the continued unavailability of Callide C Unit 4 for at least half of 2022-23, and stronger coal and gas prices.

Further, cap contract prices have increased substantially for 2022-23 compared with 2021-22. This may reflect a degree of uncertainty faced by providers of caps around the ability of their peaking plant to cover price spikes in the spot market under five-minute settlement (5MS), as well as an expectation of an increase in underlying price volatility. A $1/MWh increase in cap price can increase the WEC for a NSLP by about $3/MWh, all other things equal, due to the peaky shape of the NSLP.

This is further exacerbated by the expected continued strong uptake of rooftop PV which carves out the demand during daylight hours, 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.

The increase in contract prices means that the trade weighted average price levels to date for 2022-23 are quite similar to those of 2019-20. The decline in prices experienced since 2017-18 appears to have come to an end at this point in time.

Figure 4.7 Base, Peak, and Cap trade weighted average contract prices ($/MWh, nominal) – 2019-20 to 2022-23

Source: ACIL Allen analysis of ASX Energy Data

4.2 Estimation of the Wholesale Energy Cost

4.2.1 Estimating contract prices

Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed up until 11 January 2022 inclusive.

Table 4.1 to Table 4.3 show the estimated quarterly base and peak swap, and cap contract prices for 2021-22 and 2022-23. Base contract prices generally increase from 2021-22 to 2022-23 for Queensland and New South Wales; whereas they generally decrease slightly in South Australia. However, there are strong increases in cap prices across all regions. Peak prices have also increased strongly across all regions.

This combination of slightly increasing or decreasing base prices, strong increasing peak and cap prices suggests the market is expecting a further decline in spot prices across daylight hours which is offset by increase in spot prices during evening and possibly morning peak. This will increase the cost of hedging the NSLPs.

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

	Q3	Q4	Q1	Q2
2021-22				
Base	$42.20	$43.98	$61.09	$41.22
Peak	$55.38	$55.21	$76.75	$45.00
Cap	$1.99	$4.76	$12.45	$3.25
2022-23				
Base	$51.42	$53.52	$65.65	$45.65
Peak	$62.00	$65.40	$117.33	$72.88
Cap	$5.81	$9.15	$24.42	$5.86
Percentage change from 2021-22 to 2022-23				
Base	22%	22%	7%	11%
Peak	12%	18%	53%	62%
Cap	192%	92%	96%	80%

Source: ACIL Allen analysis using ASX Energy and TFS data up to 11 January 2022 for 2022-23

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

	Q3	Q4	Q1	Q2
2021-22				
Base	$54.03	$54.39	$72.52	$51.40
Peak	$65.62	$64.72	$85.55	$57.00
Cap	$3.50	$7.34	$19.12	$3.50
2022-23				
Base	$60.62	$57.59	$71.53	$58.54
Peak	$75.85	$72.25	$113.02	$98.21
Cap	$7.78	$10.14	$24.66	$7.71
Percentage change from 2021-22 to 2022-23				
Base	12%	6%	-1%	14%
Peak	16%	12%	32%	72%
Cap	122%	38%	29%	120%

Source: ACIL Allen analysis using ASX Energy and TFS data up to 11 January 2022 for 2022-23

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

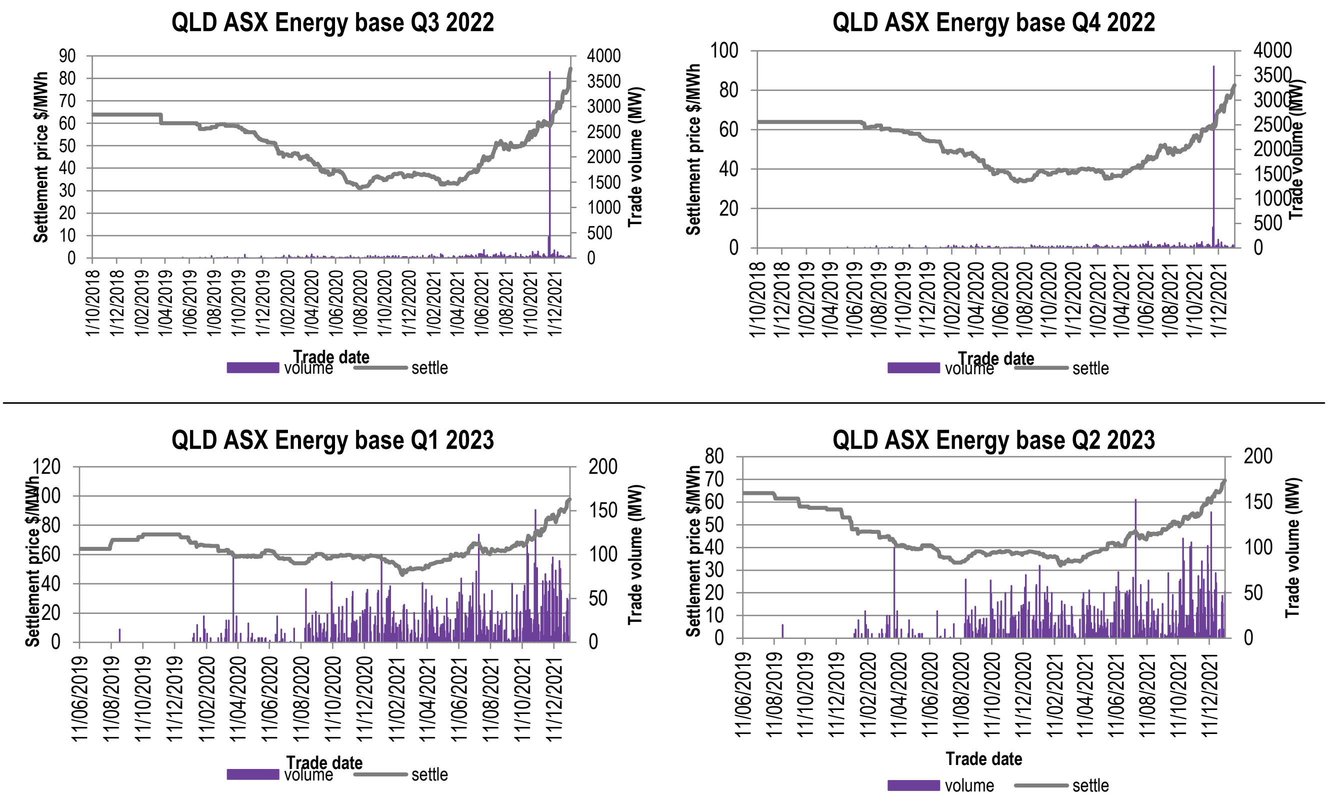
	Q3	Q4	Q1	Q2
		2021-22		
Base	$54.73	$53.59	$71.75	$41.28
Peak	$56.00	$59.00	$78.12	$42.65
Cap	$2.71	$6.75	$20.99	$2.74
		2022-23		
Base	$44.77	$39.95	$62.90	$46.21
Peak	$69.90	$67.12	$106.66	$61.00
Cap	$4.44	$8.62	$30.49	$5.05
		Percentage change from 2021-22 to 2022-23		
Base	-18%	-25%	-12%	12%
Peak	25%	14%	37%	43%
Cap	64%	28%	45%	84%

Source: ACIL Allen analysis using ASX Energy and TFS data up to 11 January 2022 for 2022-23

In addition to the increase in rooftop PV, another driver of change in the relativity of base and cap contract prices in 2022-23 is an increase in gas prices for gas fired generation. Spot prices across the east coast gas market have increased from their lower levels observed over the previous few years to about $10/GJ - a reflection of higher international LNG prices which affects domestic gas prices via a higher LNG netback price.

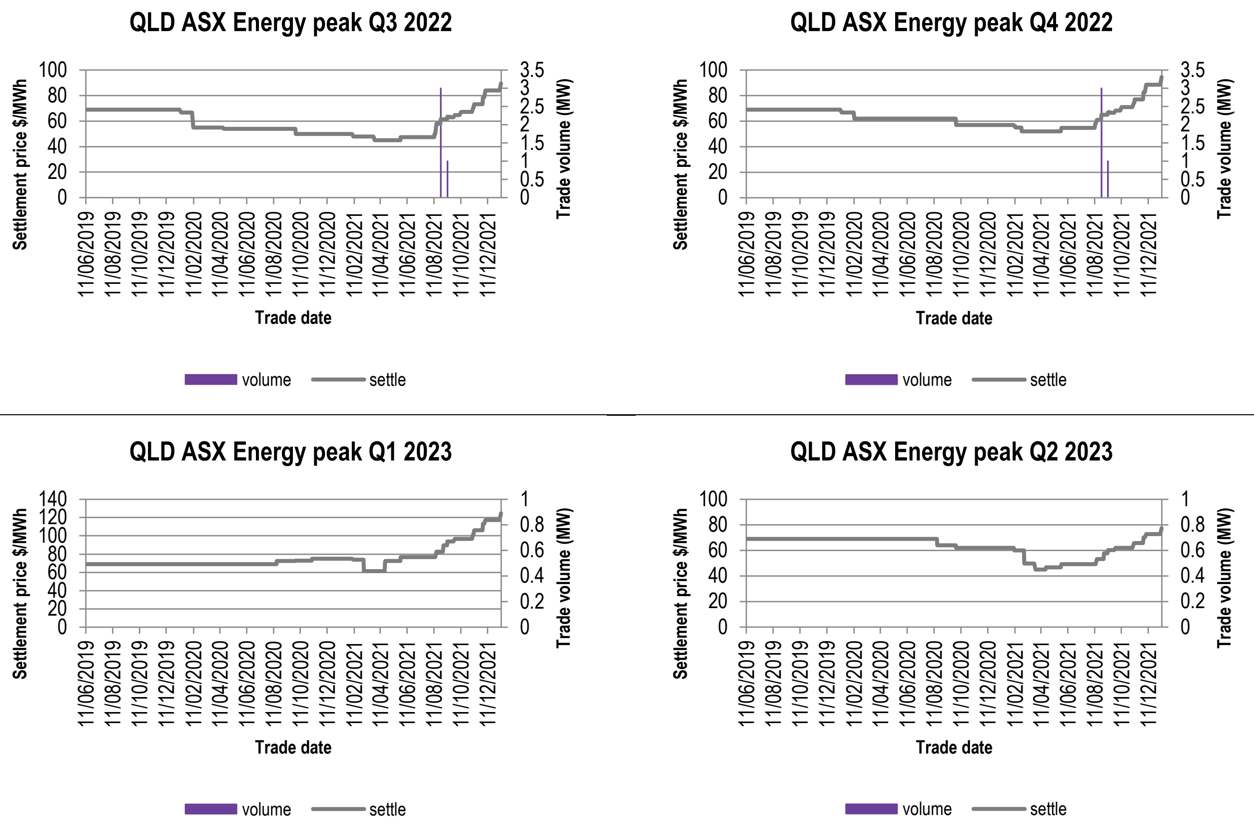
The following charts show daily settlement prices and trade volumes for 2022-23 ASX Energy quarterly base futures, peak futures and cap contracts up to 11 January 2022. It can be seen that the trading of these contracts tends to commence from mid to late 2019.

Figure 4.8 Time series of trade volume and price – ASX Energy base futures - Queensland



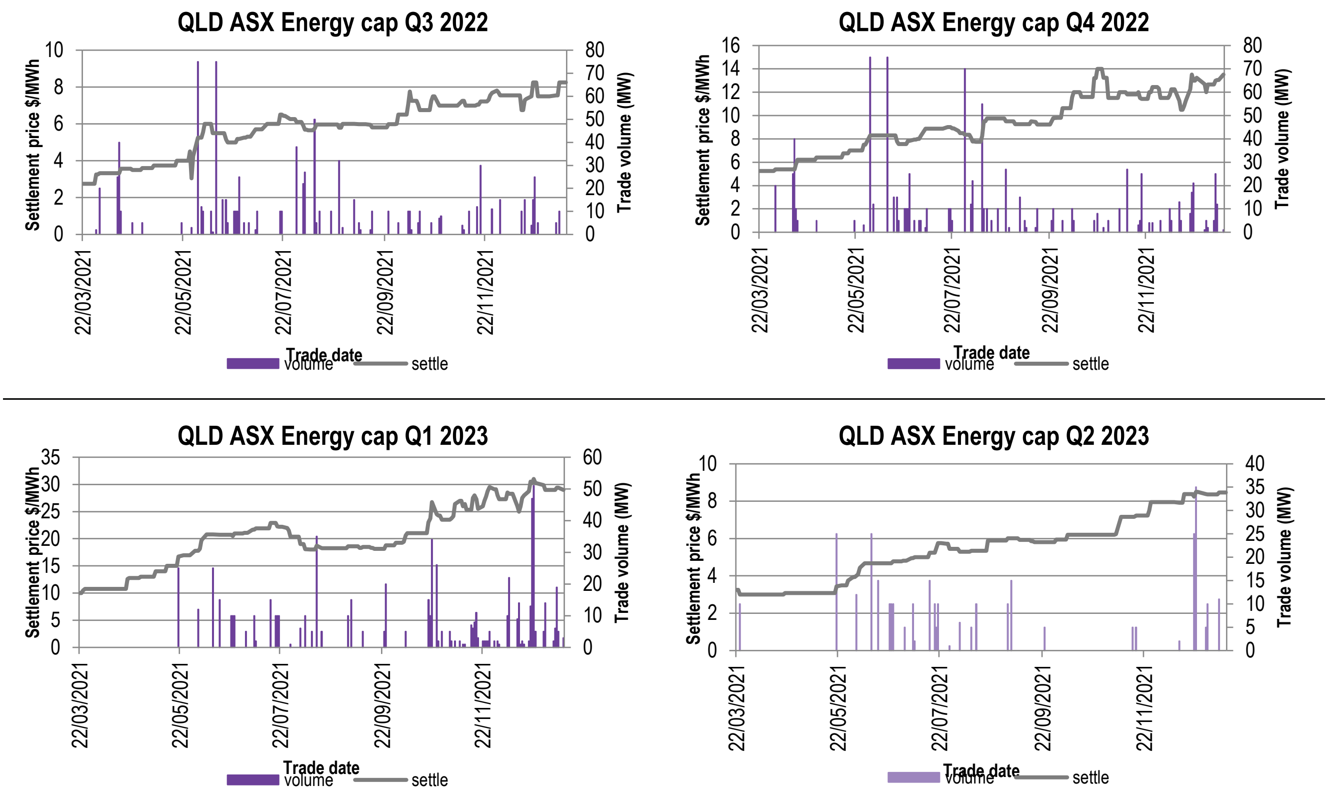
Source: ASX Energy data up to 11 January 2022

Figure 4.9 Time series of trade volume and price – ASX Energy peak futures - Queensland



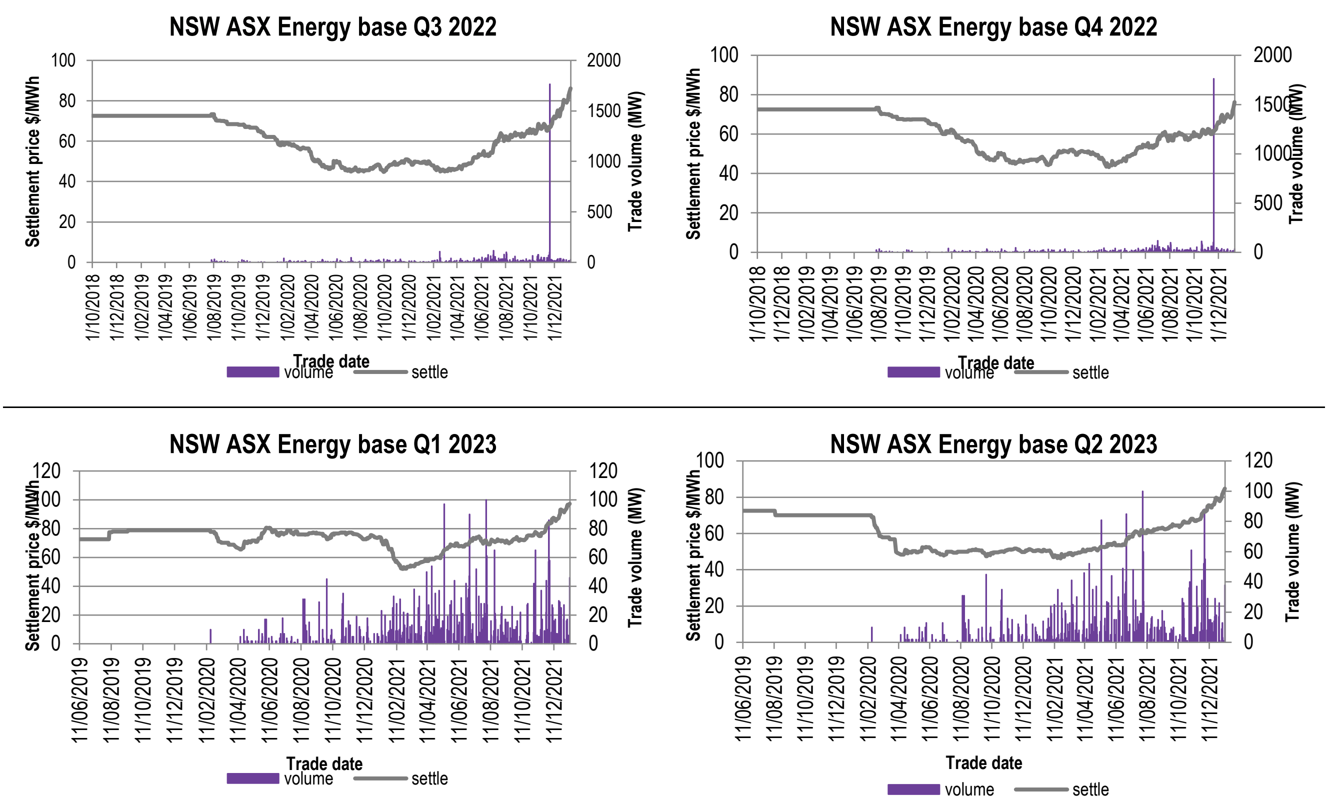
Source: ASX Energy data up to 11 January 2022

Figure 4.10 Time series of trade volume and price – ASX Energy $300 cap futures - Queensland



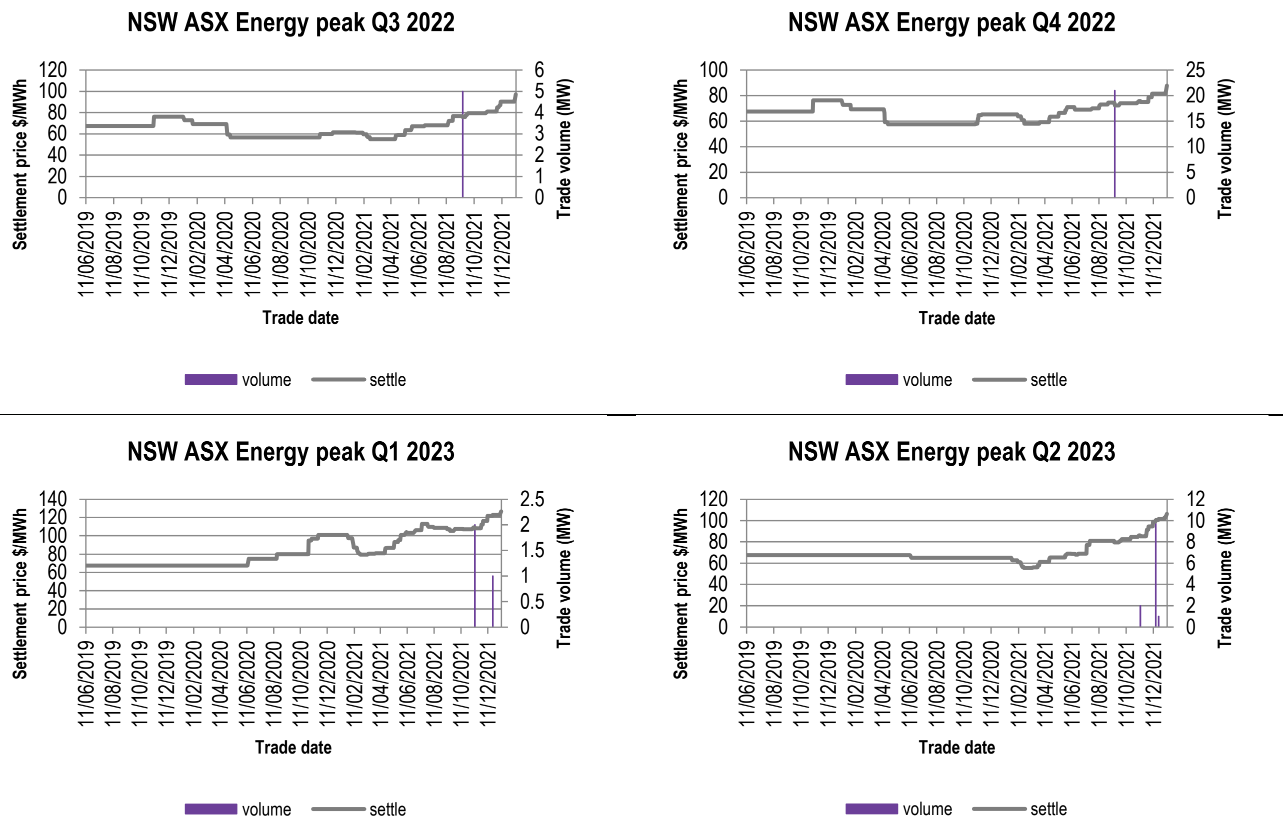
Source: ASX Energy data up to 11 January 2022

Figure 4.11 Time series of trade volume and price – ASX Energy base futures – New South Wales



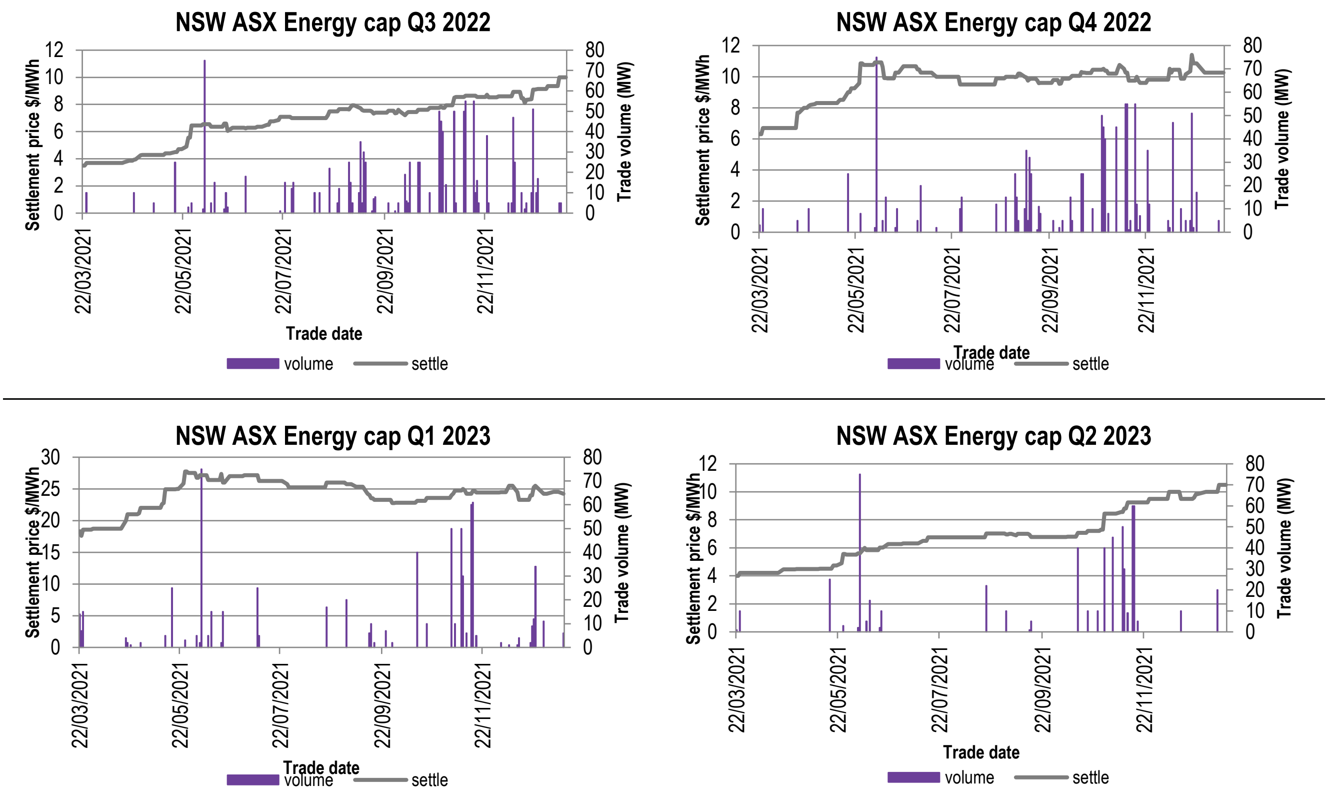
Source: ASX Energy data up to 11 January 2022

Figure 4.12 Time series of trade volume and price – ASX Energy peak futures – New South Wales



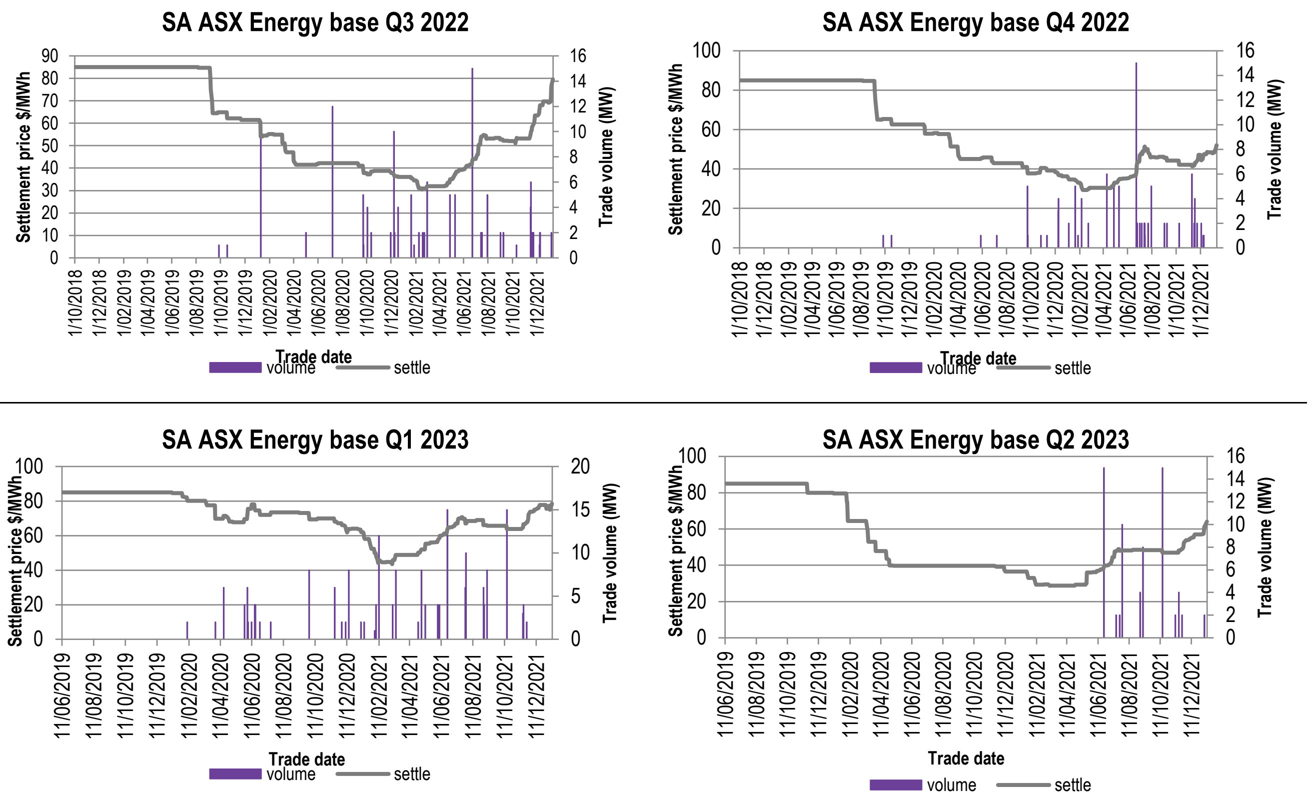
Source: ASX Energy data up to 11 January 2022

Figure 4.13 Time series of trade volume and price – ASX Energy $300 cap futures – New South Wales



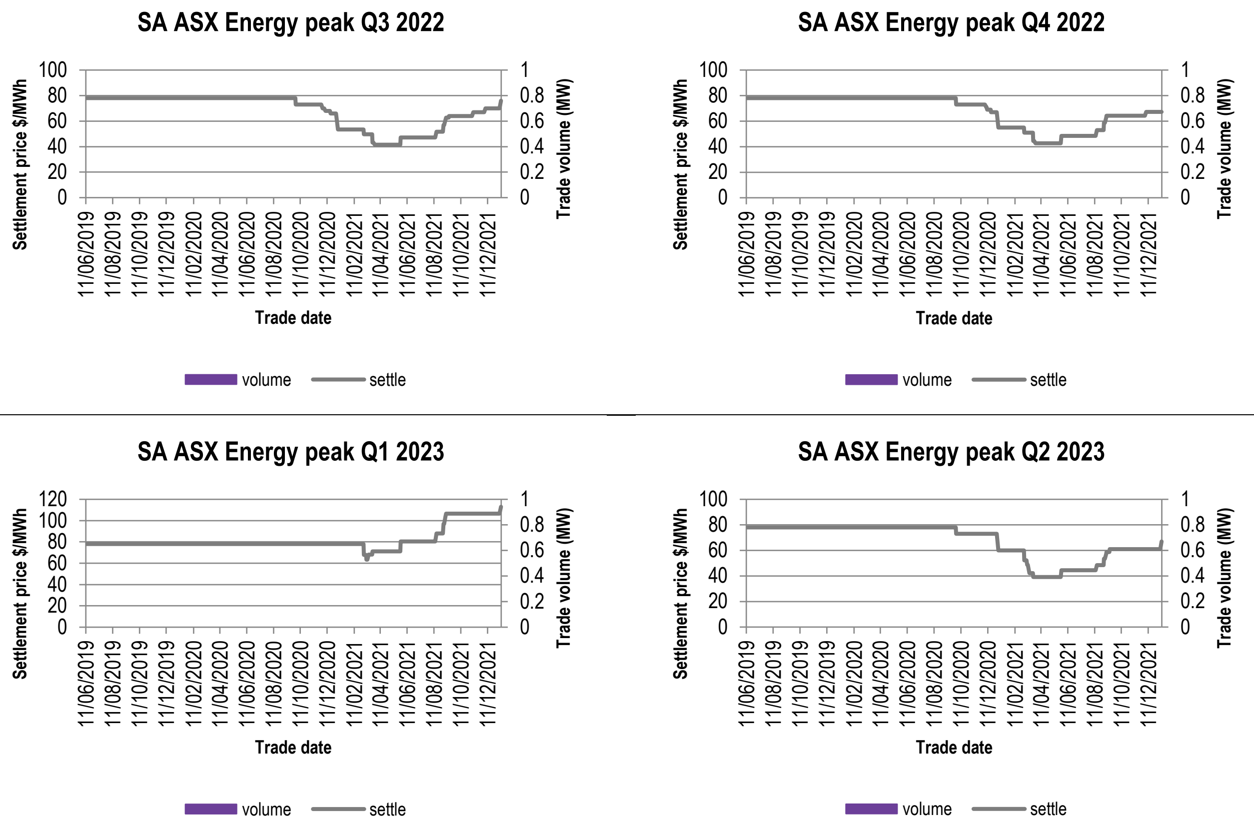
Source: ASX Energy data up to 11 January 2022

Figure 4.14 Time series of trade volume and price – ASX Energy base futures – South Australia



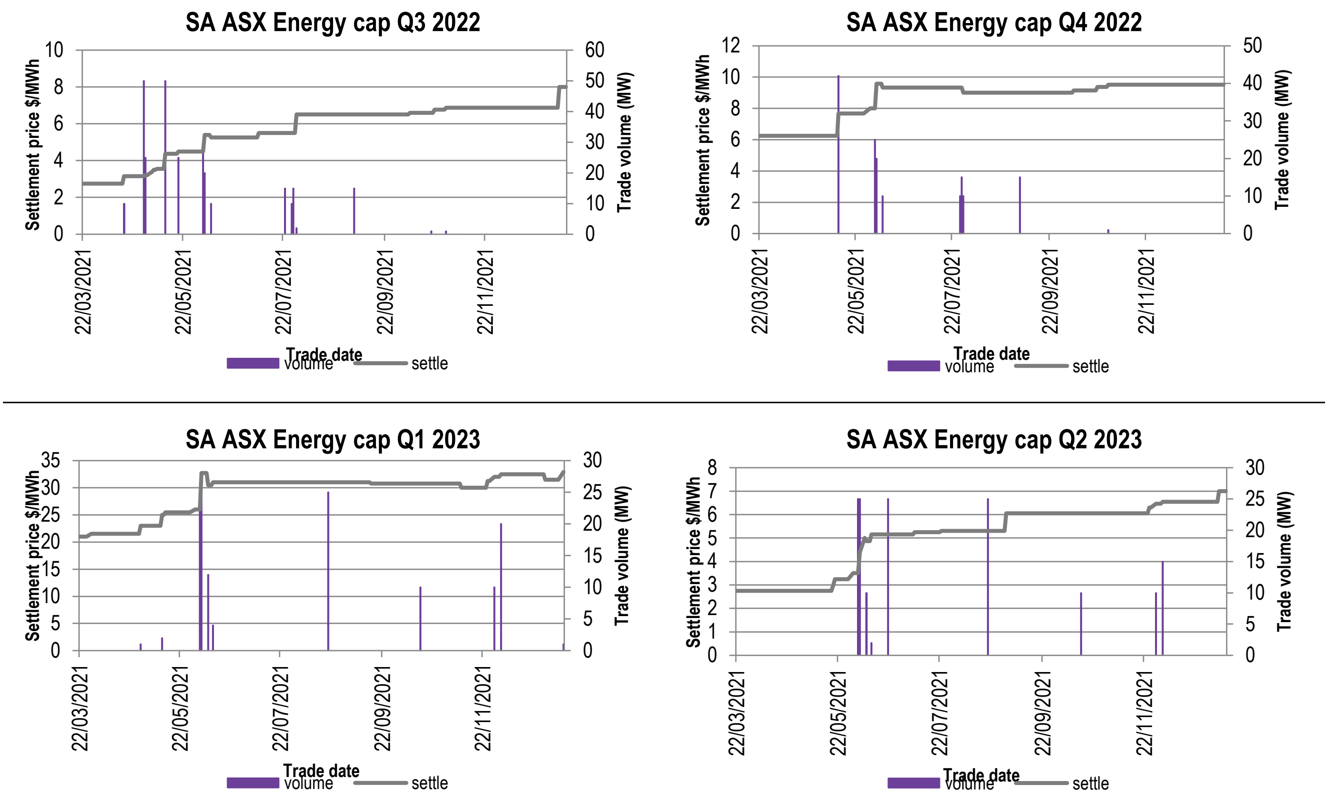
Source: ASX Energy data up to 11 January 2022

Figure 4.15 Time series of trade volume and price – ASX Energy peak futures – South Australia



Source: ASX Energy data up to 11 January 2022

Figure 4.16 Time series of trade volume and price – ASX Energy $300 cap futures – South Australia



Source: ASX Energy data up to 11 January 2022

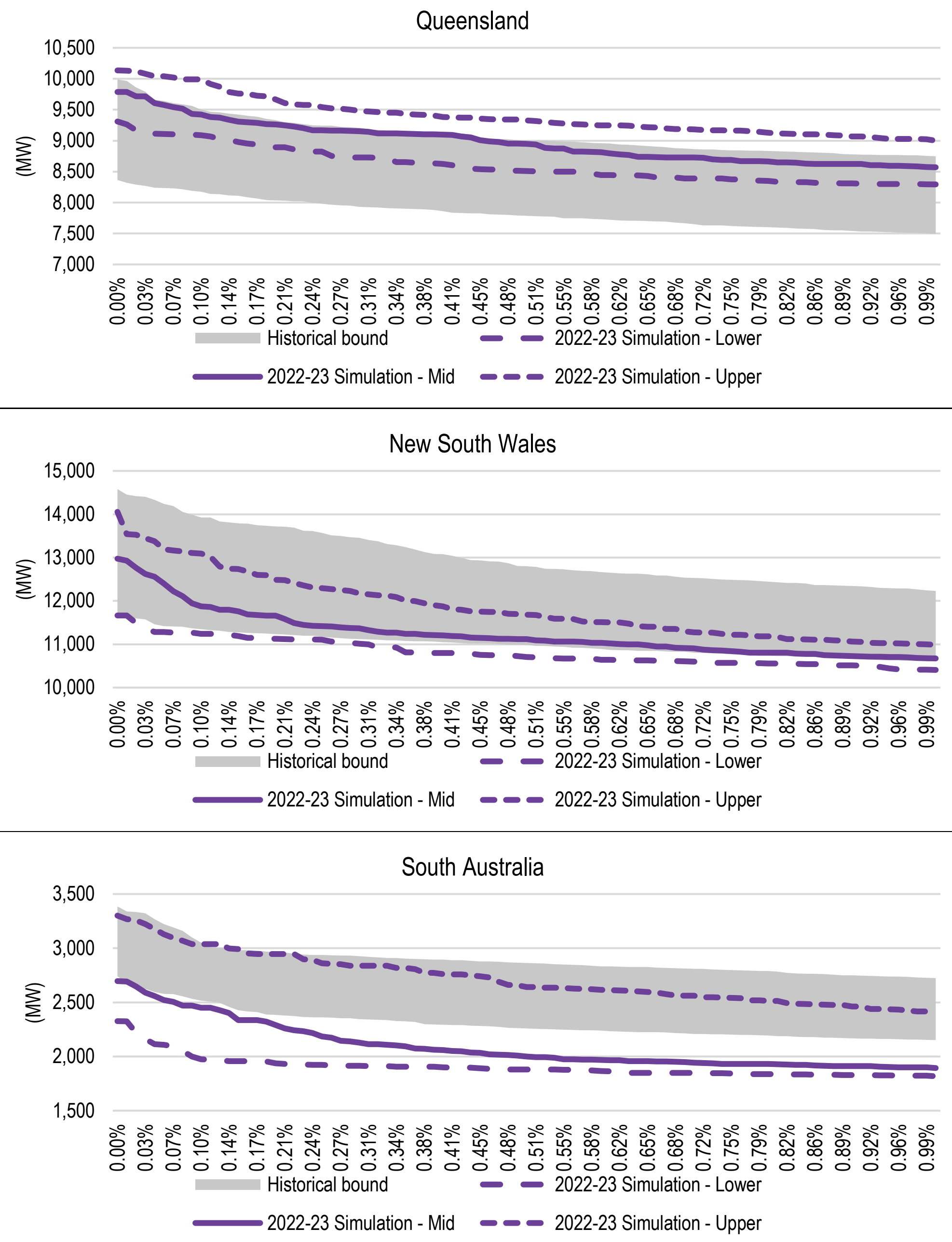
4.2.2 Estimating wholesale spot prices

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 4.17 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 2022-23, 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 2022-23 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 2022-23 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 2022-23 in South Australia are slightly lower than historic levels due to reductions in industrial load. 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 4.17 Comparison of upper one per cent of hourly regional system loads of 2022-23 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 4.18 shows the range of the simulated NSLP demands envelope recent actual outcomes. This variation results in the annual load factor[9] of the 2022-23 simulated demand sets ranging between:

— 28 percent and 36 percent compared with a range of 29 percent to 43 percent for the actual Energex NSLP between 2009-10 and 2020-21 (as shown in Figure 4.19)

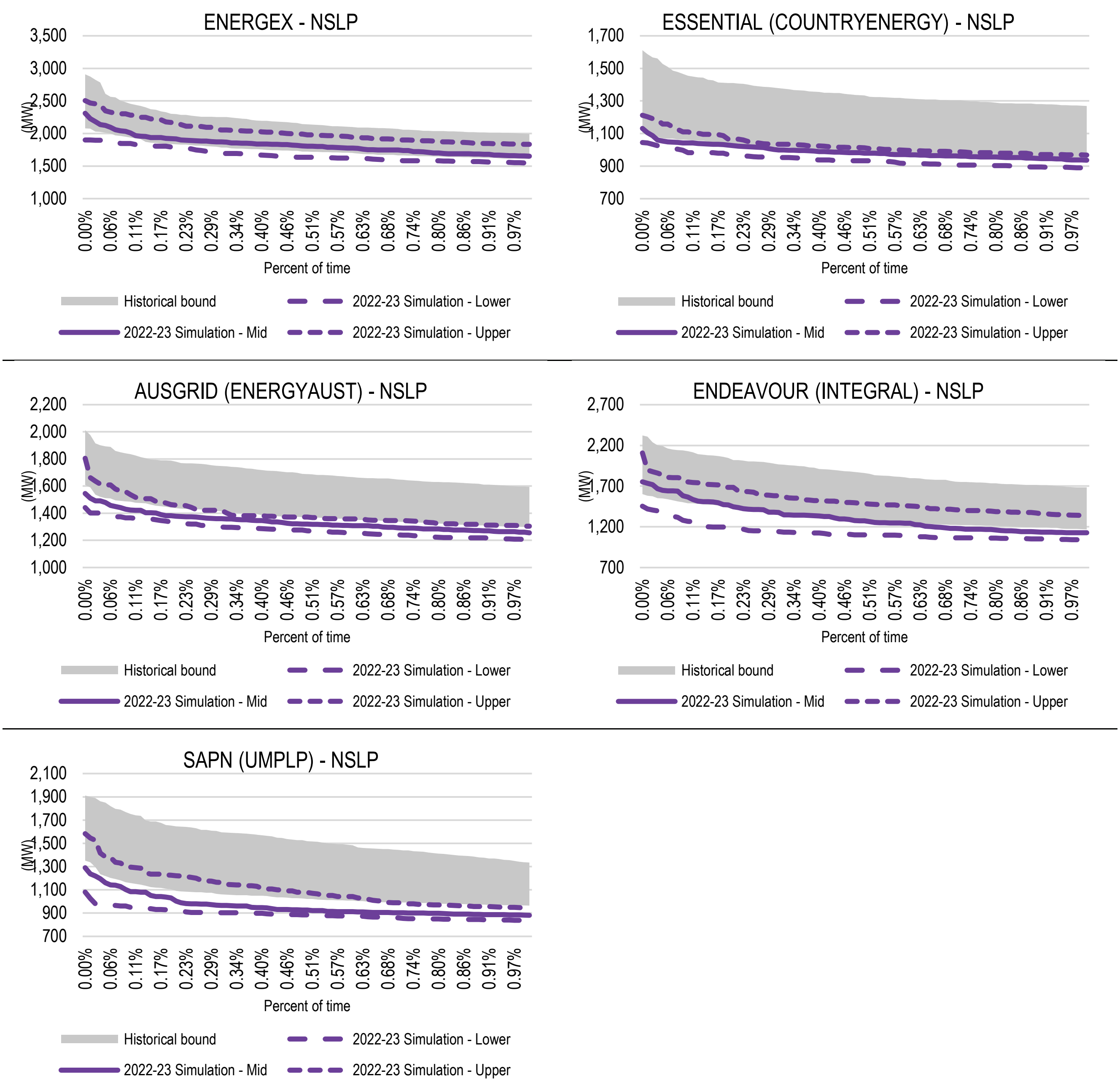
[9] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

- 38 percent and 44 percent compared with a range of 41 percent to 51 percent for the actual Essential NSLP between 2009-10 and 2020-21
- 28 percent and 35 percent compared with a range of 31 percent to 36 percent for the actual Ausgrid NSLP between 2009-10 and 2020-21
- 24 percent and 35 percent compared with a range of 31 percent to 39 percent for the actual Endeavour NSLP between 2009-10 and 2020-21
- 17 percent and 26 percent compared with a range of 21 percent to 33 percent 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 over the past eight or so years 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.

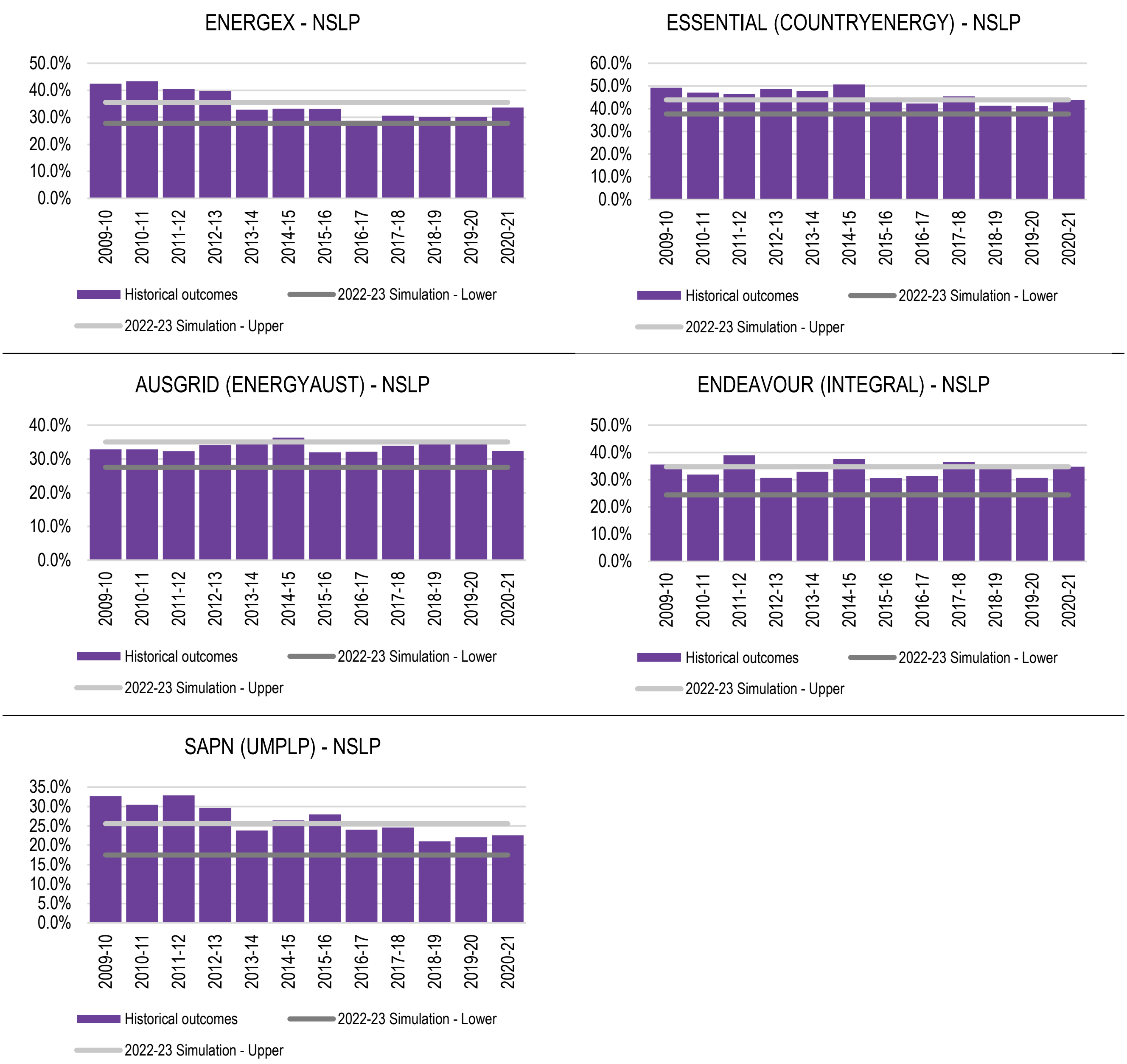
All other things being equal, the increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging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

Figure 4.18 Comparison of upper one per cent of hourly NSLPs of 2022-23 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 4.19 Comparison of load factor of 2022-23 simulated hourly demand sets with historical outcomes - NSLPs

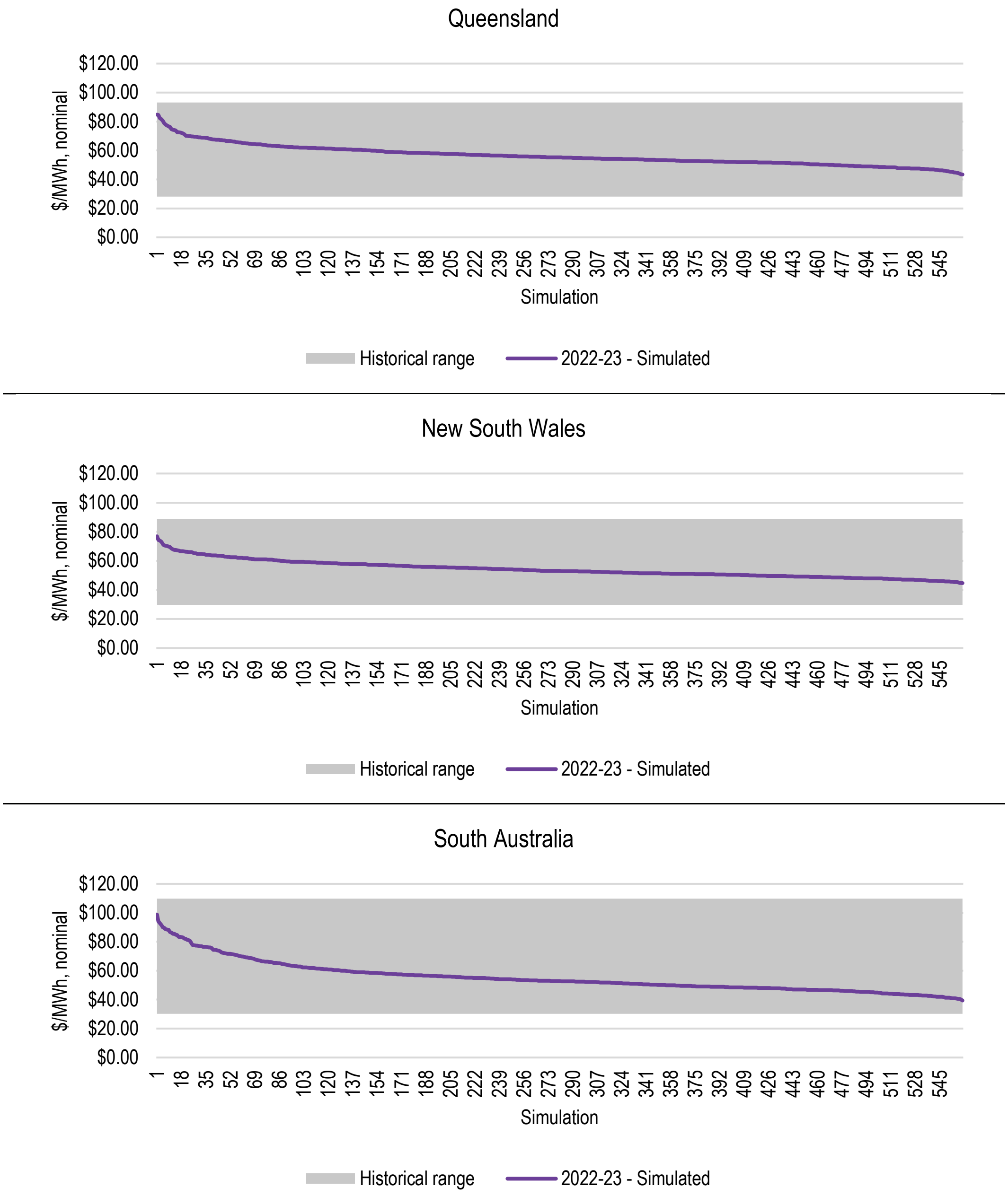


Source: ACIL Allen analysis and AEMO data

Figure 4.20 compares the modelled annual regional TWP for the 561 simulations for 2022-23 with the regional TWPs from the past 21 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 price outcomes for 2022-23 when compared with the past 21 years of history.

ACIL Allen is satisfied that in an aggregate sense the distribution of the 561 simulations for 2022-23 cover an adequately wide range of possible annual pool price outcomes for all three regions.

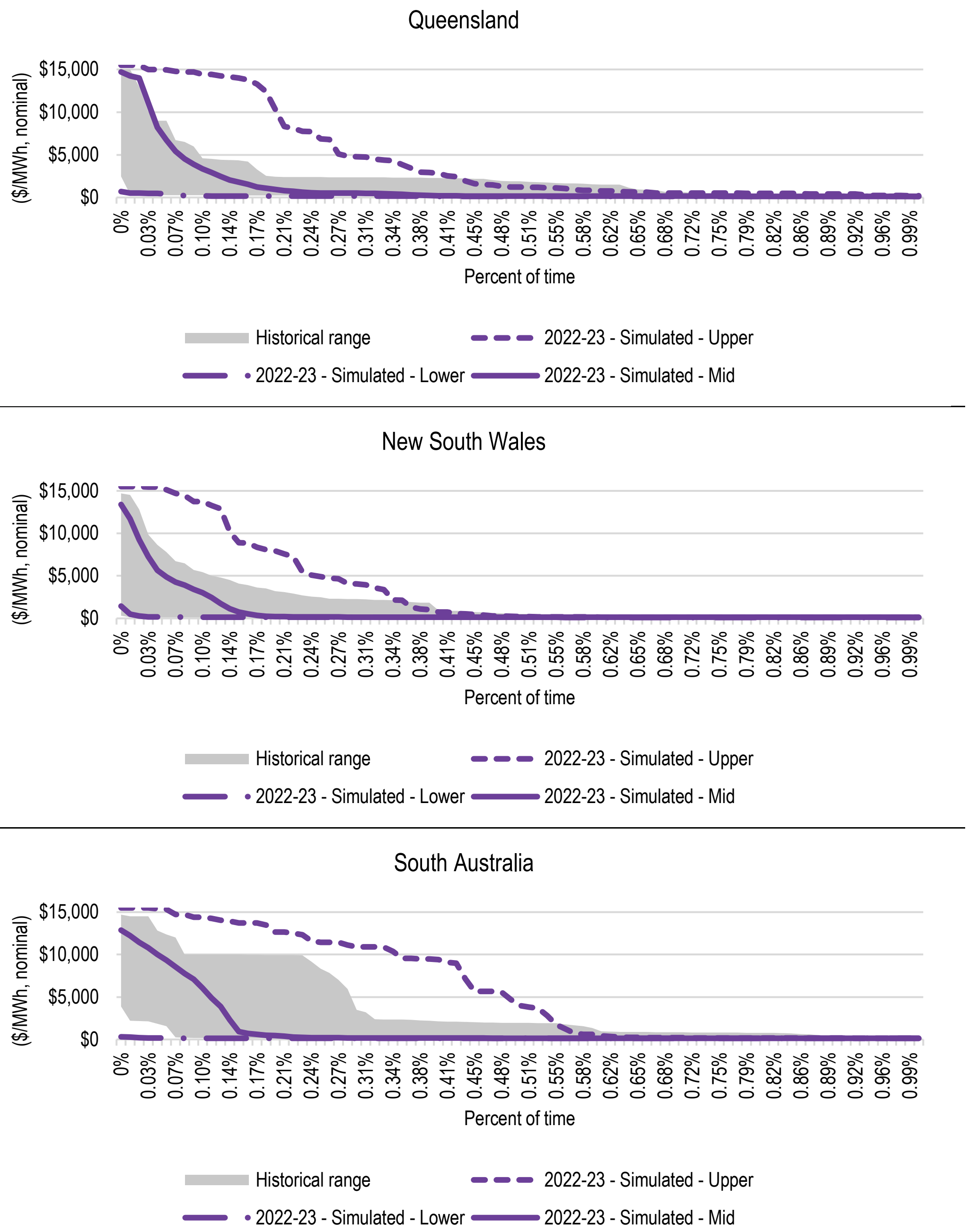
Figure 4.20 Simulated annual TWP for Queensland, New South Wales, and South Australia for 2022-23 compared with range of actual annual outcomes in past years



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 Figure 4.21. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

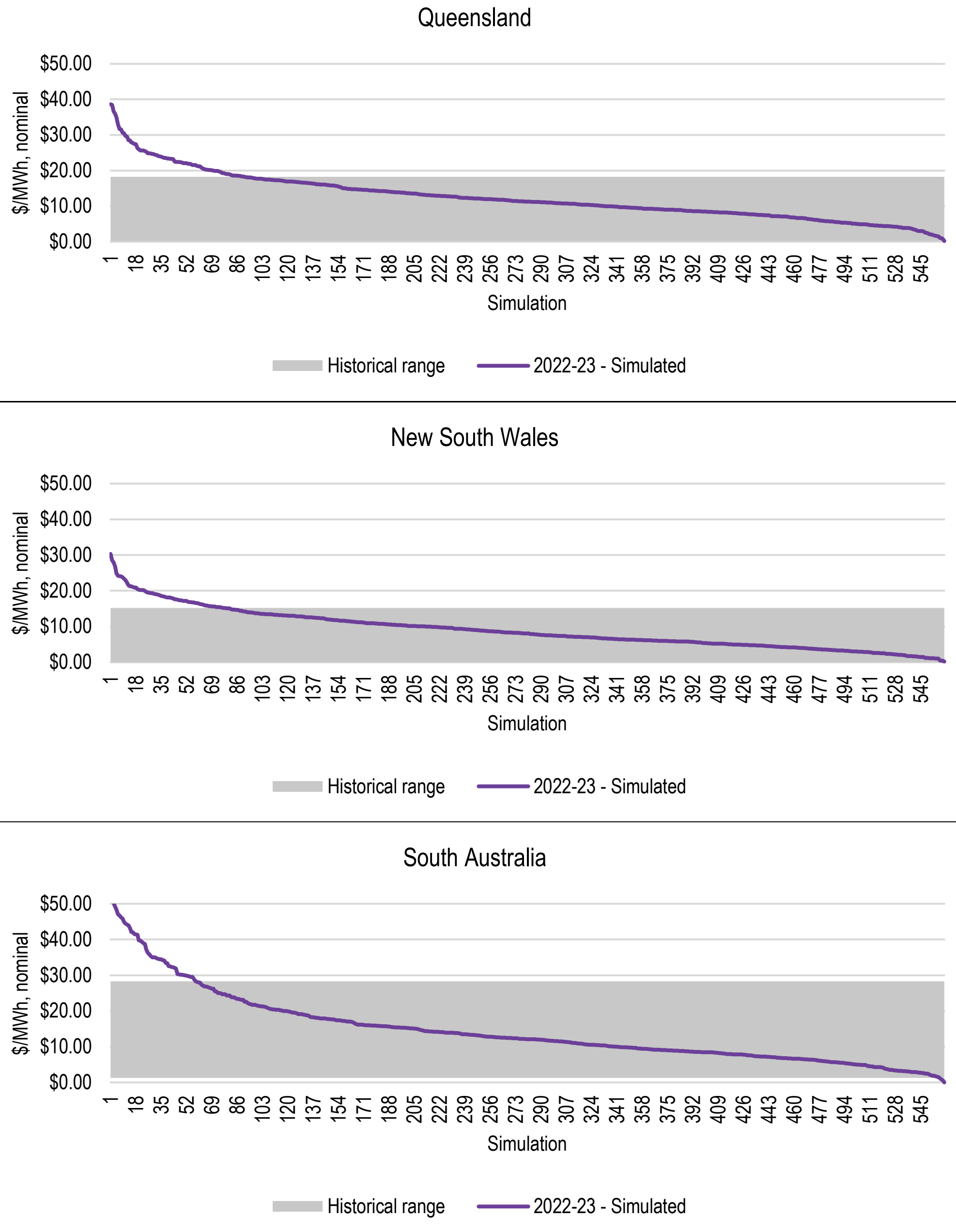
Figure 4.21 Comparison of upper 1 percent tail of simulated hourly price duration curves for Queensland, New South Wales, and South Australia for 2022-23 and range of actual outcomes in past years



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 4.22. For some of the 2022-23 simulations the contribution of price spikes is greater than historical levels, reflecting the greater variability in thermal power station availability (such as the continued outage of Callide C Unit 4), and the general tightening of the demand-supply balance in the market.

Figure 4.22 Annual average contribution to the Queensland, New South Wales, and South Australia TWP by prices above $300/MWh in 2022-23 for simulations compared with range of actual outcomes in past years



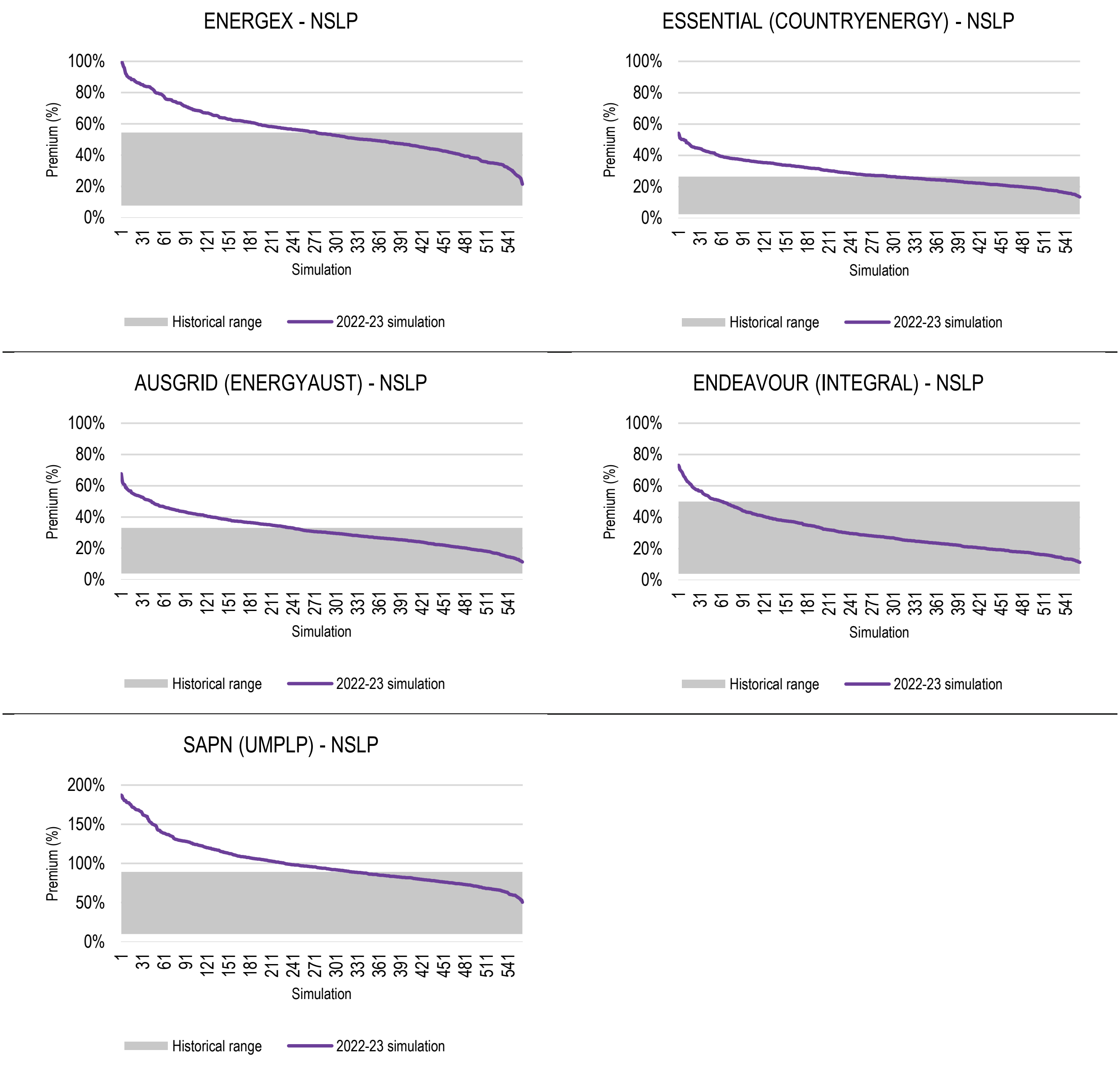
Source: ACIL Allen analysis and AEMO data

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 4.23 shows that, for the past 11 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 2022-23 for each NSLP, this percentage varies from 11 percent to 172 percent. The modelling suggests a greater range in the premium for 2022-23 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 when the NSLP demand is at its lowest.

The comparison with actual outcomes over the past 11 years in Figure 4.23 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 561 simulations is sound.

Figure 4.23 Simulated annual DWP for NSLP as a percentage premium of annual TWP for 2022-23 compared with range of actual outcomes in past years



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 2022-23 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 2022-23.

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 2022-23 are calculated for each NSLP for each quarter as follows, and are largely unchanged from DMO 3:

— The base contract volume is set to equal the 50th (Endeavour, Essential, SAPN), 60th (Energex, Ausgrid,) percentile of the off-peak period hourly demands across all 51 demand sets for the quarter.

— The peak period contract volume is set to equal the 50th (Ausgrid, Essential, Endeavour, SAPN), 60th (Energex) percentile of the peak period hourly demands across all 51 demand sets minus the base contract volumes for the quarter.

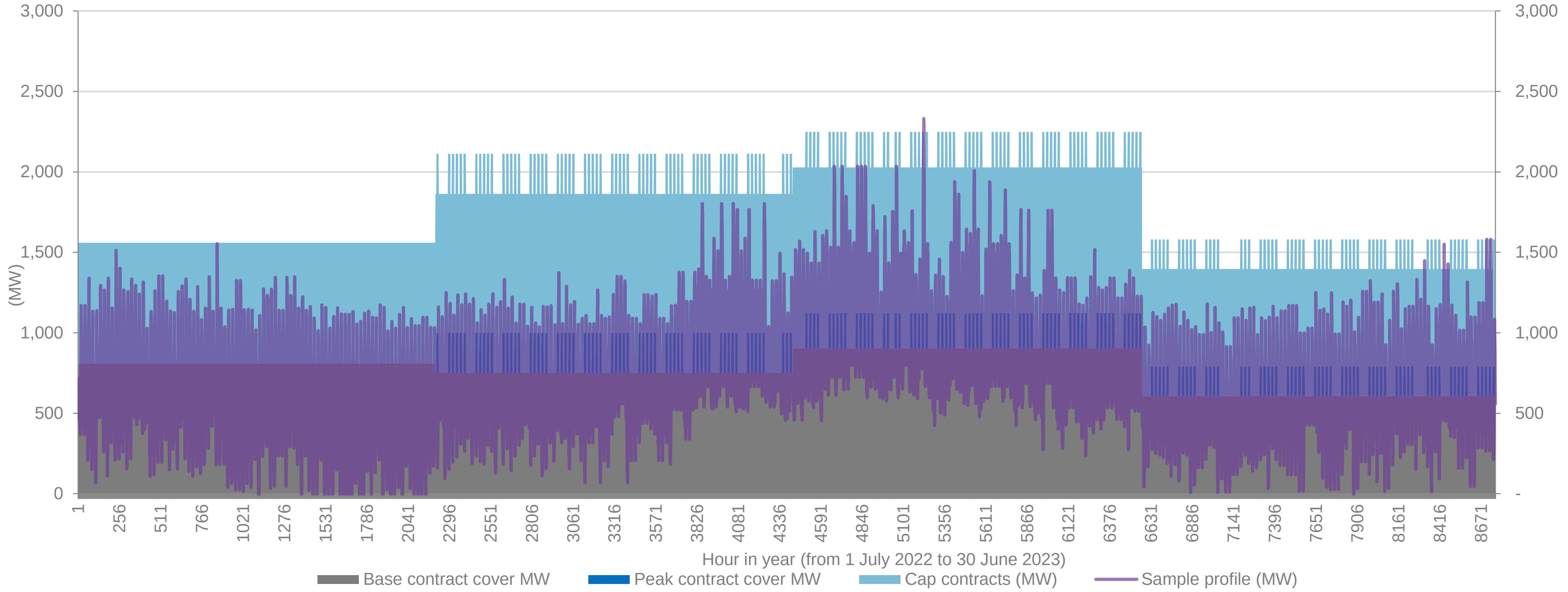
— The cap contract volume is set at 90 (SAPN), 100 (Energex, Essential, Endeavour), 110 (Ausgrid) per cent of the median of the annual peak demands across the 51 demand sets minus the base and peak contract volumes.

In other words, the 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 4.24 to Figure 4.28.

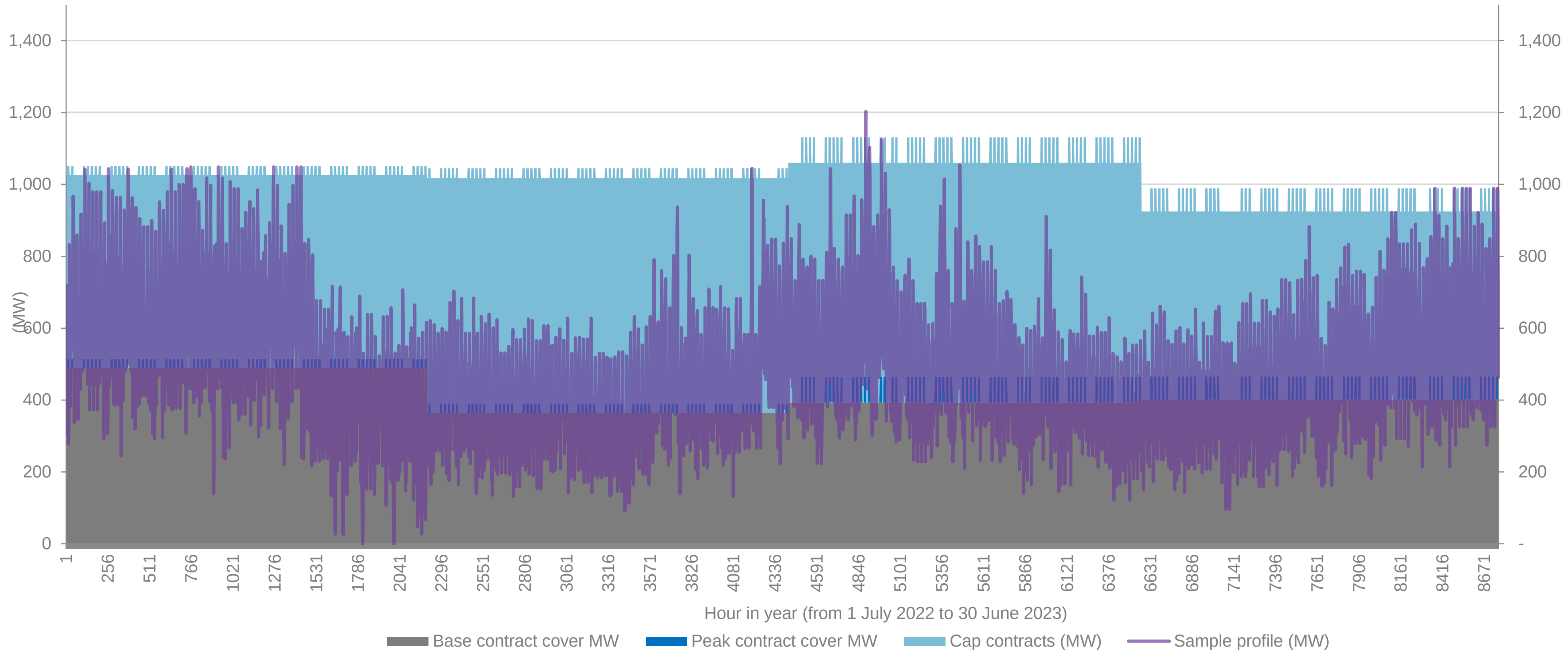
Generally, the contracting strategies place little reliance on peak contracts. This is not surprising – the carve out of demand during daylight hours (which makes up a reasonable part of the peak hours on business days), and the corresponding low spot prices during those hours makes the peak contacts 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 strategies' very low reliance on peak contracts matches well with the very small volume of peak contracts traded relative to base contracts in the actual futures market.

Figure 4.24 Contract volumes used in hedge modelling of 561 simulations for 2022-23 for Energex NSLP



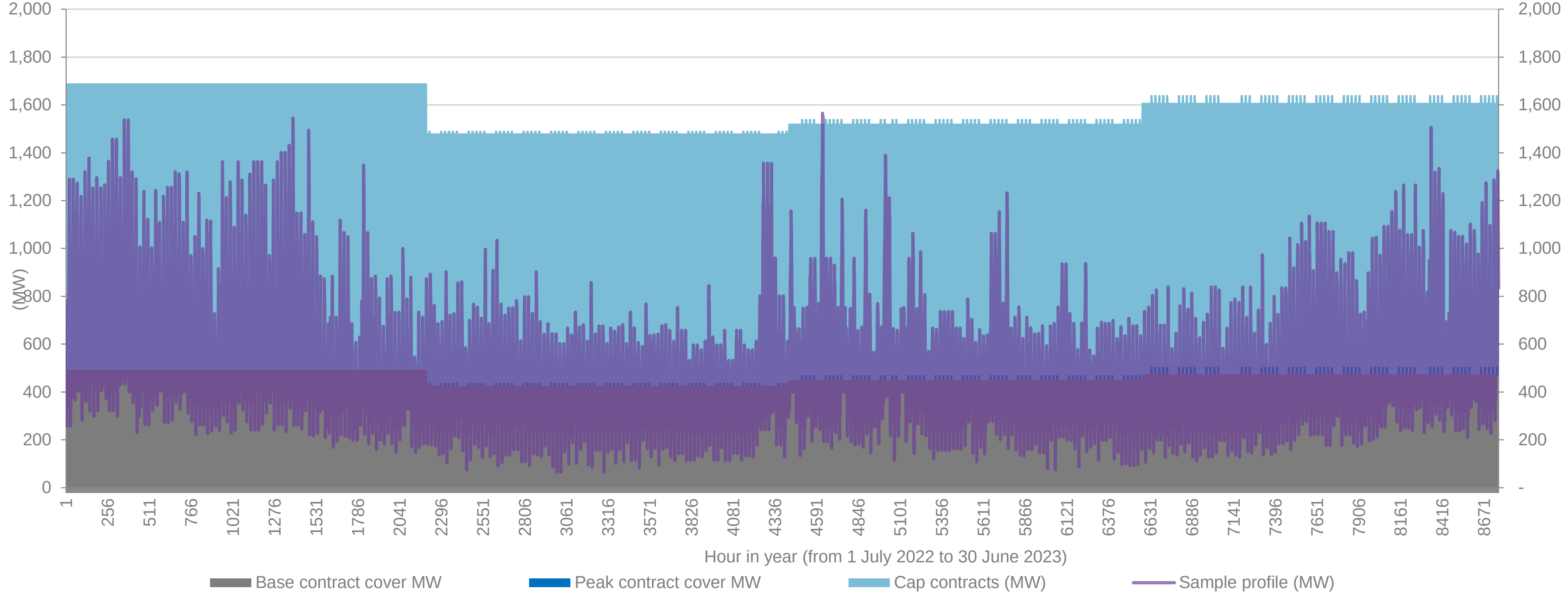
Source: ACIL Allen analysis

Figure 4.25 Contract volumes used in hedge modelling of 561 simulations for 2022-23 for Essential (COUNTRYENERGY)



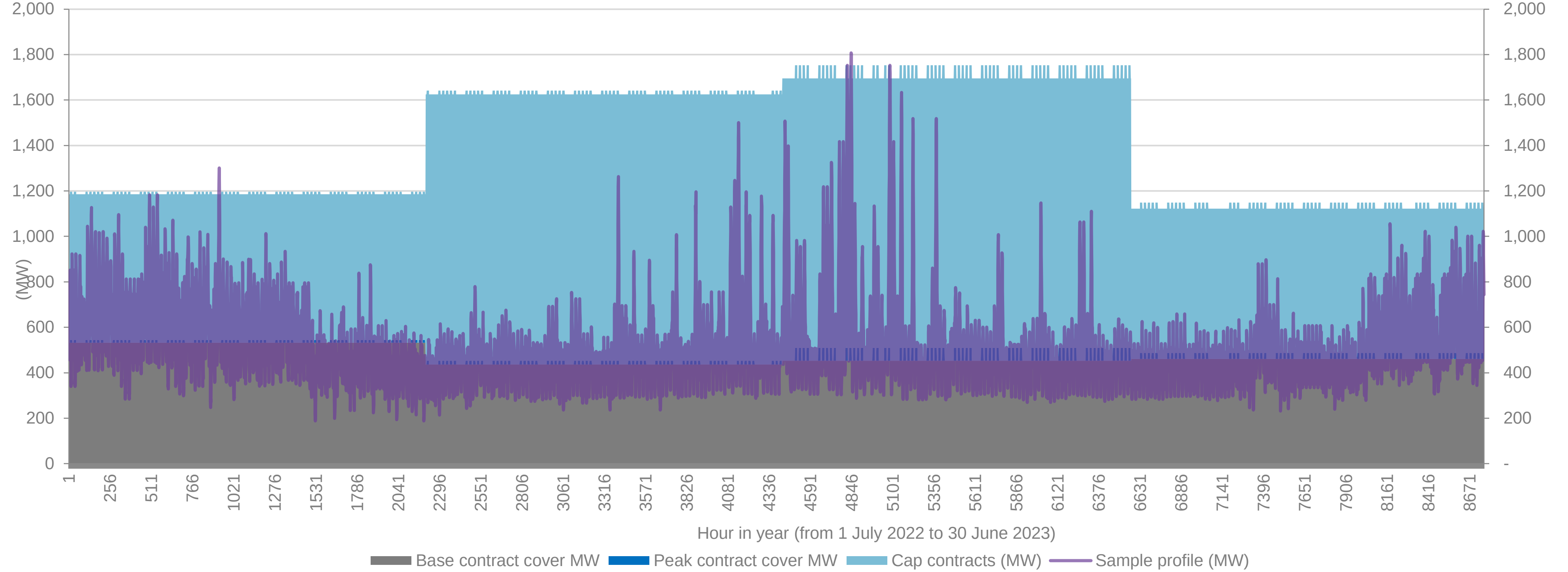
Source: ACIL Allen analysis

Figure 4.26 Contract volumes used in hedge modelling of 561 simulations for 2022-23 for Ausgrid (ENERGYAUST)



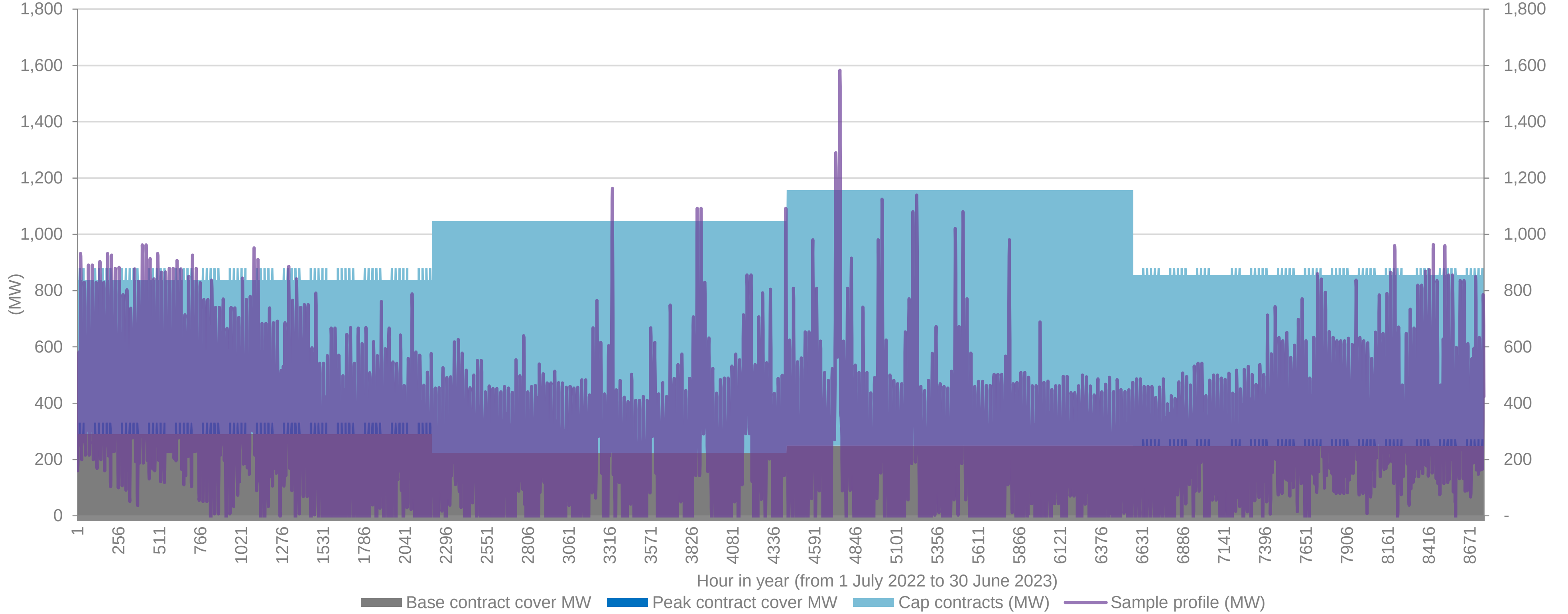
Source: ACIL Allen analysis

Figure 4.27 Contract volumes used in hedge modelling of 561 simulations for 2022-23 for Endeavour (INTEGRAL)



Source: ACIL Allen analysis

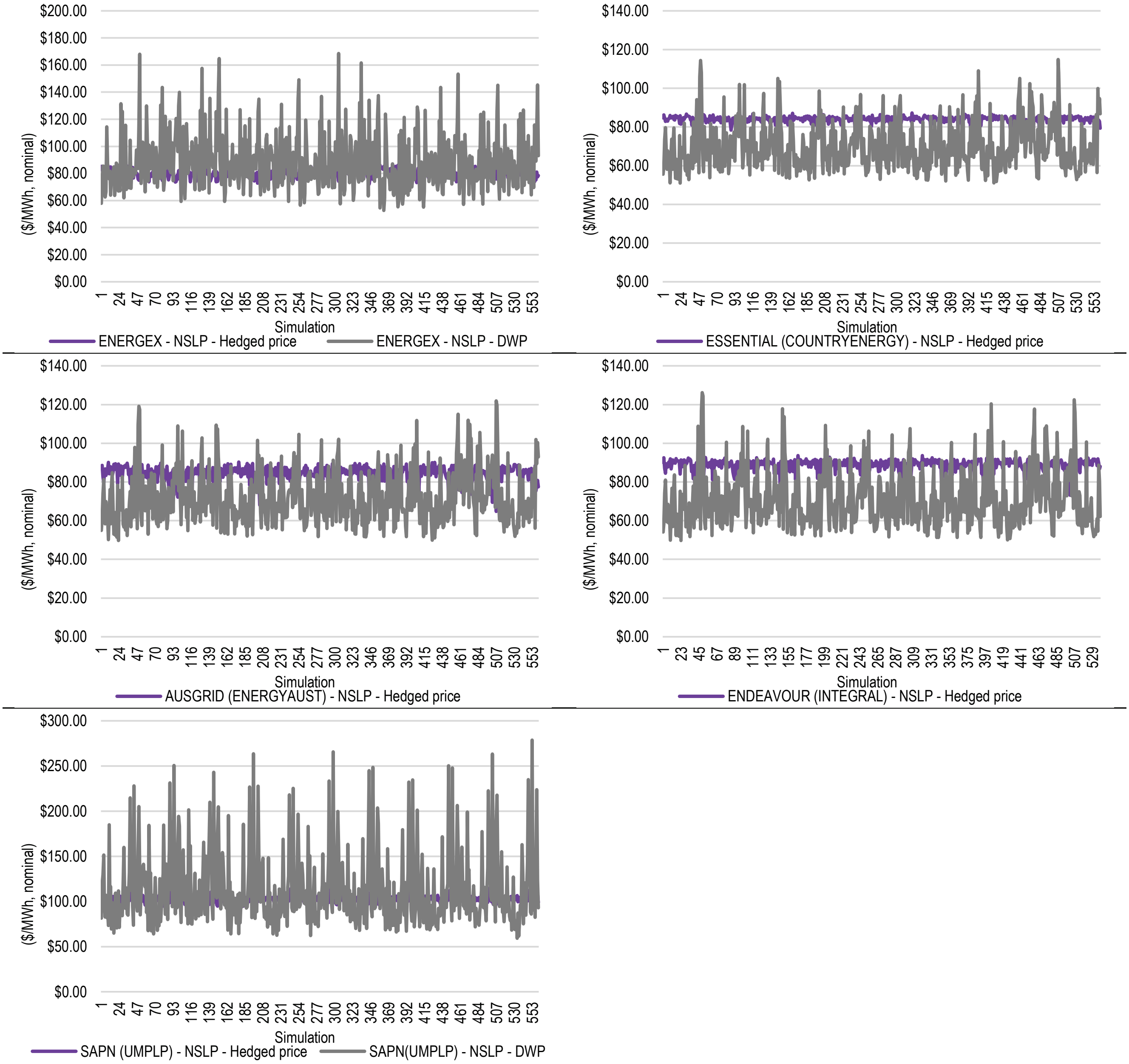
Figure 4.28 Contract volumes used in hedge modelling of 561 simulations for 2022-23 for SAPN (UMPLP)



Source: ACIL Allen analysis

Figure 4.29 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.

Figure 4.29 Annual hedged price and DWP ($/MWh, nominal) for NSLPs for the 561 simulations – 2022-23



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 2022-23 are shown in Table 4.4.

Table 4.4 Estimated WEC ($/MWh, nominal) for 2022-23 at the regional reference node

Settlement class	2021-22 – Final Determination	2022-23 – Draft Determination	Change from 2021-22 to 2022-23 (%)
Ausgrid - NSLP	$80.88	$90.04	11.33%
Endeavour - NSLP	$80.69	$90.45	12.10%
Essential - NSLP	$74.52	$84.90	13.93%
Ausgrid - CLP1	$54.58	$57.64	5.61%
Ausgrid - CLP2	$51.76	$57.28	10.66%
Endeavour - CLP	$76.00	$83.06	9.29%
Essential - CLP	$62.04	$62.03	-0.02%
Energex - NSLP	$67.01	$83.03	23.91%
Energex - CLP1	$52.73	$64.48	22.28%
Energex - CLP2	$54.93	$61.92	12.73%
SAPN - NSLP	$101.75	$104.35	2.56%
SAPN - CLP	$60.02	$50.26	-16.26%

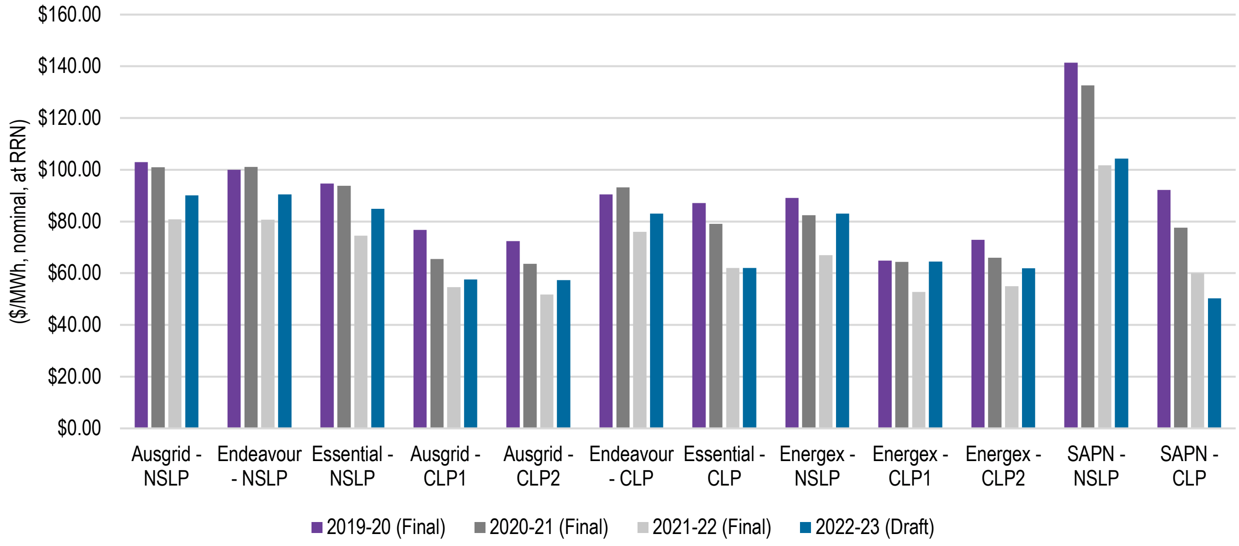
Source: ACIL Allen analysis

The 2022-23 WECs for the NSLPs and CLPs increase by between three and 24 per cent compared with 2021-22 – reflecting the strong increase on cap contract prices and decline in spot prices during daylight hours when demand is at its lowest point and hence over contracted. The exception are the CLPs in the Essential network and South Australia which decrease given their profiles are weighted towards hours when spot prices are projected to decrease. The WECs in south-east Queensland increase the most, due to the stronger percentage increase in contract prices compared with New South Wales and South Australia. The WEC for the NSLP in South Australia increases despite the decline in base contract prices between 2021-22 and 2022-23 – this is because the decrease in base contract prices is more than offset by the increase cap contract prices and the decline in spot price outcomes during daylight hours when the NSLP demand is at its lowest (resulting in large difference payments).

As discussed earlier, the WEC for each tariff class is unlikely to decrease (or increase for that matter) 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 4.30 shows the trend in WEC over the past DMO determinations. Despite the increase in WECs in 2022-23, they remain less than the WECs estimated for 2019-20 and 2020-21. Although this may change for the Final Determination - depending on movements in contract prices between the Draft and Final Determinations.

Figure 4.30 Estimated WEC ($/MWh, nominal) for 2022-23 at the regional reference node in comparison with WECs from previous determinations



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[10]) 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 TFS, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen. For the Draft Determination, ACIL Allen assesses the most up to date information available including 'non-binding' scheme parameters from the CER, and this information will be revised for the Final Determination when the CER has published the final binding parameters

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required 2022 and 2023 calendar years, with the costs averaged to estimate the 2022-23 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 2022 and 2023 from brokers TFS

— estimated Renewable Power Percentages (RPP) values for 2022 and 2023 of 18.54 per cent[11]

[10] 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.

[11] The RPP values for 2022 and 2023 are based on the CER's published RPP for 2021, and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2022 and 2023. Any subsequent updates published by the CER will be included in the Final Determination.

- non-binding Small-scale Technology Percentage (STP) values for 2022 and 2023 of 22.40 and 21.15 per cent respectively, as published by CER[12]
- CER clearing house price[13] for 2022 and 2023 for Small-scale Technology Certificates (STCs) of $40/MWh.

The STPs for 2022 and 2023 used in the Draft Determination are the non-binding values published by the CER. Based on our interpretation of the three consultant reports published by the CER estimating the rooftop PV uptake[14] (an input in calculating the STPs), it appears the projected uptake rates for 2022 and 2023 are similar to recently observed uptake rates. However, the STPs also take into account the diminishing deeming period, which in net terms results in lower STPs when compared with the 2021-22 Final Determination. As we approach the end of the SRES (2030), unless there is a reasonable increase in the installation rate of rooftop PV systems, it is likely that the diminishing deeming period will more than offset an increase in uptake rate when calculating the STP in future years.

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 TFS.

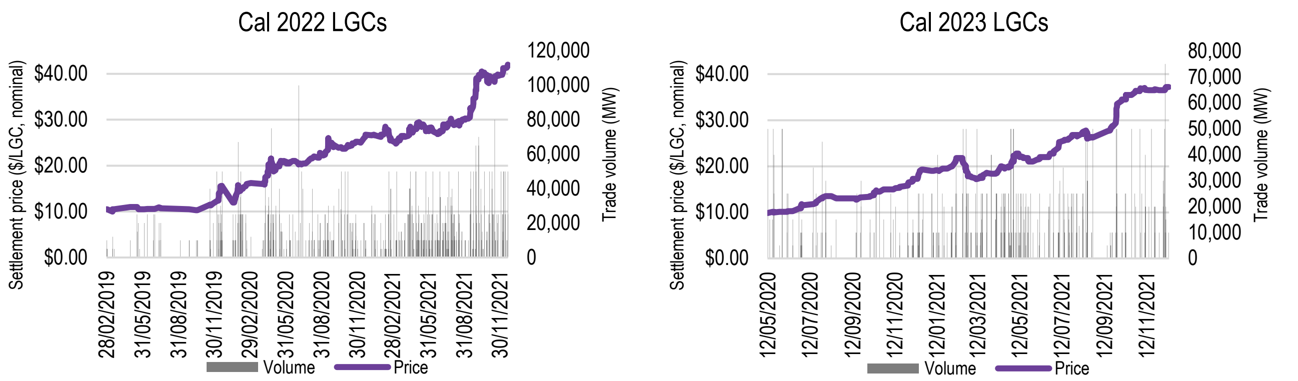
The LGC price used in assessing the cost of the scheme for 2022-23 is found by taking the trade-weighted average of the forward prices for the 2022 and 2023 calendar years, respectively, since the contracts commenced trading. This is typically about 2.5 years prior to the commencement of the compliance year (see Figure 4.31). The average LGC prices calculated from the TFS data are $26.47/MWh for 2022 and $22.36/MWh for 2023**.**

[12] Any subsequent updates published by the CER will be included in the Final Determination.

[13] 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.

[14] http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage/small-scale-technology-percentage-modelling-reports

Figure 4.31 LGC prices for 2022 and 2023 for 2022-23 ($/LGC, nominal)



Source: ACIL Allen analysis of TFS data up to 11 January 2022

The RPP value for 2021 was set by the CER on 1 April 2021 at 18.54 per cent. The RPP values for 2022 and 2023 is estimated by using the mandated target for 2022 and 2023 of 33 TWh and the CER's published cumulative adjustment and estimate of electricity acquisitions in 2021 of 175.9 TWh. In other words, ACIL Allen has assumed electricity acquisitions remain constant in 2022 and 2023, and hence the RPP values for 2022 and 2023 are also 18.54 per cent.

Key elements of the 2022 and 2023 RPP estimation are shown in Table 4.5.

Table 4.5 Estimating the 2022 and 2023 RPP values

	2022	2023
LRET target, MWh (CER)	32,616,792	32,616,792
Relevant acquisitions minus exemptions, MWh (CER)	175,900,000	175,900,000
Estimated RPP	18.54%	18.54%

Source: ACIL Allen analysis of CER data

ACIL Allen calculates the cost of complying with the LRET in 2022 and 2023 by multiplying the RPP values for 2022 and 2023 by the trade volume weighted average LGC prices for 2022 and 2023, respectively. The cost of complying with the LRET in 2022-23 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $4.53/MWh in 2022-23 as shown in Table 4.6.

Table 4.6 Estimated cost of LRET – 2022-23

	2022	2023	Cost of LRET 2022-23
RPP %	18.54%	18.54%	
Trade weighted average LGC price ($/LGC, nominal)	$26.47	$22.36	
Cost of LRET ($/MWh, nominal)	**$4.91**	**$4.15**	**$4.53**

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 2022-23.

ACIL Allen estimates the cost of complying with SRES to be $8.71/MWh in 2022-23 as set out in Table 4.7.

Table 4.7 Estimated cost of SRES – 2022-23

	2022	2023	Cost of SRES 2022-23
STP %	22.40%	21.15%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	**$8.96**	**$8.46**	**$8.71**

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 2022-23 as set out in Table 4.8.

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

Table 4.8 Total renewable energy policy costs ($/MWh, nominal) – 2022-23

	2021-22	2022-23
LRET	$4.22	$4.53
SRES	$11.52	$8.71
Total	**$15.74**	**$13.24**

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 2022 and 2023 of 9 and 9.5 per cent respectively, as published by IPART

— Historical Energy Savings Certificate (ESC) market forward prices for 2022 and 2023 from brokers TFS.

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 2022-23, as set out in Table 4.9. The 2022-23 estimate of $3.39/MWh is up from the 2021-22 estimate of $2.48/MWh – reflecting higher certificate prices and an increase in the ESS target.

Table 4.9 Estimated cost of ESS ($/MWh, nominal) – 2022-23

	2022	2023	Cost of ESS 2022-23
ESS target	9.0%	9.5%	
Average ESC price ($/MWh, nominal)	$36.42	$36.85	
Cost of ESS ($/MWh, nominal)	$3.28	$3.50	$3.39

Source: IPART, TFS data up to 11 January 2022

4.3.5 New South Wales Peak Demand Reduction Scheme (PDRS)

To estimate the cost of complying with the PDRS for 2022-23, ACIL Allen has used the following elements:

— The peak demand reduction target for 2022-23 of 0.5 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 2022-23 of 13,658 MW as published by AEMO in its 2021 ESOO, this equates to 68,288 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 $3.23/PRC. As PRC trade volume and price data becomes available, we propose to estimate the PRC price as the trade volume weighted average price.

— The annual energy requirements for New South Wales in 2022-23 of 60,671 GWh as published by AEMO in its 2021 ESOO.

The estimated cost of the PDRS for 2022-23 is $0.22/MWh.

Table 4.10 Estimated cost of PDRS ($/MWh, nominal) – 2022-23

Item	Value
PRC price ($/PRC, nominal) per 0.1kW of peak demand reduction capacity averaged across one hour	$3.23
PDRS target (percentage reduction in peak demand)	0.5%
PDRS target (kW reduction in peak demand)	68,288
PRC target (certificates)	4,097,297
Total cost of PDRS ($, nominal)	$13,228,418
Cost of PDRS per certificate ($/PRC, nominal)	$0.10
NSW operational energy requirements (GWh)	60,671
Cost of PDRS ($/MWh)	**$0.22**

Source: ACIL Allen analysis

4.3.6 South Australia Retailer Energy Productivity Scheme (REPS)

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

In the AEMC's 2021 price trends report, the cost of the REPS is assumed to be the same as the cost of the REES in previous years. The estimated cost is $2.50/MWh.

Given the limited availability of public data on the cost of meeting the REPS at this point in time and that the cost as estimated by AEMC is a very small component of the overall retail bill (less than one per cent), ACIL Allen proposes to use $2.50/MWh as the cost of the REPS.

4.4 Estimation of other energy costs

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

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

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA)[15], DER and IT system upgrades for 5MS.

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2021-22* our estimate of the fees for 2022-23 are $0.67/MWh (up from $0.49/MWh for 2021-22 in DMO 3). The breakdown of total fees is shown in Table 4.11. The majority of the increase in fees relates to the inclusion of IT upgrade costs for 5MS.

Table 4.11 NEM management fees ($/MWh, nominal) – 2022-23

Cost category	2021-22	2022-23
NEM fees (admin, registration, etc.)	$0.37	$0.40
FRC - electricity	$0.078	$0.081
ECA - electricity	$0.040	$0.040
DER fee	$0.000	$0.026
IT upgrade and 5MS/GS compliance	$0.00	$0.123
Total NEM management fees	**$0.49**	**$0.67**

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 11 January 2022) of available NEM ancillary services data as a basis for 2022-23, 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 and South Australia. However, there has been quite an increase in Queensland.

[15] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2021-22* 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.

There has been a noticeable increase in weekly ancillary service costs in Queensland over the past two quarters as a result of upgrade works associated with the QNI giving rise to price separation between the two regions.

Table 4.12 Ancillary services ($/MWh, nominal) – 2022-23

Region	2021-22	2022-23
Queensland	$0.42	$1.26
New South Wales	$0.28	$0.32
South Australia	$1.02	$1.04

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 $8,021

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 $8,021/42 = $190.97/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 $190.97 gives $0.55/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 – 2022-23

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$104.22	$50.33	$49.04
Participant Risk Adjustment Factor	1.6048	1.2677	1.3404
OS Volatility factor	1.50	1.35	1.41
PM Volatility factor	2.71	1.81	1.88
OSL	$12,236	$3,733	$4,131
PML	$2,447	$747	$826
MCL	$14,683	$4,480	$4,957
Average MCL		$8,021	
AEMO prudential cost ($/MWh, nominal)		**$0.55**	

Source: ACIL Allen analysis of AEMO data

Table 4.14 AEMO prudential costs for Ausgrid NSLP – 2022-23

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$68.46	$76.22	$46.47
Participant Risk Adjustment Factor	1.3043	1.2697	0.9151
OS Volatility factor	1.61	1.40	1.36
PM Volatility factor	3.45	1.98	2.04
OSL	$6,321	$5,877	$2,130
PML	$1,264	$1,175	$426
MCL	$7,585	$7,053	$2,556
Average MCL		$5,739	
AEMO prudential cost ($/MWh, nominal)		**$0.39**	

Source: ACIL Allen analysis of AEMO data

Table 4.15 AEMO prudential costs for Endeavour NSLP – 2022-23

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$68.46	$76.22	$46.47
Participant Risk Adjustment Factor	1.4048	1.1095	1.0142
OS Volatility factor	1.61	1.40	1.36
PM Volatility factor	3.45	1.98	2.04
OSL	$7,066	$4,801	$2,485
PML	$1,413	$960	$497

Factor	Summer	Winter	Shoulder
MCL	$8,479	$5,762	$2,982
Average MCL		$5,741	
AEMO prudential cost ($/MWh, nominal)		**$0.39**	

Source: ACIL Allen analysis of AEMO data

Table 4.16 AEMO prudential costs for Essential NSLP – 2022-23

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$68.46	$76.22	$46.47
Participant Risk Adjustment Factor	1.1997	1.1018	1.1207
OS Volatility factor	1.61	1.40	1.36
PM Volatility factor	3.45	1.98	2.04
OSL	$5,576	$4,751	$2,886
PML	$1,115	$950	$577
MCL	$6,692	$5,701	$3,464
Average MCL		$5,288	
AEMO prudential cost ($/MWh, nominal)		**$0.36**	

Source: ACIL Allen analysis of AEMO data

Table 4.17 AEMO prudential costs for SAPN NSLP – 2022-23

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$115.24	$85.89	$53.64
Participant Risk Adjustment Factor	2.3391	1.3329	1.2810
OS Volatility factor	1.84	1.51	1.51
PM Volatility factor	4.95	2.19	1.89
OSL	$29,205	$7,683	$4,521
PML	$5,841	$1,537	$904
MCL	$35,046	$9,220	$5,426
Average MCL		$16,524	
AEMO prudential cost ($/MWh, nominal)		**$1.13**	

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 current money market rate is 0.10 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 (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 9 percent on average for a base contract, 14 percent for a peak contract and 19 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, $13,600 for a peak contract and $5,900 for a cap contract
— the spot isolation rate currently set at $1,500 for a base contract, $1,500 for a peak 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 7.22 per cent but adjusted for an assumed 0.10 per cent return on cash lodged with the clearing (giving a net funding cost of 7.12 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 2022-23

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$54.02	$25,000	$0.72
Peak	$79.21	$26,000	$1.75
Cap	$11.25	$12,000	$0.35

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.19 Hedge Prudential funding costs by contract type – New South Wales 2022-23

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$62.03	$28,000	$0.81
Peak	$89.68	$25,000	$1.69
Cap	$12.52	$14,000	$0.41

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.20 Hedge Prudential funding costs by contract type – South Australia 2022-23

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$48.39	$38,000	$1.10

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Peak	$76.04	$43,000	$2.90
Cap	$12.07	$19,000	$0.55

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 – 2022-23

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.72	1.1219	$0.81
Peak	$1.75	0.0184	$0.03
Cap	$0.35	1.5771	$0.55
Total cost		**$1.39**	

Source: ACIL Allen analysis

Table 4.22 Hedge Prudential funding costs for Ausgrid NSLP – 2022-23

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.81	0.9244	$0.75
Peak	$1.69	0.0132	$0.02
Cap	$0.41	2.2316	$0.91
Total cost		**$1.68**	

Source: ACIL Allen analysis

Table 4.23 Hedge Prudential funding costs for Endeavour NSLP – 2022-23

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.81	0.9082	$0.74
Peak	$1.69	0.0231	$0.04
Cap	$0.41	1.8036	$0.73
Total cost		**$1.51**	

Source: ACIL Allen analysis

Table 4.24 Hedge Prudential funding costs for Essential NSLP – 2022-23

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.81	0.9050	$0.73
Peak	$1.69	0.0441	$0.07
Cap	$0.41	1.3087	$0.53
Total cost		**$1.34**	

Source: ACIL Allen analysis

Table 4.25 Hedge Prudential funding costs for SAPN NSLP – 2022-23

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.10	0.9104	$1.00
Peak	$2.90	0.0262	$0.08
Cap	$0.55	2.5965	$1.43
Total cost		**$2.51**	

Source: ACIL Allen analysis

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2022-23 as set out in Table 4.26. Prudential costs for 2022-23 are slightly higher than 2021-22 due to lower higher prices and higher expected price volatility across 2022-23.

Table 4.26 Total prudential costs ($/MWh, nominal) – 2022-23

Jurisdiction	2021-22	2022-23
Ausgrid NSLP	$1.94	$2.07
Endeavour NSLP	$1.81	$1.90
Essential NSLP	$1.59	$1.70
Energex NSLP	$1.66	$1.94
SAPN NSLP	$3.60	$3.64

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 Draft Determination (and this will be updated for the Final Determination).

AEMO has activated the RERT twice for the 12-month period prior to the Draft Determination. The first activation occurred on 17 December 2020 for the New South Wales region due to a forecast Lack of Reserve Condition 2. In February 2021, AEMO reported the payments for this activation to be $200,570. When dividing this value by the total energy requirements in New South Wales, the cost of the RERT is less than about 0.3 of a cent per MWh (or $0.00 when rounded to the nearest cent). It is worth noting that this was included in the 2021-22 Final Determination, and will 'drop out' of the 2022-23 estimates for the Final Determination since the event will be more than 12 months in the past.

AEMO also activated the RERT for 15 MW in Queensland on 25 May 2021, in response to a forecast Lack of Reserve (LOR) 2 condition which developed into an actual LOR 2 and a forecast LOR 3 condition. This was the result of the loss of several generating units due to the fire at unit 4 of Callide. AEMO reported the costs of this activation to be $452,881. When dividing this value by the total energy requirements in Queensland, the cost of the RERT is about one cent per MWh.

There has been no activation of the RERT in South Australia over the past 12 months, and hence the RERT costs are set to $0.00/MWh.

4.4.5 Retailer Reliability Obligation

The RRO is currently not triggered for 2022-23, and hence we are not required to account for the RRO in the wholesale costs for 2022-23.

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 Draft Determination) and divided by the corresponding annual regional customer energy.

Direction costs in South Australia over the past 12 months equate to $5.02/MWh.

Direction costs in South Australia have increased as a result of very low spot prices during daylight hours and increased gas prices reducing the amount of synchronous generation below required levels. It is expected that direction costs in South Australia will decrease now that the newly installed synchronous condensers have completed their commissioning phase, and AEMO reduces the minimum requirement of the continuous operation of gas-fired units from four two to ensure power system security. These will be updated for the Final Determination upon updated data being published by AEMO.

4.4.7 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.27 and Table 4.28, for the 2022-23 Draft Determination and is compared with the costs for 2021-22.

Table 4.27 Total of other costs ($/MWh, nominal) – Energex NSLP – 2022-23

Cost category	2021-22	2022-23
NEM management fees	$0.49	$0.67
Ancillary services	$0.42	$1.26
Hedge and pool prudential costs	$1.66	$1.94
Reserve and Emergency Reserve Trader costs	$0.00	$0.01
AEMO Direction costs	N/A	$0.00
Total	**$2.57**	**$3.88**

Source: ACIL Allen analysis

Table 4.28 Total of other costs ($/MWh, nominal) – Ausgrid NSLP – 2022-23

Cost category	2021-22	2022-23
NEM management fees	$0.49	$0.67
Ancillary services	$0.28	$0.32
Hedge and pool prudential costs	$1.94	$2.07
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	N/A	$0.00
Total	**$2.71**	**$3.06**

Source: ACIL Allen analysis

Table 4.29 Total of other costs ($/MWh, nominal) – Endeavour NSLP – 2022-23

Cost category	2021-22	2022-23
NEM management fees	$0.49	$0.67
Ancillary services	$0.28	$0.32
Hedge and pool prudential costs	$1.81	$1.90
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	N/A	$0.00
Total	**$2.58**	**$2.89**

Source: ACIL Allen analysis

Table 4.30 Total of other costs ($/MWh, nominal) – Essential NSLP – 2022-23

Cost category	2021-22	2022-23
NEM management fees	$0.49	$0.67
Ancillary services	$0.28	$0.32
Hedge and pool prudential costs	$1.59	$1.70
Reserve and Emergency Reserve Trader costs	$0.00	$0.00

Cost category	2021-22	2022-23
AEMO Direction costs	N/A	$0.00
Total	**$2.36**	**$2.69**

Source: ACIL Allen analysis

Table 4.31 Total of other costs ($/MWh, nominal) – SAPN NSLP – 2022-23

Cost category	2021-22	2022-23
NEM management fees	$0.49	$0.67
Ancillary services	$1.02	$1.04
Hedge and pool prudential costs	$3.60	$3.64
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	N/A	$5.02
Total	**$5.11**	**$10.37**

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.

For the Draft Determination, the losses for 2022-23 are based on the estimates for 2021-22 Final Determination. Although AEMO recently published the preliminary MLF estimates for 2022-23 in late December 2021 these have not been included in the Draft Determination given their preliminary nature.

The MLFs and DLFs used to estimate losses for the Final Determination for 2022-23 will be based on the 2022-23 MLFs and DLFs to be published by AEMO in early April 2022.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2022-23 is shown in Table 4.32.

Table 4.32 Estimated transmission and distribution losses

	2021-22			2022-23		
	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	4.84%	0.34%	1.052	4.84%	0.34%	1.052
Endeavour - NSLP	6.82%	-0.74%	1.060	6.82%	-0.74%	1.060
Essential - NSLP	6.37%	-1.76%	1.045	6.37%	-1.76%	1.045
Ausgrid - CLP1	5.19%	0.34%	1.055	5.19%	0.34%	1.055
Ausgrid - CLP2	5.19%	0.34%	1.055	5.19%	0.34%	1.055
Endeavour - CLP	6.82%	-0.74%	1.060	6.82%	-0.74%	1.060
Essential - CLP	6.37%	-1.76%	1.045	6.37%	-1.76%	1.045
Energex - NSLP	5.87%	0.53%	1.064	5.87%	0.53%	1.064
Energex – CLP31	5.87%	0.53%	1.064	5.87%	0.53%	1.064
Energex – CLP33	5.87%	0.53%	1.064	5.87%	0.53%	1.064
SAPN - NSLP	11.70%	0.12%	1.118	11.70%	0.12%	1.118
SAPN - CLP	11.70%	0.12%	1.118	11.70%	0.12%	1.118

Source: ACIL Allen analysis of AEMO data

As described by AEMO[16], 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)*

[16] 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 2022-23 total energy costs (TEC) for the Draft Determination for each of the profiles are presented in Table 4.32 and Table 4.34.

Table 4.33 Estimated TEC for 2022-23 ($/MWh, nominal) – Draft Determination

Profile	2021-22 Total energy costs at the customer terminal ($/MWh, nominal)	2022-23 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2021-22 to 2022-23 ($/MWh, nominal)	Change from 2021-22 to 2022-23 (%, nominal)
Ausgrid - NSLP	$107.11	$115.67	$8.56	7.99%
Endeavour - NSLP	$107.58	$116.80	$9.22	8.57%
Essential - NSLP	$99.38	$109.14	$9.76	9.82%
Ausgrid - CLP1	$79.66	$81.82	$2.16	2.71%
Ausgrid - CLP2	$76.69	$81.44	$4.75	6.19%
Endeavour - CLP	$102.60	$108.97	$6.37	6.21%
Essential - CLP	$86.34	$85.24	($1.10)	-1.27%
Energex - NSLP	$90.78	$106.56	$15.78	17.38%
Energex – CLP31	$75.59	$86.83	$11.24	14.87%
Energex – CLP33	$77.93	$84.10	$6.17	7.92%
SAPN - NSLP	$139.86	$145.86	$6.00	4.29%
SAPN - CLP	$93.21	$85.38	($7.83)	-8.40%

Source: ACIL Allen analysis

Table 4.34 Estimated TEC for 2022-23 Draft Determination ($/MWh, nominal)

Profile	WEC at regional reference node ($/MWh, nominal)	Other wholesale costs at regional reference node ($/MWh, nominal)	Network loss factor	Wholesale network losses ($/MWh, nominal)	Total wholesale costs at the customer terminal ($/MWh, nominal)	LRET costs at regional reference node ($/MWh, nominal)	SRES costs at regional reference node ($/MWh, nominal)	Other environmental costs at regional reference node ($/MWh, nominal)	Environmental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$90.04	$3.06	1.052	$4.84	$97.94	$4.53	$8.71	$3.61	$0.88	$17.73	$115.67
Endeavour - NSLP	$90.45	$2.89	1.060	$5.60	$98.94	$4.53	$8.71	$3.61	$1.01	$17.86	$116.80
Essential - NSLP	$84.90	$2.69	1.045	$3.94	$91.53	$4.53	$8.71	$3.61	$0.76	$17.61	$109.14
Ausgrid - CLP1	$57.64	$3.06	1.055	$3.34	$64.04	$4.53	$8.71	$3.61	$0.93	$17.78	$81.82
Ausgrid - CLP2	$57.28	$3.06	1.055	$3.32	$63.66	$4.53	$8.71	$3.61	$0.93	$17.78	$81.44
Endeavour - CLP	$83.06	$2.89	1.060	$5.16	$91.11	$4.53	$8.71	$3.61	$1.01	$17.86	$108.97
Essential - CLP	$62.03	$2.69	1.045	$2.91	$67.63	$4.53	$8.71	$3.61	$0.76	$17.61	$85.24
Energex - NSLP	$83.03	$3.88	1.064	$5.56	$92.47	$4.53	$8.71	$0.00	$0.85	$14.09	$106.56
Energex - CLP1	$64.48	$3.88	1.064	$4.38	$72.74	$4.53	$8.71	$0.00	$0.85	$14.09	$86.83
Energex - CLP2	$61.92	$3.88	1.064	$4.21	$70.01	$4.53	$8.71	$0.00	$0.85	$14.09	$84.10
SAPN - NSLP	$104.35	$10.37	1.118	$13.54	$128.26	$4.53	$8.71	$2.50	$1.86	$17.60	$145.86
SAPN - CLP	$50.26	$10.37	1.118	$7.15	$67.78	$4.53	$8.71	$2.50	$1.86	$17.60	$85.38

Source: ACIL Allen analysis

AEMC 2021 Residential electricity price trends report

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The AEMC's report, *2021 Residential Electricity Price Trends,* was released in November 2021 (the AEMC report). The AEMC report does not form part of any regulatory determination process but has the purpose of providing consumers and governments with an understanding of the cost components of the electricity supply chain and the expected trends of the components for the majority of customers in each region.

Provided below are some key differences in the approach adopted by the AEMC compared with ACIL Allen's methodology – noting that the AEMC report provides a high-level summary of the methodology.

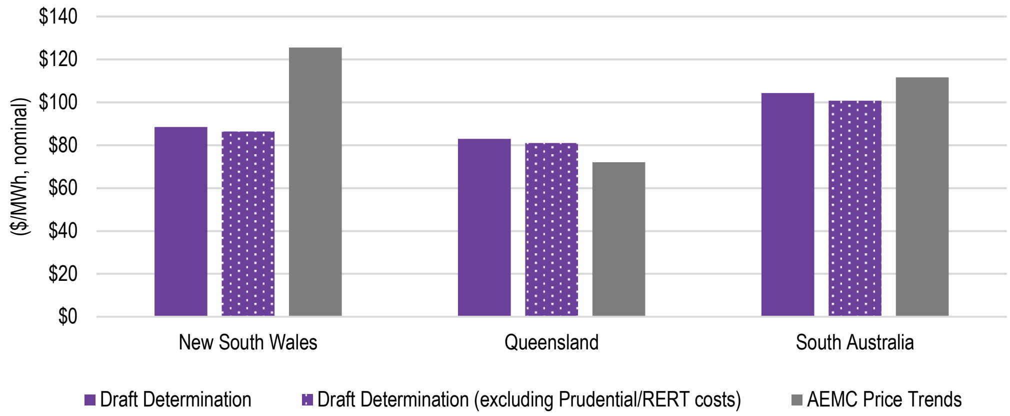
A.1 Wholesale energy costs

The AEMC's approach to estimating wholesale energy costs is broadly similar to the approach adopted by ACIL Allen. However, there are some key differences:

- Demand profiles:
  - It is ACIL Allen's understanding the AEMC does not adjust the historic NSLPs to take into account changes in the shape in the future due to further uptake of rooftop PV.
  - If this understanding is correct, then not adjusting the profiles will result in lower wholesale costs estimates (all other things equal).
  - It also appears that the AEMC aggregate the NSLPs within the New South Wales region to produce a state-based NSLP, and in the case of Queensland aggregate the NSLP and control load produce an aggregate WEC.
- <u>Spot market modelling:</u>
  - The AEMC appears to use historic bids (offer curves) when undertaking its spot price modelling. These appear to be adjusted for assumed changes in underlying costs (such as fuel prices) from the latest available ESOO. ACIL Allen's *PowerMark* uses dynamic bidding (based on game theory) to account of changes in bidding behaviour incentivised by changes in market conditions (such as the addition of renewable capacity between now and 2022-23, as well as changes in underlying costs). AEMC acknowledges that bidding behaviour may change in the future and therefore affect their results.
- <u>Hedge portfolio:</u>
  - AEMC use a portfolio of quarterly base, peak and cap hedges to cover the NSLP, as does ACIL Allen, but do not provide the mix of these products or the extent that the portfolio of hedges covers the NSLP profile.
- <u>Hedge or contract prices:</u>
  - AEMC use a 2-year build-up of hedges using ASX Energy contract price data up to October 2021.
  - It appears AEMC's portfolio build-up is assumed to be completed by April 2022, as is ACIL Allen's for the Final Determination.

    - This means that six months of actual ASX Energy prices are unable to be included in the AEMC analysis for 2022-23 (with the six-month period being October 2021 to end of March 2022).
    - AEMC do not use the observable trade volumes as the weights to calculate the weighted average cost of each product, and instead use an exponential build-up of the portfolio of hedges.
    - For the six months of missing ASX Energy contract data, the AEMC have used their modelled spot price outcomes as a substitute for contract prices. This means that in deriving the final estimate of the contract prices for each quarterly product for 2022-23, AEMC is missing at least, an assumed, 60 per cent of ASX Energy trade volumes and corresponding prices, and is using their modelled spot prices to represent the missing 60 per cent of trade volumes and contract prices.
    - Rather than pre-specifying or forcing a particular pattern in the hedge book build up, ACIL Allen uses all trades back to the first trade recorded by ASX Energy for the given product, which generally more closely reflects, in practice, how retailers build up their portfolio of hedging contracts over time. We have noted in earlier reports that the cumulative shape in actual volume of trades can be quite different to an exponential curve in some years.
    - Forcing an exponential book build and using a different weighting between actual ASX Energy prices and modelled spot prices could yield a very different result.
    - This is the key difference between our methodology and the AEMC methodology for estimating the WEC:
        - We use actual contract data because the final estimates of the WEC will be derived in April 2022 for the Final Determination, whereas AEMC had to make their final estimates at the beginning of October 2021 (so in effect the AEMC has had to fill in a contract price and volume data gap of six months with projected spot prices). For the Draft Determination we do not explicitly predict the volume or price level of trades in contracts between January 2022 and April 2022 – instead, we simply close the contract data as of 11 January 2022.
- Wholesale costs:
    - That all said, the projected wholesale costs presented in the AEMC report for 2022-23 are quite similar those of this Draft Determination for Queensland and South Australia.
    - For New South Wales, the AEMC wholesale costs are about $40/MWh higher than our estimates. This is a substantial difference. Further, the AEMC wholesale costs for New South Wales are over $50/MWh higher than their estimates for Queensland. It could be the case that the AEMC are projecting spot prices in New South Wales to be much higher than the current ASX Energy contract prices. This implies that prices in New South Wales separate away substantially from those of Queensland on an annual average basis. Alternatively, it could be the case that the AEMC analysis assumes a much larger change in the shape of the NSLPs in New South Wales – becoming much more peaky and hence more expensive to hedge.

Figure A.1 Total wholesale costs ($/MWh, nominal)



Source: ACIL Allen analysis and AEMC

- ACIL Allen maintains the view that there is no net benefit in filling in the missing contract data for the Draft Determination since the actual data will be available for the Final Determination. The wholesale costs estimated for the Final Determination may well be different to those of the Draft Determination depending on volume and price level of trades in contracts that occur between the Draft and Final Determination. If actual contracts continued to be traded at volumes observed in previous years, and contract prices increase further, between the Draft Determination and the Final Determination, then a further increase in the WECs would be expected for the Final Determination.
- It is also worth noting that the AEMC revised upwards its wholesale cost estimates for 2021-22 in its latest report (compared with its December 2020 report). For example, for south-east Queensland, the wholesale cost estimates for 2021-22 have increased from about $61/MWh to $85/MWh. This is important to note because one of the headlines from the latest AEMC report is that prices in Queensland will decline between 2021-22 and 2022-23 due to reducing wholesale costs – which is in contrast to our analysis.

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