ACIL ALLEN CONSULTING

REPORT TO

AUSTRALIAN ENERGY REGULATOR

8 FEBRUARY 2021

DEFAULT MARKET OFFER 2021-22

WHOLESALE ENERGY AND ENVIRONMENTAL COSTS

ESTIMATES FOR DMO 3 DRAFT DETERMINATION

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DEFAULT MARKET OFFER 2021-22: WHOLESALE ENERGY AND ENVIRONMENTAL COSTS: ESTIMATES FOR DMO 3 DRAFT DETERMINATION, ACIL ALLEN, FEBRUARY 2021

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EXECUTIVE SUMMARY

ACIL Allen Consulting (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 2021-22 (DMO 3). 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 relates to Phase 2 of our engagement, and provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination, using the methodology proposed in our Phase 1 methodology review report to the AER, as well as taking into account stakeholder feedback in response to the AER's Position Paper.

Summary of estimated energy costs

ACIL Allen's estimates of the 2021-22 total wholesale energy costs, environmental costs and total energy costs (TEC) for the Draft Determination for each of the regional tariff profiles for 2021-22 are presented in Table ES 1.

TABLE ES 1 ESTIMATED ENERGY COST COMPONENTS FOR 2021-22 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	$87.06	$16.65	$103.71
Endeavour - NSLP	$87.80	$16.84	$104.64
Essential - NSLP	$81.88	$16.73	$98.61
Ausgrid - CLP1	$62.26	$16.70	$78.96
Ausgrid - CLP2	$60.95	$16.70	$77.65
Endeavour - CLP	$83.04	$16.84	$99.88
Essential - CLP	$73.11	$16.73	$89.84
Energex - NSLP	$74.86	$14.35	$89.21
Energex – CLP31	$57.07	$14.35	$71.42
Energex – CLP33	$60.05	$14.35	$74.40
SAPN - NSLP	$125.38	$17.78	$143.16
SAPN - CLP	$82.35	$17.78	$100.13

SOURCE: ACIL ALLEN ANALYSIS

The change, in $/MWh and percentage terms, in the estimated total energy costs between 2020-21 DMO 2 Final Determination and 2021-22 DMO 3 Draft Determination are shown in Table ES 2.

TABLE ES 2 CHANGE IN ESTIMATED TOTAL ENERGY COST BETWEEN 2020-21 AND 2021-22 ($/MWH, NOMINAL AND %) - DRAFT DETERMINATION

Profile	2020-21 Total energy costs at the customer terminal ($/MWh, nominal)	2021-22 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2020-21 to 2021-22 ($/MWh, nominal)	Change from 2020-21 to 2021-22 (%, nominal)
Ausgrid - NSLP	$128.23	$103.71	($24.52)	-19.12%
Endeavour - NSLP	$129.63	$104.64	($24.99)	-19.28%
Essential - NSLP	$120.75	$98.61	($22.14)	-18.34%
Ausgrid - CLP1	$91.24	$78.96	($12.28)	-13.46%
Ausgrid - CLP2	$89.33	$77.65	($11.68)	-13.08%
Endeavour - CLP	$121.28	$99.88	($21.40)	-17.65%
Essential - CLP	$105.15	$89.84	($15.31)	-14.56%
Energex - NSLP	$106.59	$89.21	($17.38)	-16.31%
Energex – CLP31	$87.39	$71.42	($15.97)	-18.27%
Energex – CLP33	$89.16	$74.40	($14.76)	-16.55%
SAPN - NSLP	$172.69	$143.16	($29.53)	-17.10%
SAPN - CLP	$111.72	$100.13	($11.59)	-10.37%

SOURCE: ACIL ALLEN ANALYSIS

The change, in percentage terms, in the estimated energy cost between 2020-21 DMO 2 Final Determination and 2021-22 DMO 3 Draft Determination are set out in Table ES 3.

TABLE ES 3 CHANGE IN ESTIMATED ENERGY COST COMPONENTS BETWEEN 2020-21 AND 2021-22 (%) - DRAFT DETERMINATION

Profile	Change in total wholesale energy cost (%)	Change in total environmental cost (%)	Change in total energy cost (TEC) (%)
Ausgrid - NSLP	-21.61%	-3.03%	-19.12%
Endeavour - NSLP	-21.80%	-3.00%	-19.28%
Essential - NSLP	-20.89%	-3.01%	-18.34%
Ausgrid - CLP1	-15.89%	-3.02%	-13.46%
Ausgrid - CLP2	-15.48%	-3.02%	-13.08%
Endeavour - CLP	-20.09%	-3.00%	-17.65%
Essential - CLP	-16.83%	-3.01%	-14.56%
Energex - NSLP	-18.18%	-4.97%	-16.31%
Energex – CLP31	-21.05%	-4.97%	-18.27%
Energex – CLP33	-18.92%	-4.97%	-16.55%
SAPN - NSLP	-18.65%	-4.25%	-17.10%
SAPN - CLP	-11.59%	-4.25%	-10.37%

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 whole energy costs are the change in contract prices and shape of the load profiles. Compared with the 2020-21, futures base contract prices for 2021-22, on an annualised and trade weighted basis to date, have:
    - decreased by about $12.60/MWh for Queensland
    - decreased by about $13.00/MWh for New South Wales
    - decreased by about $20.30/MWh for South Australia.
  - The market is clearly expecting a continued strong decline in price outcomes due to the strong increase in renewable investment coming on-line between 2020-21 and 2021-22.
  - If the contract prices continue to decrease between this Draft Determination and the Final Determination, then the WECs may well decline further.
  - **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. Ancillary service costs are estimated by the most recent 52 weeks of actual cost data as published by AEMO. Generally, there has been a decrease in weekly ancillary service costs as a result of additional supply being commissioned that can offer services to this relatively small market. This results in a reasonable decrease in ancillary service costs in Queensland and New South Wales. However, there have been occasions over the past 12 months (in early 2020) in which the market in South Australia islanded from the remainder of the market, and during these periods the cost of ancillary services increased substantially – leading to an overall increase across the year for South Australia. Providing there are no islanding events between this Draft Determination and the Final Determination in South Australia, the ancillary service costs will likely decrease in South Australia for the Final Determination.

— **Environmental costs:** environmental costs are projected to fall slightly across all regions. The decline is primarily driven by a projected decline in the cost of the LRET between 2020-21 and 2021-22 of about 20 per cent (or $0.98/MWh) as a result of declining LGC forward prices. LGC forward prices have fallen due to the surge in investment in renewables over recent years. The cost of the SRES is projected to increase by just under three per cent (or $0.27/MWh), with the expectation that small-scale installations will increase slightly in 2022. The cost variations by region mainly result from differences in jurisdictional energy efficiency schemes.

1 INTRODUCTION

ACIL Allen Consulting (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 2021-22 (DMO 3).

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).

ACIL Allen's work is broadly divided into two phases:

- **Phase 1**: Review and assessment of methodology
  - The services in this phase include reviewing the methodology used to estimate the underlying wholesale and environmental cost inputs for the 2020-21 DMO (DMO 2), and clearly set out any changes, refinements, or considerations to the existing methodology for DMO 3. The deliverable in this phase was ACIL Allen's methodology review report which formed part of the Position Paper for DMO 3 (the Position Paper) published by the AER.
- **Phase 2**: Estimating the underlying costs to inform the DMO 2021-22 determination
  - The services in this phase include estimating the underlying cost inputs for the DMO 3 determination based on the methodology refined in Phase 1. The deliverables in this phase form part of the draft DMO 3 prices (Draft Determination) and the final DMO prices (Final Determination).

This report relates to Phase 2 of our engagement, and provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination for DMO 3, using the methodology proposed in our Phase 1 methodology review report, and including some refinements to address stakeholder issues raised in submissions to the DMO 3 Position Paper.

The report is presented as follows:

- Chapter 2 summarises our methodology.
- Chapter 3 provides responses to submissions made by various parties following the release of the AER's *Position Paper: Default Market Offer Price 2021-22* (October 2020), where those submissions refer to the methodology used to estimate the wholesale, environmental, and other costs.
- Chapter 4 summarises our derivation of the energy cost estimates.
- Finally, Appendix A summarises our high-level comparison with the AEMC's 2020 Residential Electricity Price Trends Report released in December 2020.

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 3, including refinements based on stakeholder feedback from the Position Paper.

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:

— Wholesale energy costs (WEC) for various demand profiles

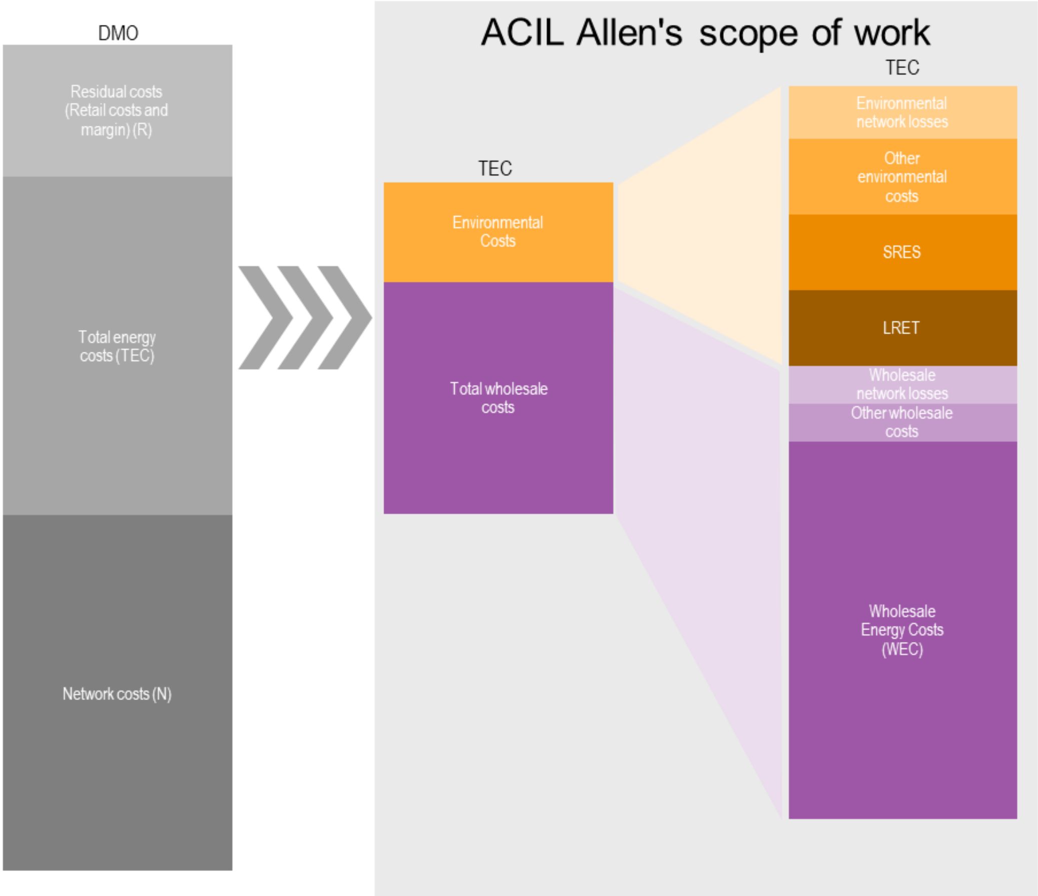
— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET)

— 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 COMPONENTS OF TEC



SOURCE: ACIL ALLEN

2.3 Methodology

The ACIL Allen methodology adopted for DMO 3 (and DMO 2) 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:

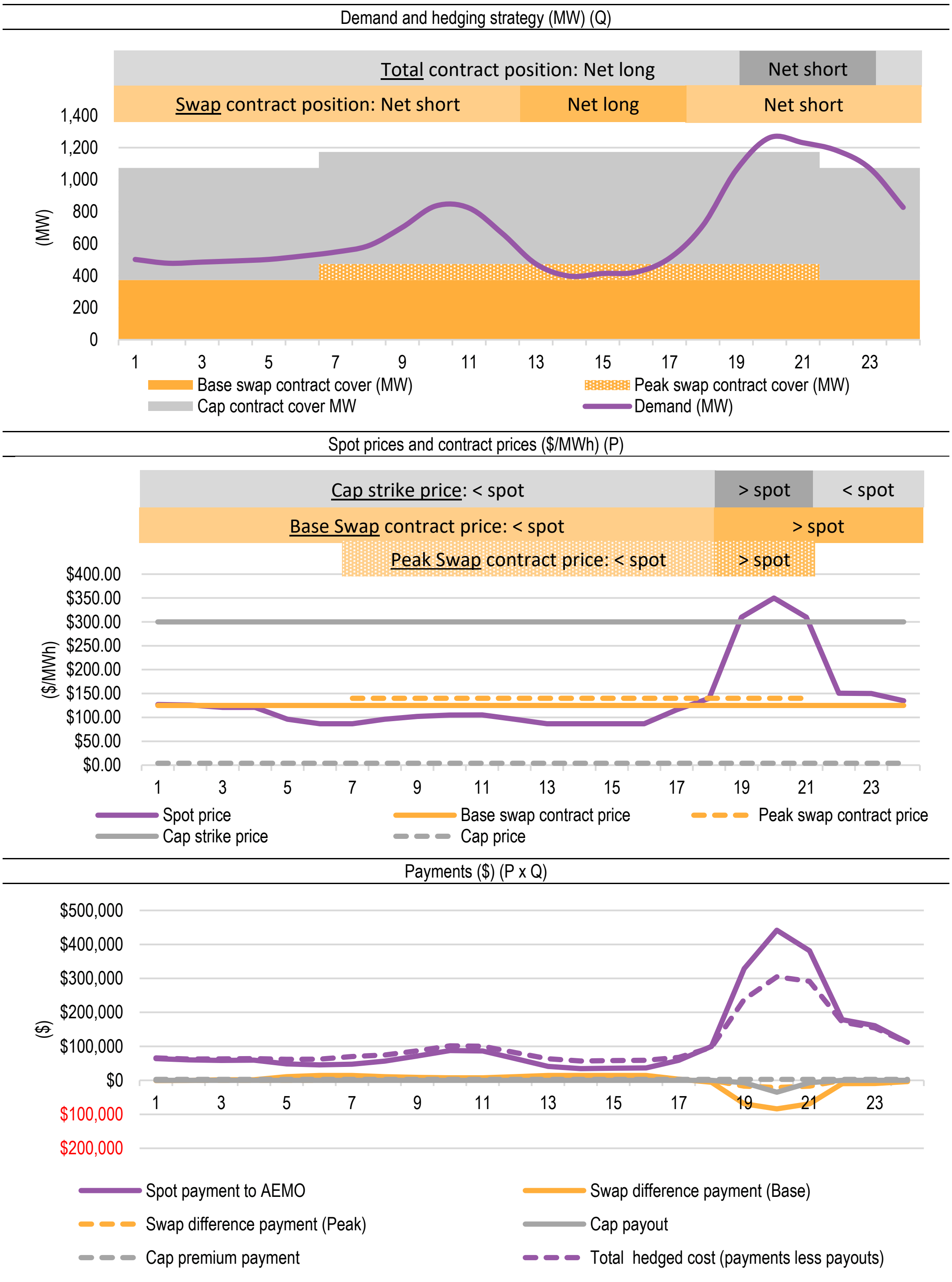
— Pays AEMO the spot price multiplied by the demand.
— Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract 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 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 and reached the conclusion that splitting the load into residential and non-residential customers does not improve accuracy 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. The matter of estimating separate WECs for residential and small business customers is explored in more detail in section 3.5 in response to stakeholder submissions to the Position Paper.

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

Region	Distribution Network	Load Type	Load Name	Source
	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
	SAPN	CLP	SACLOAD,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 about 50[1] 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 550 (i.e. 50 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 550 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

[1] 49 weather influenced simulations were used for DMO 2, whereas 50 simulations are used for DMO 3 (given the additional year of weather data).

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. ACIL Allen adopts the 95th percentile WEC from the distribution of WECs as the final estimate. In practice, 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. Choosing the 95th percentile reduces the risk of understating the true WEC, since only five per cent of WEC estimates exceed this value.

Choosing the appropriate hedging strategy

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

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

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

Demand-side settings

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

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

The key steps in developing the demand profiles are:

— The half-hourly demand profiles of the past four 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 50 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 50 years of weather data and uses a matching algorithm to produce 50 sets of weather-related demand profiles of 17,520 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead, it accepts there is a relationship and uses a matching algorithm to find the closest matching weather outcomes for a given day across the entire NEM from the past three years to represent a given day in the past.

[2] When testing the different strategies, we do not run the full set of 550 simulations as this is time prohibitive. However, we run the full set of 550 simulations once the strategy has been chosen.

- The set of 50 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 50 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 50 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 50 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 50 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

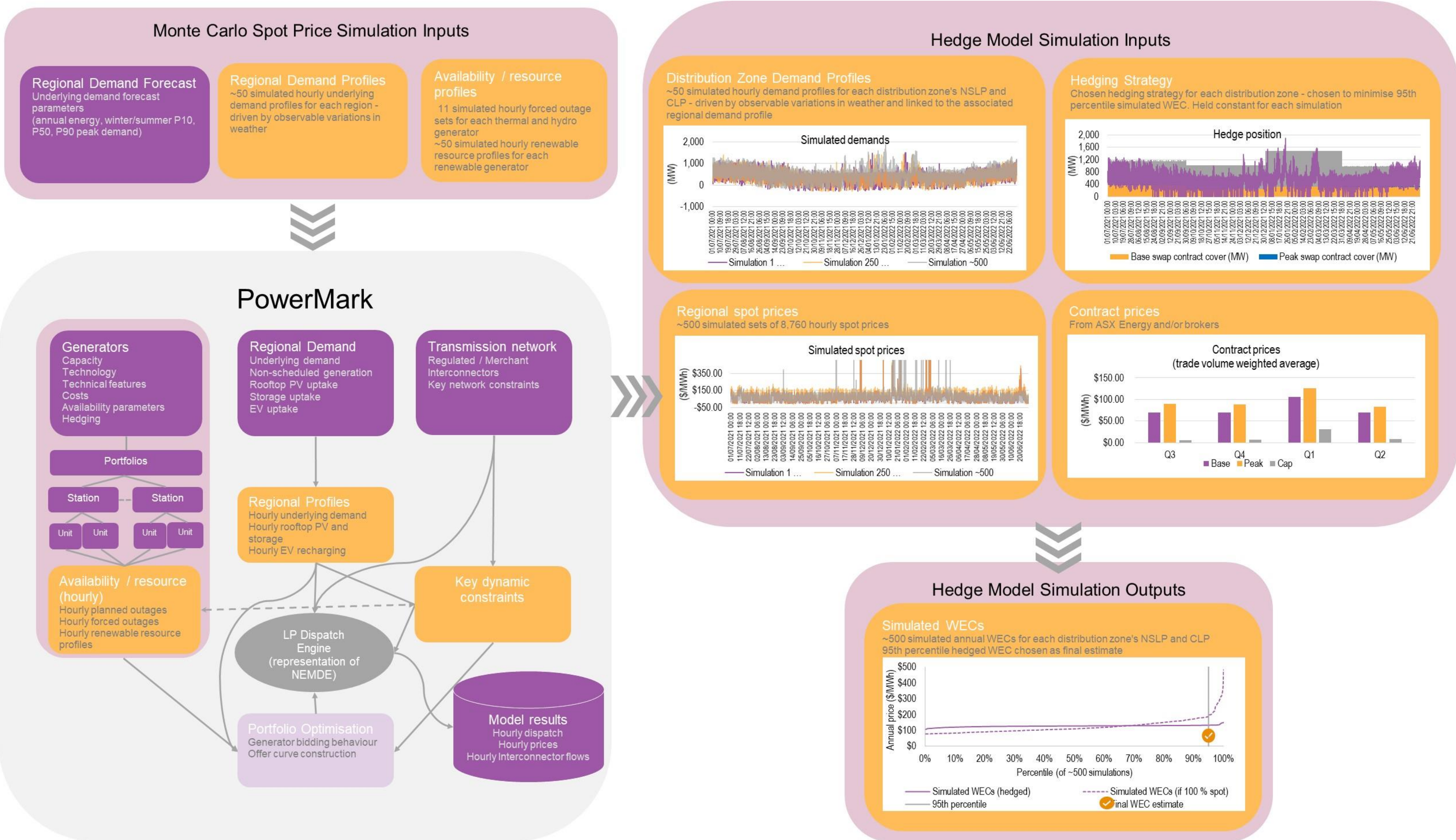
ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2021-22 we use our December 2020 Reference case projection settings which are closely aligned with AEMO’s Integrated System Plan (ISP) for the Draft Determination, and 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



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 National Transmission Planner (NTP) and the Energy Consumers Australia (ECA).

The current approach uses for estimating market fees is to make use of AEMO's budget report. For the most part, the budget report includes forecasts of fees for four or more years.

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 current 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.

As part of its methodology review and in response to submissions to the Position Paper, ACIL Allen derives these costs 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 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 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 RRO has not been triggered for 2021-22, and hence we are not required to account for the RRO in the wholesale costs of DMO 3. However, it is worth noting that this cost component should be included as part of the wholesale cost if the RRO is triggered in future determinations.

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

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 proposed 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.

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.

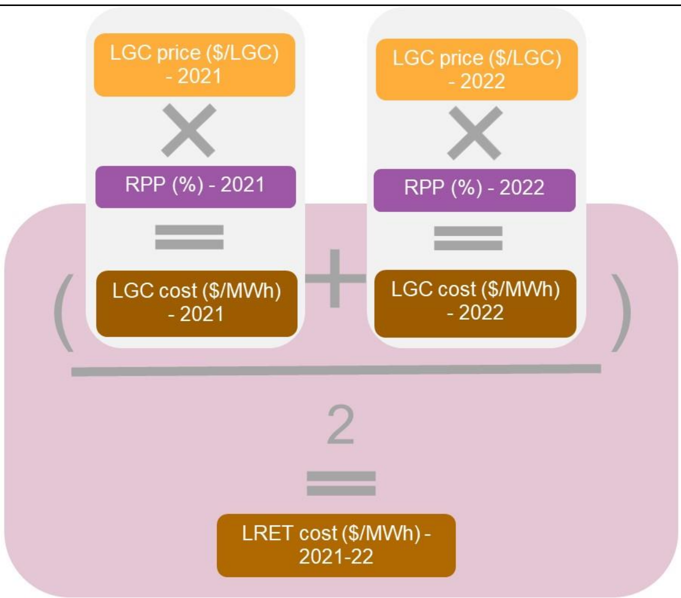
This approach involves estimating the average LGC price using LGC forward prices for the two relevant calendar compliance years in the determination period. Specifically, for each calendar compliance year, the trade-weighted average of LGC forward prices since they commenced trading is calculated.

To estimate the costs to retailers of complying with the LRET for 2021-22, ACIL Allen uses the following elements:

— The average of the trade-weighted average of LGC forward prices for 2021 and 2022 from brokers TFS
— the Renewable Power Percentages (RPPs) for 2021, to be published by the CER[3]
— estimated RPP values for 2022[4].

[3] It is worth noting that the 2021 RPP changed slightly between the 2020-21 Final Determination and the 2021-22 Draft Determination due to a slight revision in the estimated electricity acquisitions.
[4] The estimated RPP values for 2021 and 2022 are estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET targets for 2021 and 2022, respectively.

FIGURE 2.4 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.

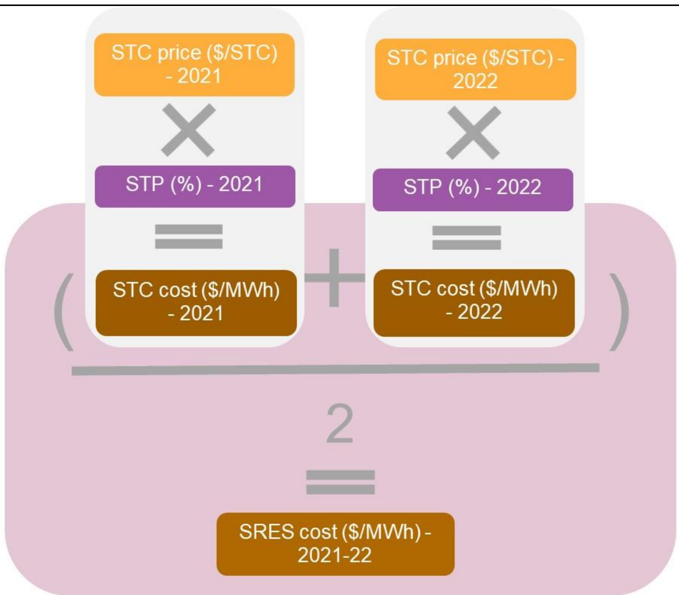
The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

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

— the binding[5] Small-scale Technology Percentages (STPs) for 2021 to be published by the CER
— estimated STP value for 2022[6]
— CER clearing house price[7] for 2021 and 2022 for Small-scale Technology Certificates (STCs) of $40/MWh.

[5] For the Draft Determination, ACIL Allen will estimate the STP using estimates of STC creations and liable acquisitions in 2021, which will take into consideration the CER's non-binding estimate. The binding STP will be published prior to, and hence used for, the Final Determination.
[6] The STP value for 2022 is estimated using estimates of STC creations and liable acquisitions in 2022, which will take into consideration the CER's non-binding estimate.
[7] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

FIGURE 2.5 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:

— Energy Savings Scheme Target for 2021 and 2022 of 8.5 per cent, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2021 and 2022 from brokers TFS.

South Australia Retailer Energy Efficiency Scheme (REES)

The Retailer Energy Efficiency Scheme (REES) is a South Australian Government energy efficiency scheme that provides incentives for South Australian households and businesses to save energy. It does this via energy efficiency and audit targets to be met by electricity and gas retailers with customers in South Australia.

The targets are set by the Essential Services Commission of South Australia (ESCOSA). REES commenced in 2009 and was set to operate until 31 December 2020.[8] However, in late 2019, a review into the scheme recommended it be extended to 31 December 2030[9], and hence it was included in DMO 2, and is included in DMO 3 for 2021-22

The cost of the REES 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.

In the AEMC's 2018 price trends methodology report, the cost of the REES was sourced using data from the relevant jurisdiction, although there is no link to the exact location of this data.[10] The

[8] https://www.escosa.sa.gov.au/ArticleDocuments/214/20190627-REES-RegulatoryFrameworkInformationSheet.pdf.aspx?Embed=Y
[9] https://www.energymining.sa.gov.au/__data/assets/pdf_file/0008/356228/2019_REES_Review_Report.pdf
[10] Table 8.5, page 49 at https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf

estimated cost was $2.50/MWh. The same cost was also report in the 2019[11] and 2020[12] price trend reports.

In the AEMC's report, the estimated cost of REES, 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 REES 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 REES 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[13], 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.

[11] https://www.aemc.gov.au/sites/default/files/2019-12/2019%20Residential%20Electricity%20Price%20Trends%20final%20report%20FINAL.pdf
[12] https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2020
[13] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

3 RESPONSES TO SUBMISSIONS TO POSITION PAPER

The AER forwarded to ACIL Allen a total of 15 submissions in response to its Position Paper. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration for the 2021-22 Draft Determination. A summary of the review is shown in Table 3.1. The following sections in this chapter address each of the relevant issues raised in the submissions.

TABLE 3.1 REVIEW OF ISSUES RAISED IN SUBMISSIONS IN RESPONSE TO DRAFT DETERMINATION

ID	Stakeholder	Wholesale energy cost	Environmental costs	Other energy costs
1	ActewAGL	Yes	Nil	Yes
2	Australian Energy Council (AEC)	Yes	Nil	Nil
3	AGL	Yes	Yes	Yes
4	Alinta Energy	Nil	Nil	Nil
5	Ausgrid	Nil	Nil	Nil
6	Energy Australia (EA)	Yes	Yes	Nil
7	Energy Consumers Australia (ECA)	Nil	Nil	Nil
8	Etrog Consulting (Etrog)	Yes	Nil	Yes
9	Meridian Energy Australia and Powershop Australia (MEA Group and Powershop)	Nil	Nil	Nil
10	Origin	Yes	Nil	Nil
11	Public Interest Advocacy Centre (PIAC)	Nil	Nil	Nil
12	ReAmped Energy	Nil	Nil	Nil
13	Red Energy and Lumo Energy	Yes	Nil	Nil
14	Simply Energy	Nil	Nil	Nil
15	Vector Ltd	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 Wholesale energy cost

In the stakeholders' submissions, there was strong agreement with ACIL Allen's overall market-based approach for estimating the WEC, including the period used to build up the trade weighted average contract prices in the hedge model and the use of the 95th percentile from the distribution of simulations as the final WEC estimate. Some stakeholders supported further consideration of estimating separate WECs for residential and small business customers.

The submissions raised issues in relation to the following sub-components of the WEC:

— Overall approach to estimate the WEC
— Assumptions used in hedge model
— Adopting the 95th percentile WEC from the distribution of simulated WECs
— Estimating separate WECs for residential and small business customers
— COVID-19 impact on wholesale costs.

The issues raised have been addressed for each of these sub-components below.

3.2 Overall approach to estimate the WEC

A number of stakeholders confirmed their support for the continuation of the overall approach adopted in DMO 2 to estimate the WEC for DMO 3, these include:

— ActewAGL
— AEC
— AGL
— Alinta
— Etrog
— MEA Group and Powershop
— Origin.

There were no submissions not in support of the overall approach to estimating the WEC.

3.3 Assumptions used in the hedge model – book build period

The current methodology calculates the cost of each contract product used in the hedge model as the trade volume weighted average since that product commenced trading on ASX Energy (or with brokers). The AER asked stakeholders whether the current approach of using contract price and trade volume data from the time of the first trade is appropriate or should a shorter period be used.

All but one of the stakeholders responding to this item are in support of the current approach and highlight the need for consistency.

In support of the current approach

AEC notes on page two of their submission that a longer book build is a prudent approach

and means retailers are not unduly penalised for managing their expected load in advance.

AGL notes on page three of their submission that

Retailers can have different wholesale risk management policies which will lead to different hedging strategies. In our view, there are advantages and disadvantages with each approach, but it is important to maintain a consistent approach from one year to another.

Alinta Energy on page two of its submission notes:

maintaining the longer book-build approach more appropriately reflects how a risk-averse retailer would behave and does not support a book build period to hedge wholesale energy exposure of 18 months.

Etrog Consulting on page 20 of its submission states:

…it could be argued that a shorter 24 month period would be more appropriate. However, market liquidity and trading patterns change over time, and on balance it is preferable to maintain stability to leave this aspect of the methodology unchanged.

MEA Group and Powershop noted that the methodology is now mature.

In support of changing the bookbuild period

ActewAGL was the only stakeholder to suggest a change in methodology and proposes a 24-month book build on the basis that about 98 per cent of trades occur within 24 months.

3.3.2 ACIL Allen response and recommendation

Given the feedback from stakeholders, ACIL Allen is of the view that no further consideration is required on this matter, and recommends no change be made to the hedge book build methodology for DMO 3 to maintain consistency in the approach.

3.4 Adopting the 95th percentile WEC from the distribution of simulated WECs

The methodology estimates the WEC for each of about 500 simulations, and takes the 95th percentile of the distribution as the final estimate. The AER asked stakeholders whether the current approach of using the 95th percentile WEC from the distribution of simulated WECs is appropriate.

The following stakeholders stated support of continuing with the current approach:

— ActewAGL

— AEC

— AGL

— Alinta

— Etrog

— Origin.

No submissions were received suggesting a change from the 95th percentile.

3.4.1 ACIL Allen response and recommendation

Given the feedback from stakeholders, ACIL Allen is of the view that no further consideration is required on this matter, and recommends no change be made in relation to choosing the 95th percentile as the final estimate of the WEC for DMO 3 to maintain consistency in the approach.

3.5 Estimating separate WECs for residential and small business customers

The current methodology estimates the WEC based on the NSLP (as well as CLPs). This means there is no differentiation in WEC between residential and small business consumers. The AER asked stakeholders what the implications are of differentiating between residential and small business load profiles to forecast wholesale costs.

In support of separate WECs

A number of stakeholders supported further consideration of estimating separate WECs, including:

— AEC

— AGL

— Energy Australia

— Origin.

The AEC on page two of its submission states

The AEC supports steps by the AER to differentiate load profiles between residential and small business customers. This approach would provide additional certainty for retailers, and ensure that any *material differences do not unreasonably disadvantage retailers who only focus on one customer segment.*

Origin on page seven of its submission states:

Origin considers it important that load data for residential and small business customers is separated. We consider that using a combined load profile does not adequately reflect the variance between maximum and average usage for residential customers. The aggregate of small business and residential profiles also creates a flatter profile than either segment individually. For these reasons we support the AER adopting separate load profiles where it has robust and representative data.

Red Energy and Lumo Energy on page five of their submission note:

We support the AER's analysis of mechanisms for differentiating between the load profile of (aggregated) small business and residential consumers as this will provide more accurate estimates of wholesales costs for each consumer segment.

In support of continuing to estimate a single WEC

Equally, a number of stakeholders support the continuation of using the NSLP to estimate a single WEC, although noting that over time as the penetration of interval meters increases this may change.

AGL on page four of its submission notes the importance of estimating a separate WEC for residential and small business customers when there is sufficient penetration of smart meters. However, AGL also notes that at present accumulation meters remain prevalent in New South Wales, Queensland, and South Australia, and as such:

the energy usage on these meters is settled on the NSLP and until there is a large penetration of smart meters, differentiating between residential and small business profiles could result in a misalignment of wholesale costs on settlement.

Etrog on page 22 of its submission states

The energy consumed by customers without interval / smart meters is based on the Net System Load Profile (NSLP) for the purposes of settlement in the NEM. This is an aggregated load profile for basic meters that does not distinguish between small business and residential customers. To the extent that the DMO is applied to customers with basic meters, the NSLP continues to represent the best reflection of the energy for which the customers' retailer is settled in the NEM.

As more interval meters are deployed, and the customers with those meters are settled in the NEM based on their actual half-hourly data, the NSLP will become less relevant.

On that basis we support the AER investigating how to segment customers to estimate load profiles that are not dependent on the NSLP, and to consult on the findings. One way to segment the customers may be on the basis of separating residential customers from small business customers, but that is by no means the only possible segmentation method. The AER should consider and consult on the potential for a range of segmentation options to be used.

3.5.2 ACIL Allen response and recommendation

AEMO provided to the AER aggregate half-hourly load data for each distribution network zone for residential and small business customers on interval meters for the period February 2017 to February 2020. AEMO informed the AER that it is not able to the separate control load from the interval meter load data set.

AEMO also provided a monthly summary of the number of customers by meter type for each distribution network zone between November 2018 and October 2020.

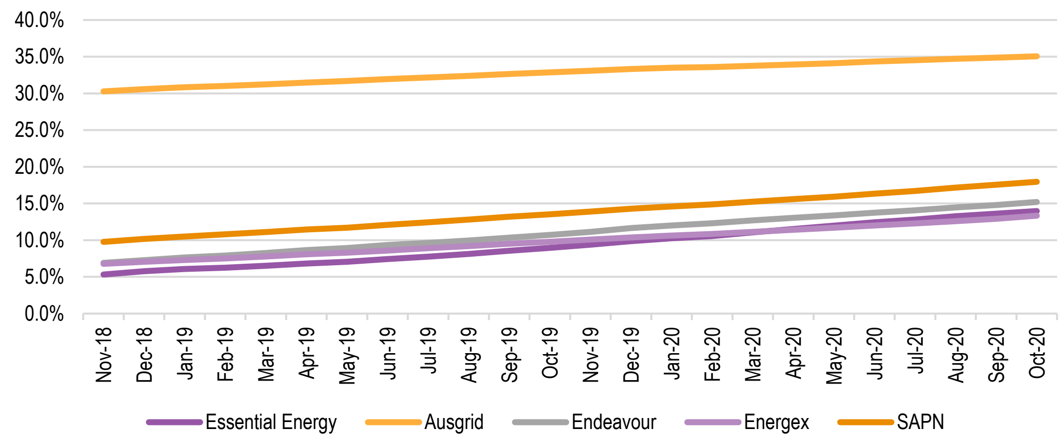
Penetration of interval meters

The graph in the top panel of Figure 3.1 shows the percentage of customers in the DMO distribution zones with interval meters is typically less than 15 per cent, except for Ausgrid for which the level of penetration is about 35 per cent. It has only been in the past 12 months that penetration levels have surpassed 10 per cent. The level of penetration has increased by about five per cent per year over the past few years.

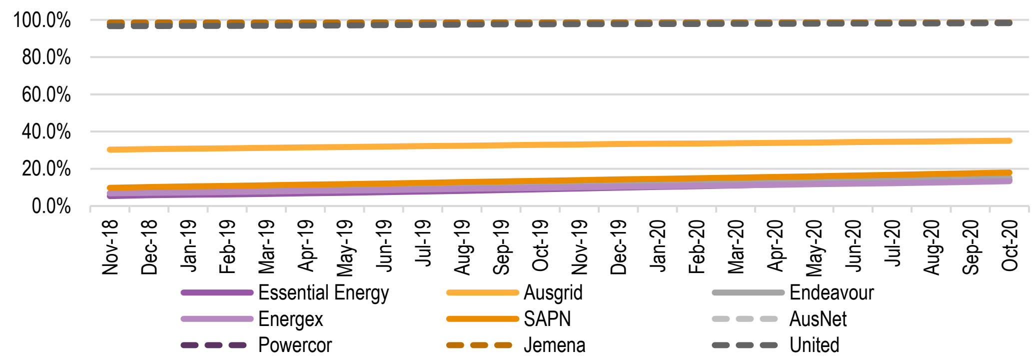
However, to put this into context, the graph in the lower panel of Figure 3.1 shows that in Victoria, about 98 per cent of customers are on interval meters.

Unfortunately, the interval penetration data is provided in aggregate within each network and not split by customer type.

FIGURE 3.1 PROPORTION OF CUSTOMERS ON INTERVAL METERS



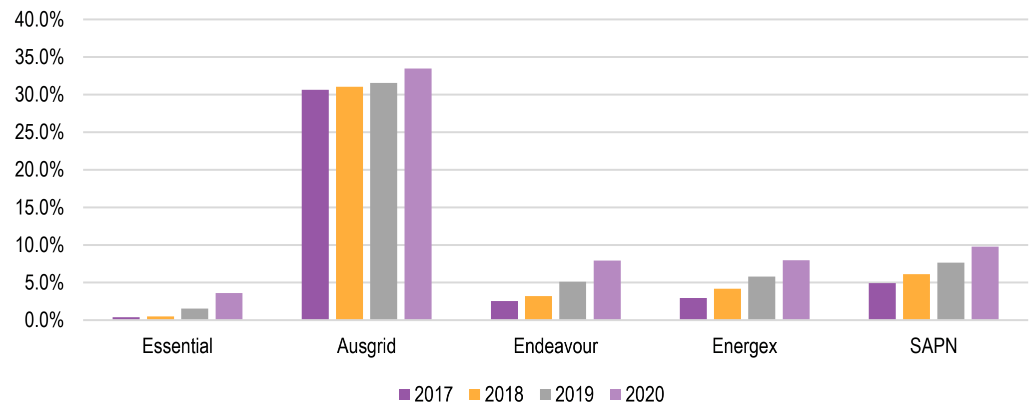
(including Victoria for comparison)



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Although about 15 per cent of residential and small business consumers are on interval meters (with exception of Ausgrid), the energy requirements of these consumers are less than 10 per cent of the total energy requirements of residential and small business consumers on interval meters or accumulation meters (as measured by the NSLP). In other words, in energy terms, 90 per cent of consumers are on the NSLP.

FIGURE 3.2 PROPORTION OF RESIDENTIAL AND SMALL BUSINESS CONSUMERS ON INTERVAL METERS BY FINANCIAL YEAR

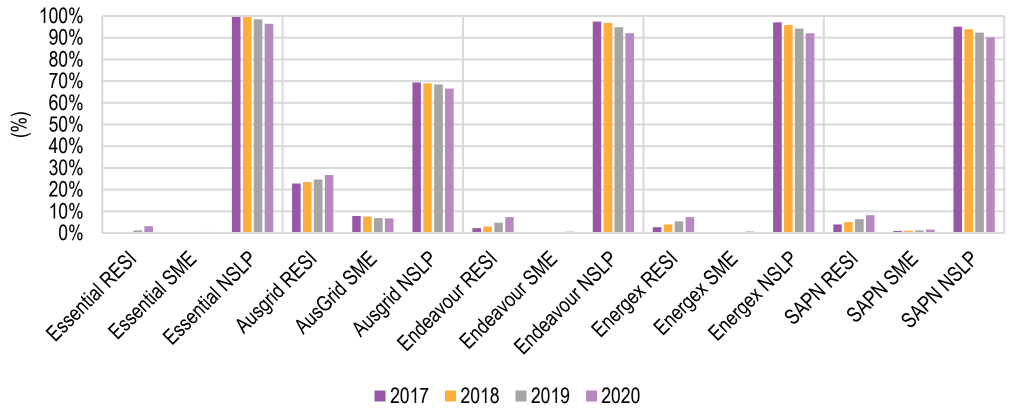


Note: The percentage is equal to the annual load of those consumers on interval meters divided by the sum of the interval meter load and the NSLP load.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Most stakeholders in support of a separate WEC relate this to the importance of accounting for different customer type mixes, and hence different load profiles, for different retailers. However, Figure 3.3 shows that based on the data provided by AEMO, the small business interval meter load represents less than one per cent of the total energy requirements within each distribution zone. Again, the exception is the Ausgrid zone, but even there, small business customers represent only about seven per cent of the total energy requirements.

FIGURE 3.3 PROPORTION OF RESIDENTIAL AND SMALL BUSINESS LOAD ON INTERVAL METERS OR NSLP BY FINANCIAL YEAR



Note: The percentage is equal to the annual load of those consumers on interval meters divided by the sum of the interval meter load and the NSLP load. RESI refers to residential consumers on interval meters; SME refer to small business consumers on interval meters.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

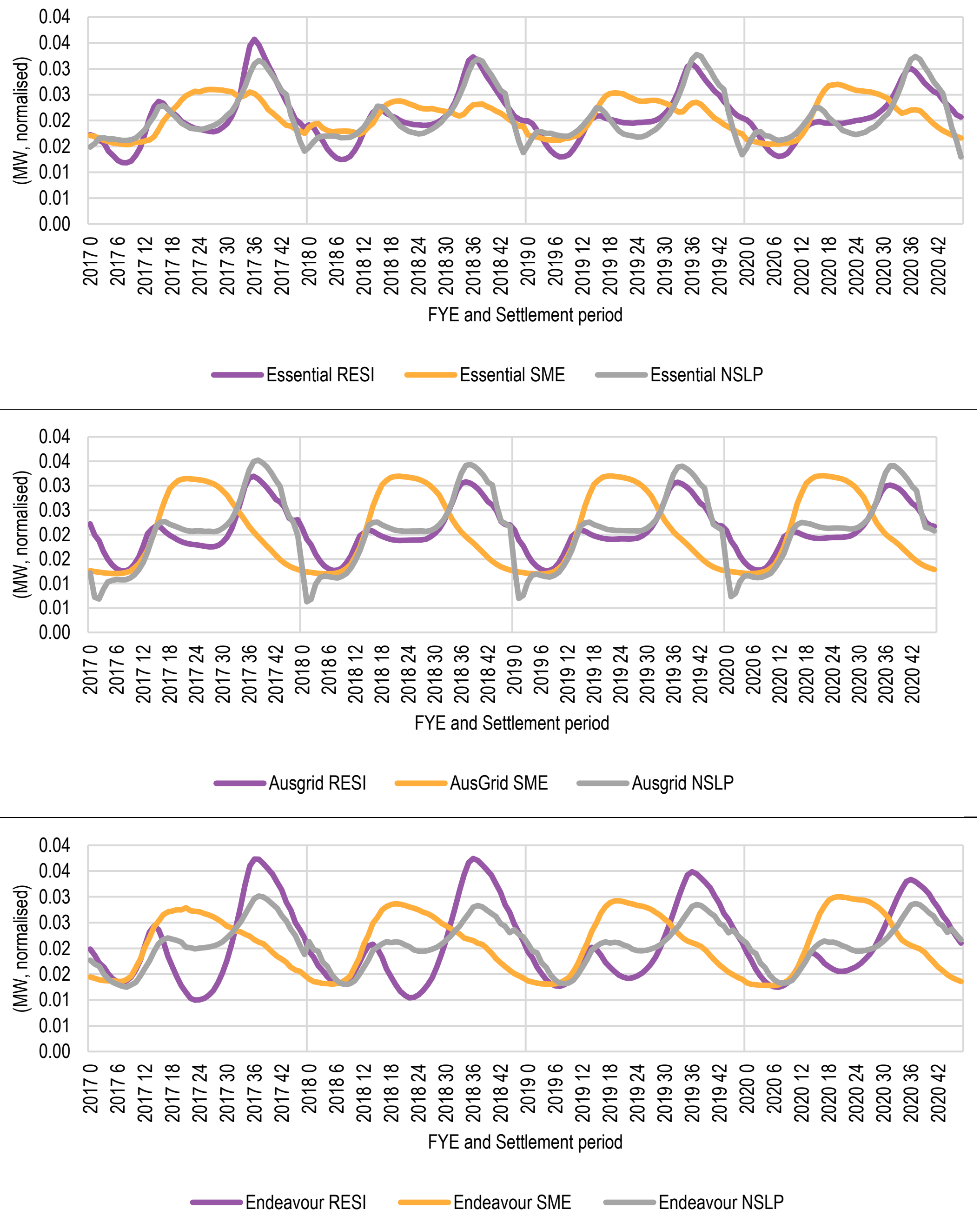
Load profiles

Figure 3.4 and Figure 3.5 show the average time of day load profile by customer type based on the interval meter data. For comparison, included in these graphs is the time of day load profile for the NSLP data (i.e. load data from accumulation meters). In these graphs the load has been normalised such that the area under the curve sums to one. This is done to remove differences in scale – as it is the shape of the load that is important when considering the WEC.

Key observations from these graphs are:

- Generally, there is a good match between the load shape of residential customers on interval meters and the NSLP
- However, there are some specific differences between the load shape of residential customers on interval meters and the NSLP worth noting:
  - It can be seen that there is a spike in load for residential customers on interval meters around midnight or 1 am for some distribution zones. This is likely to be caused by hot water systems coming online – an indication that the dataset indeed includes control load.
  - It was expected that the residential interval meter load profile would display more of a carve out during daylight hours on the basis that residential customers installing interval meters are more likely to have rooftop solar PV.
    - However, ACIL Allen confirmed with the AER that the interval meter load data excludes customers that export solar PV to the grid (but includes customers who have rooftop PV but do not export to the grid); whereas due to the way the NSLP is calculated it includes all customers on accumulation meters regardless of whether they export to the grid.
    - It is probably the case that in the Endeavour zone, residential customers on interval meters have a lower propensity to export to the grid (due to smaller PV installations) and hence the load profile displays more of a carve out during daylight hours than the corresponding NSLP.
- Not surprisingly, business customers on interval meters in aggregate have a load shape that peaks during daylight hours (which align with normal business hours).

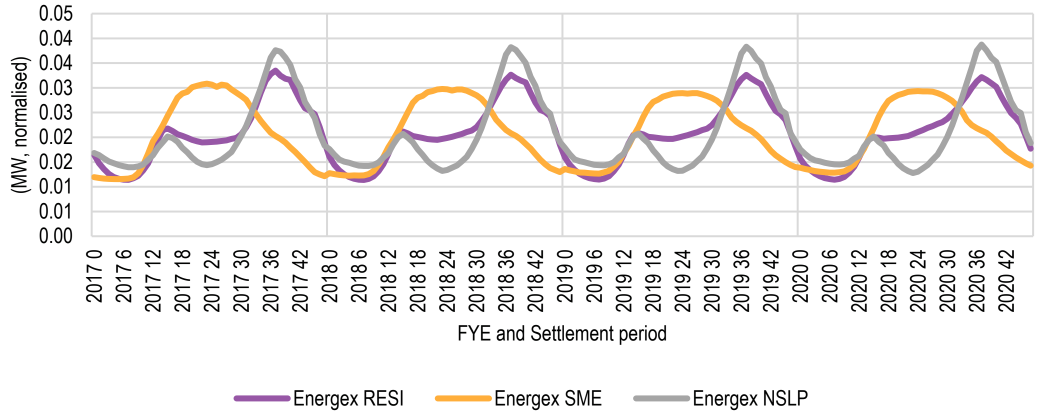
FIGURE 3.4 AVERAGE TIME OF DAY LOAD – NEW SOUTH WALES

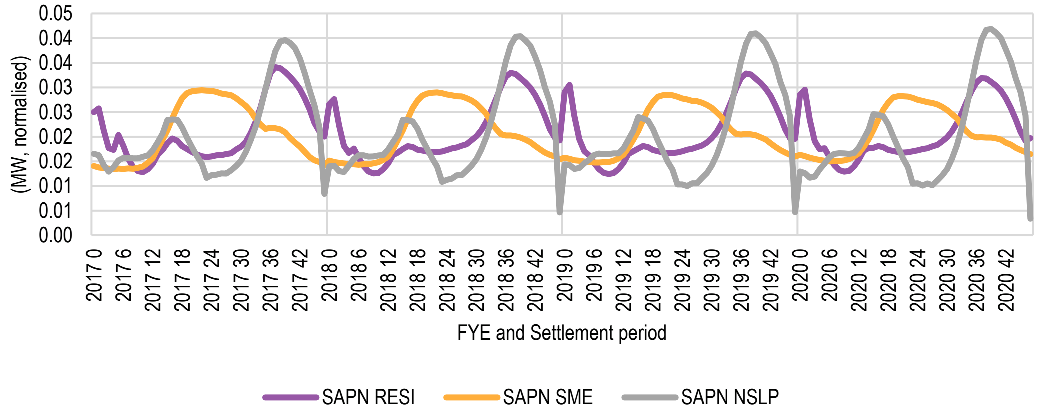


Note: RESI refers to residential consumers on interval meters; SME refer to small business consumers on interval meters.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 3.5 AVERAGE TIME OF DAY LOAD – QUEENSLAND AND SOUTH AUSTRALIA





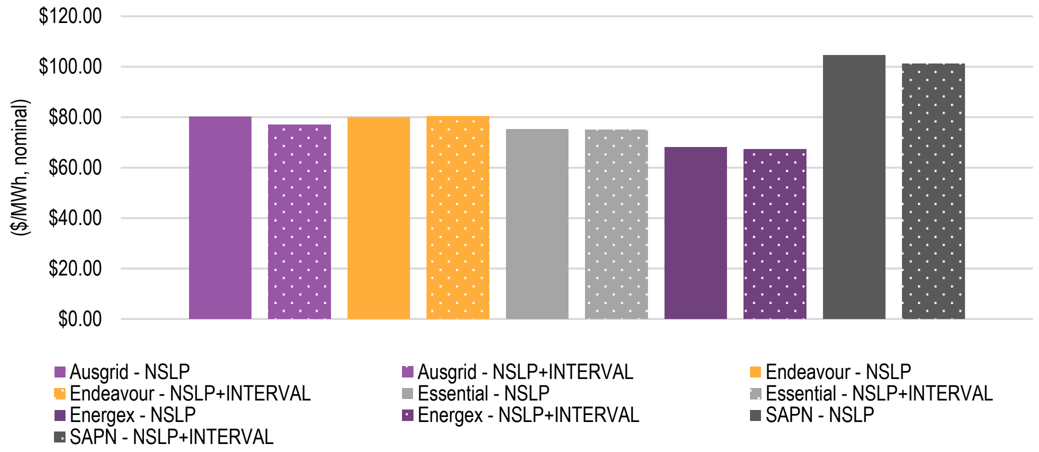
Note: RESI refers to residential consumers on interval meters; SME refer to small business consumers on interval meters.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Impact on WEC

ACIL Allen has combined the NSLP and interval meter load data and subjected this combined load profile to its standard methodology to estimate the WEC for each distribution zone (more details of the inputs into the analysis are provided in section 4.2). Figure 3.6 shows a comparison of the estimated WEC for the combined NSLP and interval meter load, and the WEC of the NSLP for 2021-22. The WEC for the combined load is about one per cent lower than the WEC of the NSLP. This is not surprising given the combined load includes the small business load which flattens out to a small extent the carve out in load during daylight hours, making the load cheaper to hedge.

FIGURE 3.6 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2021-22



SOURCE: ACIL ALLEN ANALYSIS

ACIL Allen recommendation

ACIL Allen is of the view that it is prudent to continue to estimate a single WEC based on the NSLP, rather than estimate a separate WEC for residential and small business consumers based on the provided load data, for the following reasons:

— Although some retailers have suggested that each retailer has a different mix of residential and small business customers, the fact that the small business load (based on the data provided by AEMO) represents a very small percentage of the total energy potentially subject to the DMO in our view obviates the need for separate WECs.

— The interval meter load data does not separate out control load.

— In our view, load associated with consumers on interval meters who export rooftop PV output to the grid also should be considered (or least the portion of their load drawing from the grid).

— AEMO's procedures for obtaining, measuring, and determining the NSLP load data are well established, documented and have withstood scrutiny for over a decade; whereas the procedure used to extract the interval meter data is not documented at this stage, and yet to be released into the public domain, and this in our view presents a risk that provision of this data from one year to the next may well not be consistent or accurate.

— Finally, the estimated WEC of the combined load is less than one per cent different to the WEC of the NSLP.

In addition, the more important matter remains:

— It is not possible to estimate a separate WEC for residential and small business customers on basic meters (which are the vast majority of customers subject to the DMO). It can only be inferred from the interval meter load data which runs the risk of introducing more inaccuracy in estimating the WEC, rather than increasing accuracy.

3.6 COVID-19 impact on wholesale costs

In our methodology review report to the AER for the Position Paper we stated the reasons why we though the methodology appropriately accounts for the impact of COVID-19.

AGL notes in its submission agreed that the methodology accounts for the impact of COVID-19.

3.7 LRET

Some stakeholders support the market-based approach used to estimate the cost of LRET. These include:

— Etrog
— Origin

However, AGL and Energy Australia continue to suggest that cost of LRET should be based on the long run cost to retailers rather than the market price of LGCs. These submissions suggest that the forward market for LGCs is thinly traded and is subject to price volatility.

3.7.1 Thinly traded market

AGL on page five of their submission state

AGL has consistently highlighted that basing the cost of the LRET only on LGC market prices is no longer appropriate as only a small percentage of LGCs are traded on the spot market and these prices are often not reflective of a retailers' underlying and historic cost of procuring LGC certificates.

Energy Australia in its submission to DMO 2 suggested that the number of LGCs traded in the market are a small fraction of those surrendered each year. In its latest submission, Energy Australia has recast this argument in terms of liquidity ratios – comparing the lower liquidity ratios of LGCs to those of the electricity futures market but do not conclude what this really means (aside from a reference to an AER comment about liquidity in the AER's *2020 State of the Energy Market* report). ACIL Allen fully expects liquidity ratios to be higher for electricity contracts. Electricity contracts are hedges against half-hourly electricity spot prices and demand which are volatile and change substantially by time of day and season; LGC contracts pertain to a single annual and largely known target, and a single annual price.

ACIL Allen continues to be of the view that LGCs trade reasonably well in the market. For example, LGC market trades during calendar year 2019 amounted to over 69 million LGCs, or over two times the mandated LRET target for 2019, as reported in the CER's Q4 2019 Quarterly Carbon Market Report[14].

In addition, ACIL Allen's analysis of TFS broker data shows that TFS-brokered forward contracts for calendar year 2019, since they commenced trading, comprise around 40 per cent of the LRET target for 2019. If 2019 spot trades are included, then this share increases to around 53 per cent. This indicates that the broker data used in estimating LGC prices in the DMO Determinations is robust and representative of the broader LGC market.

Compared with 2019, the number of trades in TFS-brokered forward contracts (to early January 2021) have increased by 45 per cent and 81 per cent for the 2021 and 2022 surrender years respectively. Not surprisingly, liquidity in the LGC forward market is increasing in line with the number of large-scale renewable energy projects that have been commissioned over the past few years.

3.7.2 LGC price floor

AGL suggests that the LGC forward price could be subject to a floor price to:

ensure that in instances of price volatility where LGC prices fall to unrealistic levels (compared to retailers' underlying costs), it does not unduly impact the estimation of the LRET allowance under the DMO.

AGL suggest the floor price could be set by the Australian Carbon Credit Unit (ACCU) certificate price adjusted by the NEM emissions intensity factor, and give the following example:

Using the ACCU spot price of $15.85 and an emission factor for H1 2020 of 0.7264 tCO2-e/MW hr from the Clean Energy Regulator (CER) in their Quarterly Carbon Market Report 3 would produce a cost estimate for abating carbon in the NEM of $11.50 per certificate. AGL would propose this provides a

[14] CER, Quarterly Carbon Market Report, December Quarter 2019, Figure 15 on page 20. Note, the CER is yet to update this data in subsequent reports.

reasonable floor price to LGCs in the future if the AER is not willing to explore other options for calculating the actual efficient cost of providing LGCs over the scheme life.

ACIL Allen notes, at this stage the trade volume weighted prices of LGCs in 2021 and 2022 are greater than the equivalent ACCU price. Some market analysts and participants have suggested that the price of ACCUs may act as a price floor for LGCs in the future. If there is a formal link between LGC prices and ACCUs then this will naturally become apparent in the LGC forward market over time and obviate the need to artificially apply a price floor when estimating the LGC costs from the DMO.

3.7.3 Blended approach

In their submission, Energy Australia suggest once again that an alternative approach could involve using a weighted average of the LGC costs associated with PPAs and the trade weighted average price of LGCs from the forward market.

Energy Australia summarises its submission on page 6 with the statement:

By assuming all retailers procure their entire LGC requirements from the market, and as the market price of LGCs continues to decline, retailers will be further undercompensated by the DMO.

The methodology does not assume all LGCs are procured from the market, instead the methodology uses the forward market to estimate the contemporary value of LGCs (regardless of how LGCs are actually procured). ACIL Allen maintains the view that a PPA price reflects the value of generation expected over the life of the PPA by an investor at the time of commitment when faced with a variety of uncertain futures. A PPA entered into 10 or so years ago may have had a higher expectation of the value of an LGC, whereas a PPA entered into over the past 5 years may have had an expectation of reducing value of an LGC.

A price of a PPA, just like an investment in a physical power station, represents a sunk cost once the investment has been made, and subject to the future evolution of the electricity market. Similarly, a PPA is not a regulated investment, and as such does not provide a guaranteed return, nor does it represent a guaranteed value. Hence, the value of an LGC within a PPA is determined by market conditions that actually eventuate at a given point in time – rather than at the time the investment decision was made.

In any case, a reasonable proportion of PPAs, if not the majority of those not expired, do not split out LGC prices, rather the price is a bundled price. This raises the challenge of ascribing a value to the LGC component of a PPA price.

3.7.4 ACIL Allen recommendation

ACIL Allen notes that none of these arguments regarding the estimation of the LGC price are new, although some have been recast in the latest round of submissions.

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.

On this basis, 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 3.

3.8 Ancillary services

In its methodology review report, ACIL Allen recommended calculating the costs of ancillary services on a state by state basis.

This is supported by:

— ActewAGL
— AGL
— Etrog
— Origin.

3.8.1 ACIL Allen recommendation

On this basis, ACIL Allen is of the view that the recommended change be adopted for DMO 3.

3.9 Other costs – AEMO Direction costs

AGL on page three of its submission states that:

There have been several AEMO directions in recent financial years at considerable costs to consumers. There is the potential for these events to become increasingly frequent, especially in South Australia, with AEMO continuing to issue directions to maintain system security in the region. The AER should consider the impact of AEMO directions in its determination of DMO prices on a jurisdictional basis with the recovery of the costs allocated on an energy basis.

3.9.1 ACIL Allen response and recommendation

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[15].

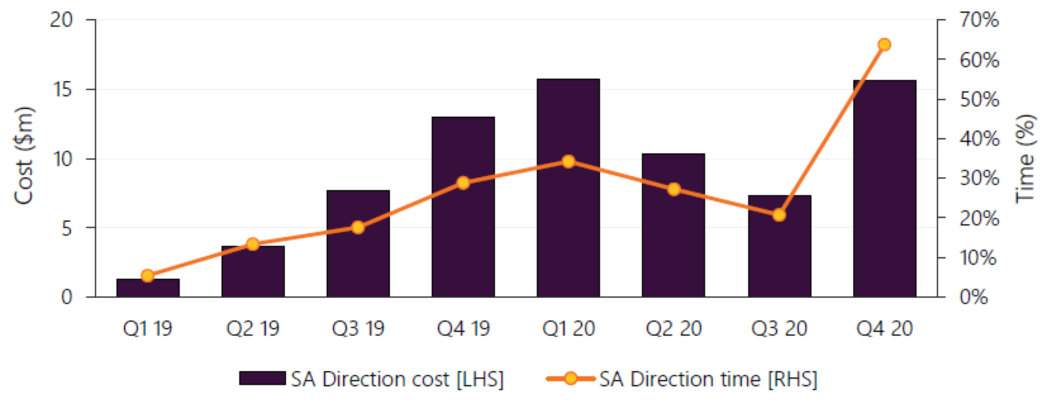
In recent times, AEMO has directed selected gas fired generators in South Australia to maintain a certain level of generation to ensure the security of the power system in maintained – this is classified as an energy direction and hence its associated compensation is recovered from customers.

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 (an example is shown in Figure 3.7). There have been energy directions over the past 24 months in South Australia (there have been no direction costs in New South Wales or Queensland over the past 24 months).

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

FIGURE 3.7 AEMO DIRECTION COSTS – SOUTH AUSTRALIA



SOURCE: AEMO QUARTERLY ENERGY DYNAMICS Q4 2020 REPORT

ACIL Allen notes that the Essential Services Commission (ESC) in its draft determination of the 2021 Victorian Default Offer (VDO) excluded the costs of AEMO directions, stating on page 32 of its draft determination report that

Without further detail about how retailers have been directly impacted by this direction we do not propose to allow for this cost in our draft decision but are investigating the matter further with AEMO.

The ESC in its final determination for the 2021 VDO also excluded the costs.

Based on our review of the AEMO documentation it appears that the AEMO Direction costs are not covered by AEMO's NEM fees (given the NEM fees are not differentiated by region), and the AER has confirmed this is the case with AEMO.

That said, AEMO Direction costs were not included in DMO 2 as there was limited transparent information available at the time the determination was made, and none of the stakeholder submissions raised the costs for consideration in response to the DMO 2 Methodology Paper or the DMO 2 Draft Determination.

ACIL Allen's view is that although AEMO Direction costs represent a real cost incurred by retailers, the cost is likely to diminish in 2021-22 in South Australia compared with 2020-21 due to the four synchronous condensers currently being installed by ElectraNet at the Davenport and Robertstown substations. According to an ElectraNet update in December 2020[16], the two synchronous condensers at Davenport are expected to be ready for operation by mid-March 2021. Site works for the additional two synchronous condensers at the Robertstown substation have commenced. These additional two synchronous condensers are expected to be ready for operation in May 2021. In other words, the four projects will be operating prior to the 2021-22 determination period.

Given ElectraNet's expectation that the synchronous condensers will avoid direction costs in 2021-22 and the fact that the DMO is an indexed based price cap, ACIL Allen is of the view that Direction costs need not be considered for DMO 3.

[16] https://www.electranet.com.au/what-we-do/projects/power-system-strength/

4

ESTIMATION OF ENERGY COSTS

4.1 Introduction

In this chapter we apply the methodology described in Chapter 2, together with the recommended changes to the methodology based on stakeholder submissions to the Position Paper (as described in Chapter 3) and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the NSLPs and CLPs for 2021-22.

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 nine 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 is 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.

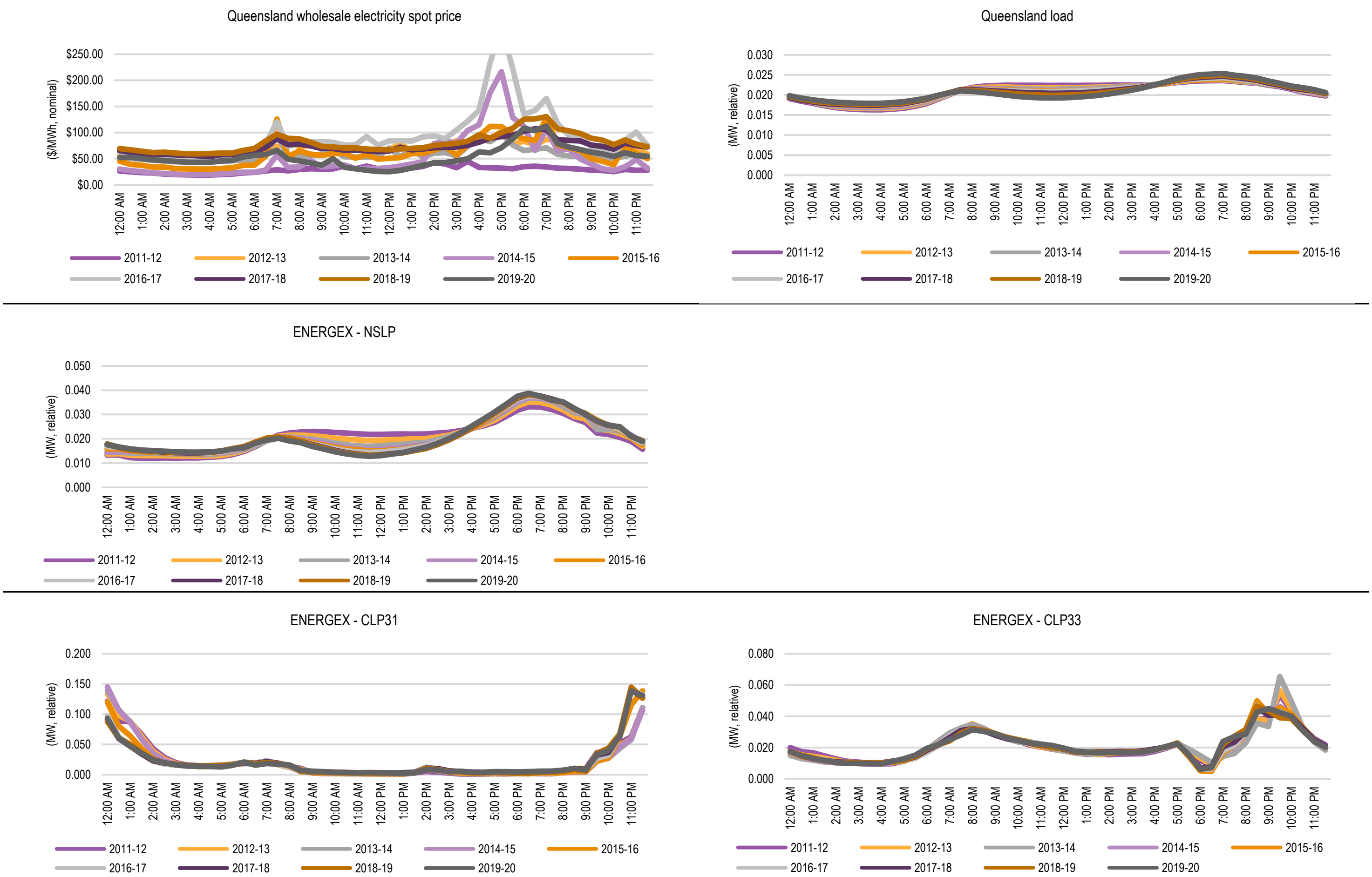
Compared with 2018-19, wholesale spot prices in 2019-20 have decreased by about $27/MWh in Queensland, decreased by about $17/MWh in New South Wales, and decreased by about $45/MWh in South Australia.

Over the past few years, the Queensland and 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[17] (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP). Although the increased penetration of rooftop PV is placing some downward pressure wholesale spot prices during daylight hours, price volatility during the evening peak has persisted. The carving out of

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

the NSLP 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.

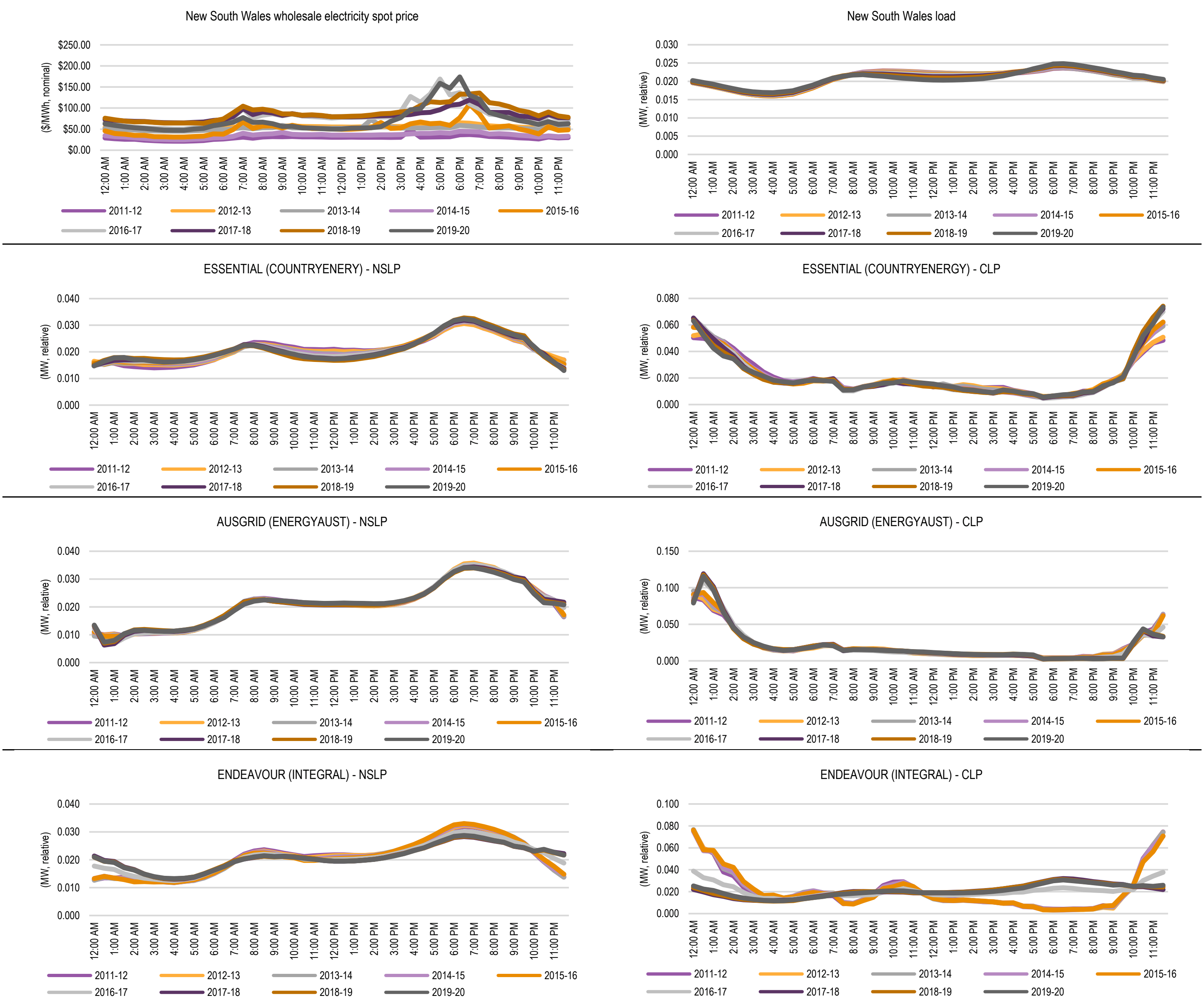
FIGURE 4.1 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – QUEENSLAND – 2011-12 TO 2019-20



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.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

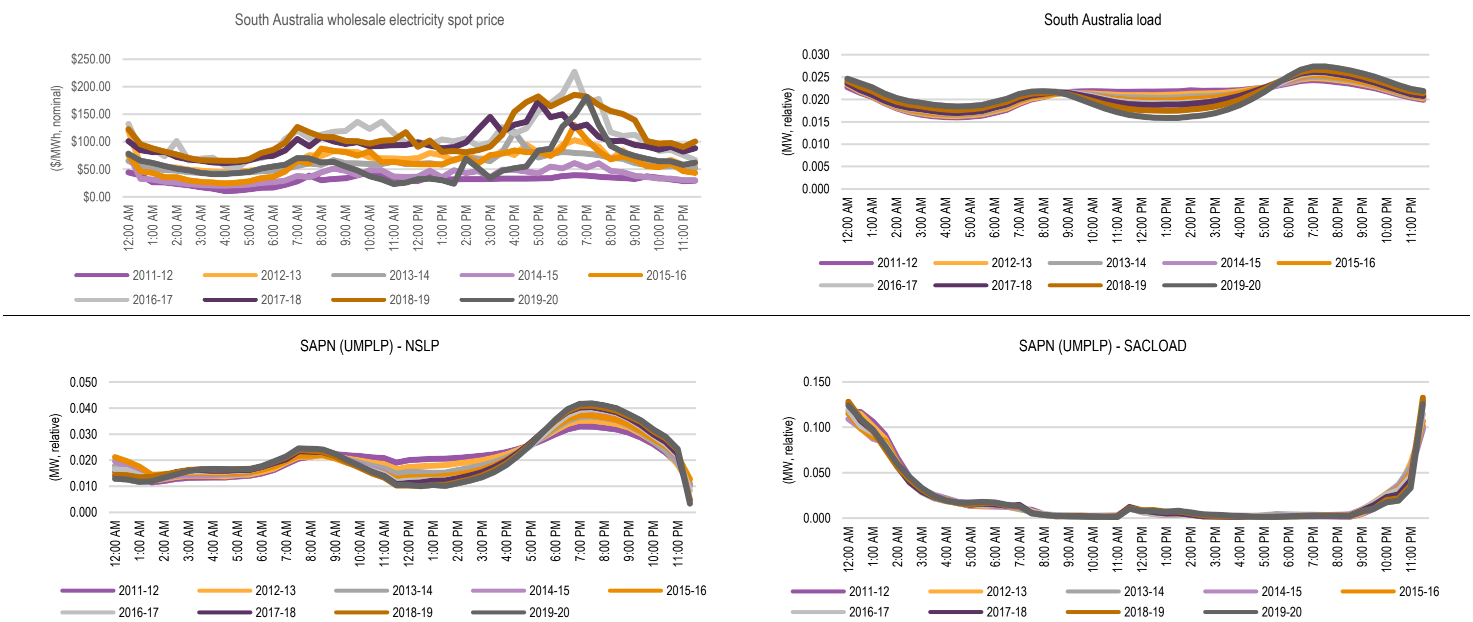
FIGURE 4.2 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – NEW SOUTH WALES – 2011-12 TO 2019-20



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.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 4.3 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – SOUTH AUSTRALIA – 2011-12 TO 2019-20



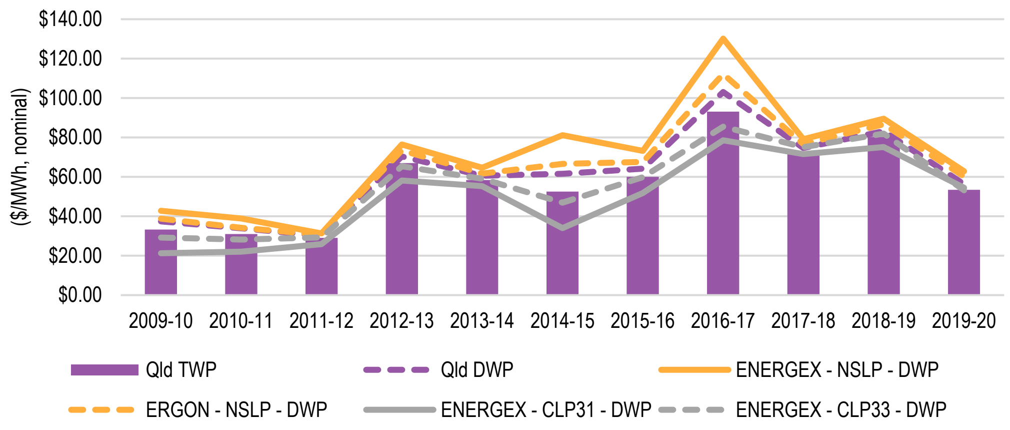
Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of the load profile, not its absolute size, which determines its wholesale energy cost.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Figure 4.4 to Figure 4.6 show the actual annual demand weighted spot price (DWP) for each of the profiles compared with the regional time weighted average spot price (TWP) over the past 11 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 four of the past 11 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 three years has resulted in it having a DWP about equal to the DWP of the corresponding Endeavour NSLP.

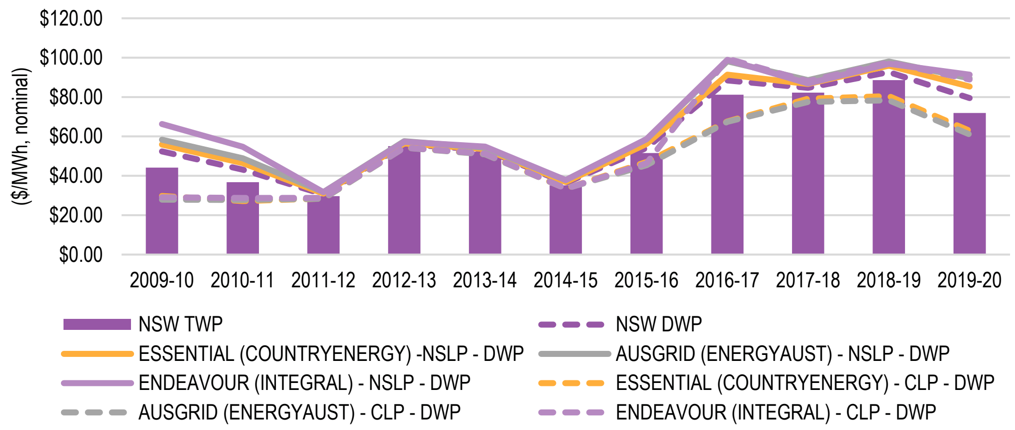
FIGURE 4.4 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY PROFILE AND QUEENSLAND TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2019-20



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

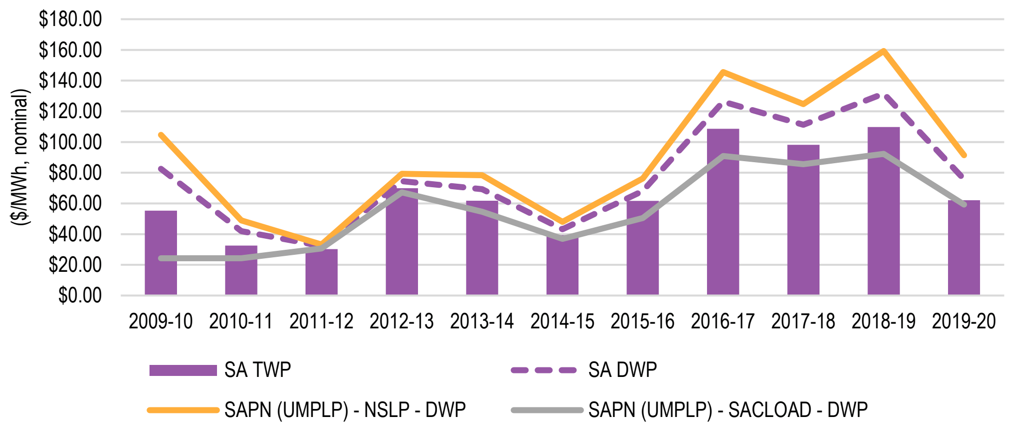
FIGURE 4.5 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY PROFILE AND NEW SOUTH WALES TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2019-20



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 2019-20



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

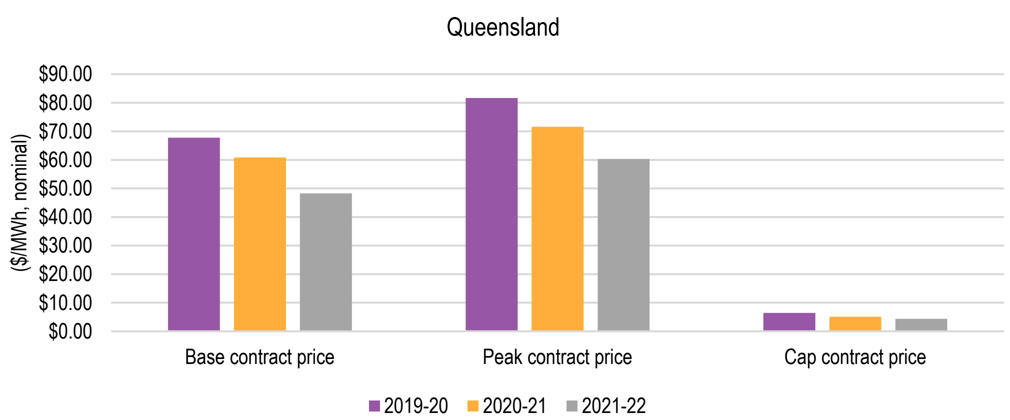
The volatility of spot prices (timing and incidence) provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) used in the methodology does not change from 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.

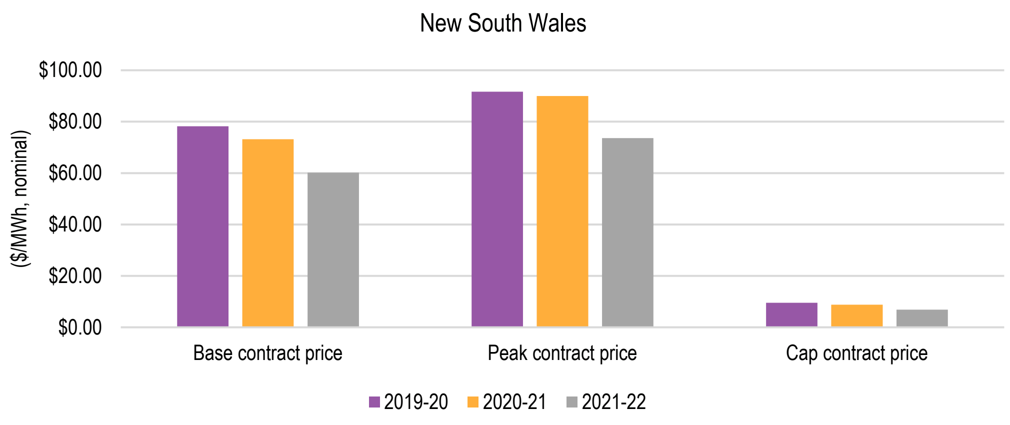
Compared with 2020-21, futures base contract prices for 2021-22, on an annualised and trade weighted basis to date, have:

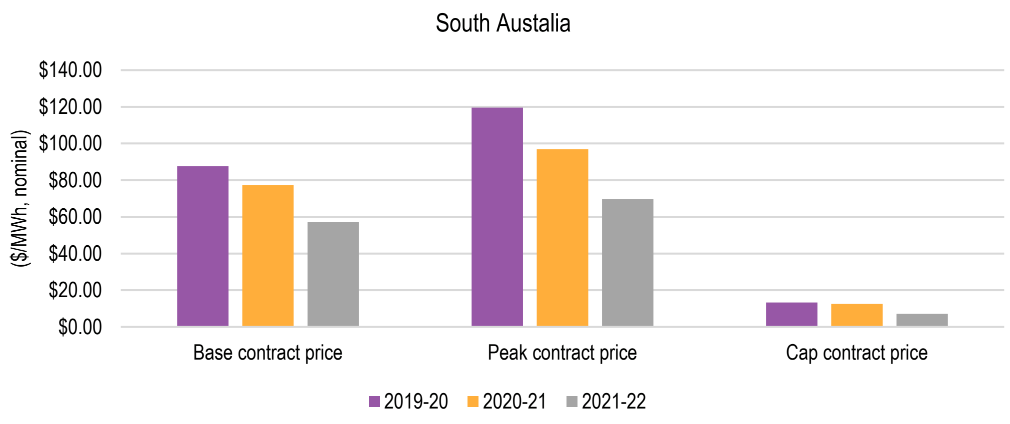
— decreased by about $12.60/MWh for Queensland
— decreased by about $13.00/MWh for New South Wales
— decreased by about $20.30/MWh for South Australia.

The market is clearly expecting further softening in price outcomes (in addition to what has occurred in 2020 to date) due to the continued strong increase in renewable investment coming on-line between 2019-20 and 2021-22. About 4,000 MW of renewable investment will enter the NEM over the next 12-18 months.

FIGURE 4.7 BASE, PEAK AND CAP CONTRACT PRICES ($/MWH, NOMINAL) – 2019-20 AND 2021-22







Note: Cap prices for 2021-22 have been inferred by the percentage change in July-September 2021 contract prices.

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 5 January 2021 inclusive. These were supplemented with broker data in the case of peak contracts. We note there was high agreement between the ASX Energy prices and the broker data – with the difference in prices from the two sources typically less than 0.5 per cent.

BOX 4.1 AVAILABILITY OF CAP CONTRACT PRODUCTS

At this stage cap contracts have not traded beyond the July-September 2021 quarter due to the delayed commencement of five-minute settlement (5MS). ACIL Allen raised this matter in its methodology review for the Position Paper.

On 5 February 2021, ASX announced that it expects to list the Australian Base Load Electricity 5 Minute Cap Futures Contract from mid to late March 2021, subject to receiving final regulatory approval. ACIL Allen will investigate using this data, if available, for the Final Determination.

We also noted in our methodology review that if it was apparent that trade volumes of other contract products had changed because of 5MS then this ought to be taken into account. To date the volume of base contracts traded has converged to the volume traded for DMO 2. This suggests that at this stage there appears to be no further reliance on base contracts as a replacement for cap contracts.

ACIL Allen consulted with TFS regarding other contract products that might be used in response to 5MS. The only other product of note is the super peak contract – but TFS indicated that there has been negligible trade in this product to date.

For the Draft Determination, ACIL Allen has calculated the cap prices beyond the July-September 2021 quarter as a function of the percentage movement in the July-September cap contracts between 2020-21 and 2021-22. We note that a similar approach has been used by the ESC when determining the 2021 VDO.

Table 4.1 shows the estimated quarterly swap and cap contract prices for 2020-21 and 2021-22.

TABLE 4.1 ESTIMATED CONTRACT PRICES ($/MWH, NOMINAL) - QUEENSLAND

	Q3	Q4	Q1	Q2
		2020-21		
Base	$59.27	$61.18	$74.61	$53.54
Peak	$68.15	$68.71	$91.43	$60.89
Cap	$2.27	$3.70	$12.40	$2.65
		2021-22		
Base	$42.69	$44.25	$63.32	$43.13
Peak	$55.38	$55.21	$81.50	$49.62
Cap	$1.90	$3.10	$10.38	$2.22
		Percentage change from 2020-21 to 2021-22		
Base	-28%	-28%	-15%	-19%
Peak	-19%	-20%	-11%	-19%
Cap	-16%	-16%	-16%	-16%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY AND TFS DATA UP TO 5 JANUARY 2021 FOR 2021-22

TABLE 4.2 ESTIMATED CONTRACT PRICES ($/MWH, NOMINAL) – NEW SOUTH WALES

	Q3	Q4	Q1	Q2
		2020-21		
Base	$71.55	$71.80	$85.57	$63.89
Peak	$80.07	$83.02	$117.52	$79.85
Cap	$4.40	$7.29	$19.47	$4.12

	Q3	Q4	Q1	Q2
		2021-22		
Base	$55.06	$55.17	$76.63	$54.10
Peak	$65.62	$64.72	$107.50	$57.00
Cap	$3.43	$5.69	$15.18	$3.22
		Percentage change from 2020-21 to 2021-22		
Base	-23%	-23%	-10%	-15%
Peak	-18%	-22%	-9%	-29%
Cap	-22%	-22%	-22%	-22%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY AND TFS DATA UP TO 5 JANUARY 2021 FOR 2021-22

TABLE 4.3 ESTIMATED CONTRACT PRICES ($/MWH, NOMINAL) –SOUTH AUSTRALIA

	Q3	Q4	Q1	Q2
		2020-21		
Base	$68.85	$69.73	$103.50	$68.05
Peak	$90.00	$89.00	$125.75	$83.40
Cap	$5.08	$7.21	$30.59	$7.70
		2021-22		
Base	$55.51	$54.31	$75.24	$43.47
Peak	$56.00	$61.00	$108.50	$53.50
Cap	$2.90	$4.12	$17.48	$4.40
		Percentage change from 2020-21 to 2021-22		
Base	-19%	-22%	-27%	-36%
Peak	-38%	-31%	-14%	-36%
Cap	-43%	-43%	-43%	-43%

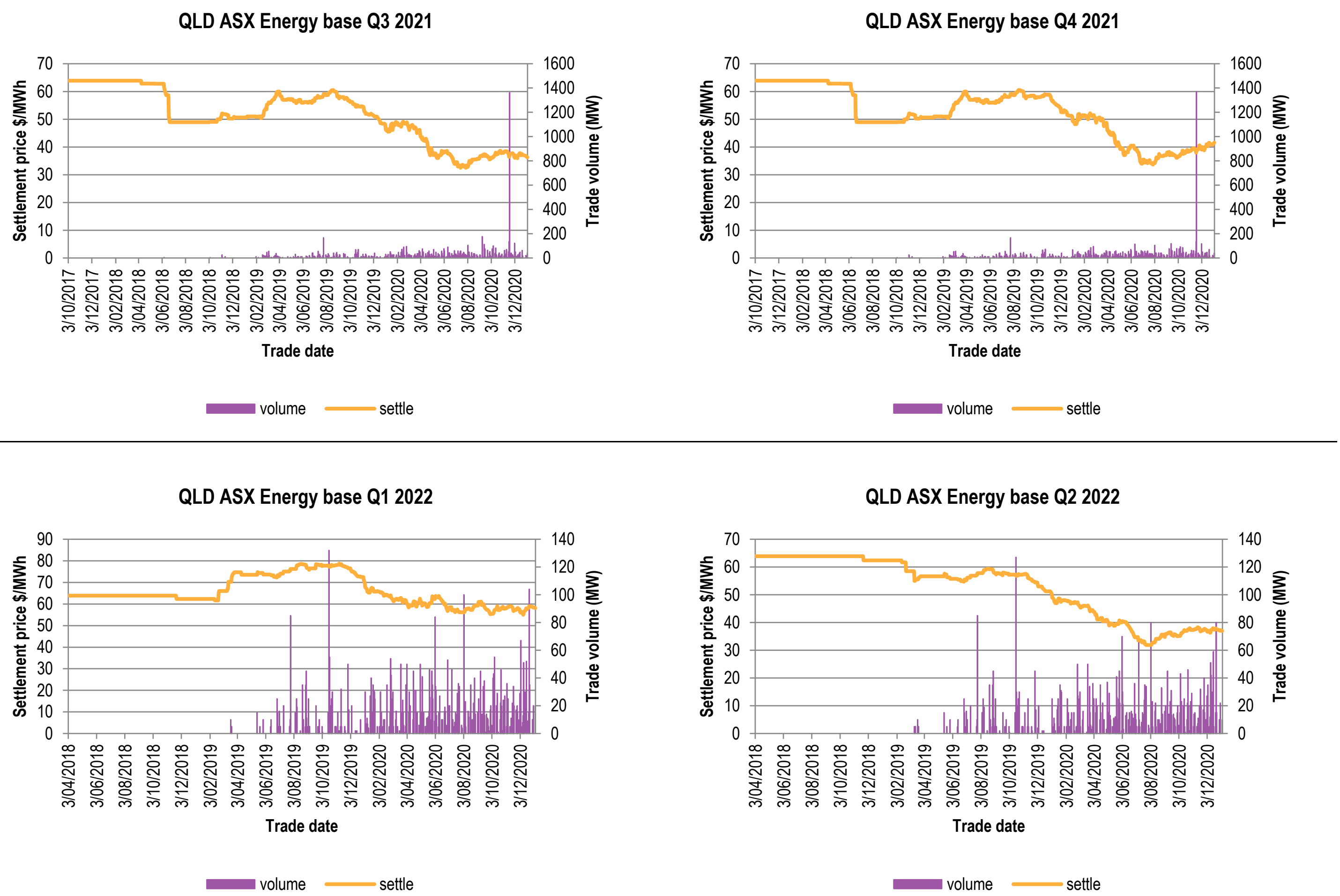
SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY AND TFS DATA UP TO 5 JANUARY 2021 FOR 2021-22

Contract prices decrease from 2020-21 to 2021-22 for all products and quarters in all regions.

In addition to the increase in renewable energy capacity, another driver of lower contract prices in 2021-22 is the continuation of lower of gas prices for gas fired generation. Spot prices across the east coast gas market have maintained their lower levels over the past 12 months. As mentioned in our report for the Final Determination of DMO 2, this has been courtesy of a range of factors including reduced gas fired generation demand, improved supply performance from CSG fields in Queensland, and reduced international LNG export prices. A key consequence of reduced international LNG export prices is that the attractiveness of selling gas on the LNG spot market has appeared to have lessened. With surplus global LNG supply expected to keep international LNG prices lower over the next 12-18 months (excluding the peak of the northern hemisphere winter).

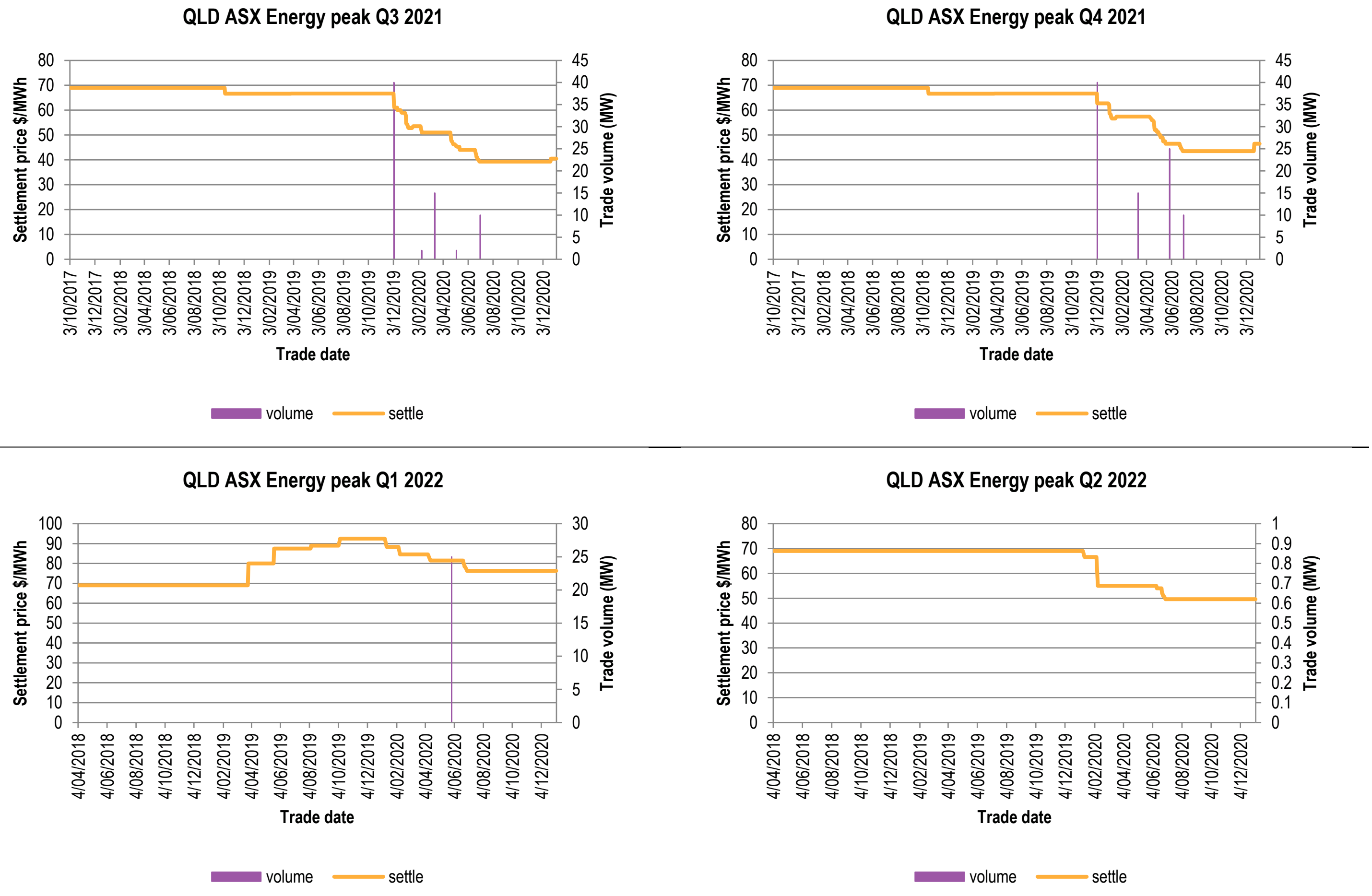
The following charts show daily settlement prices and trade volumes for 2021-22 ASX Energy quarterly base futures, peak futures and cap contracts up to 5 January 2021. It can be seen that the trading of these contracts tends to commence from mid to late 2018.

FIGURE 4.8 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES - QUEENSLAND



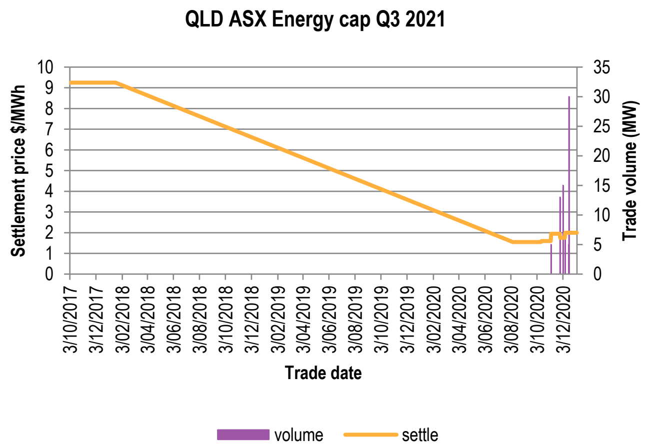
SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

FIGURE 4.9 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY PEAK FUTURES - QUEENSLAND



SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

FIGURE 4.10 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS - QUEENSLAND



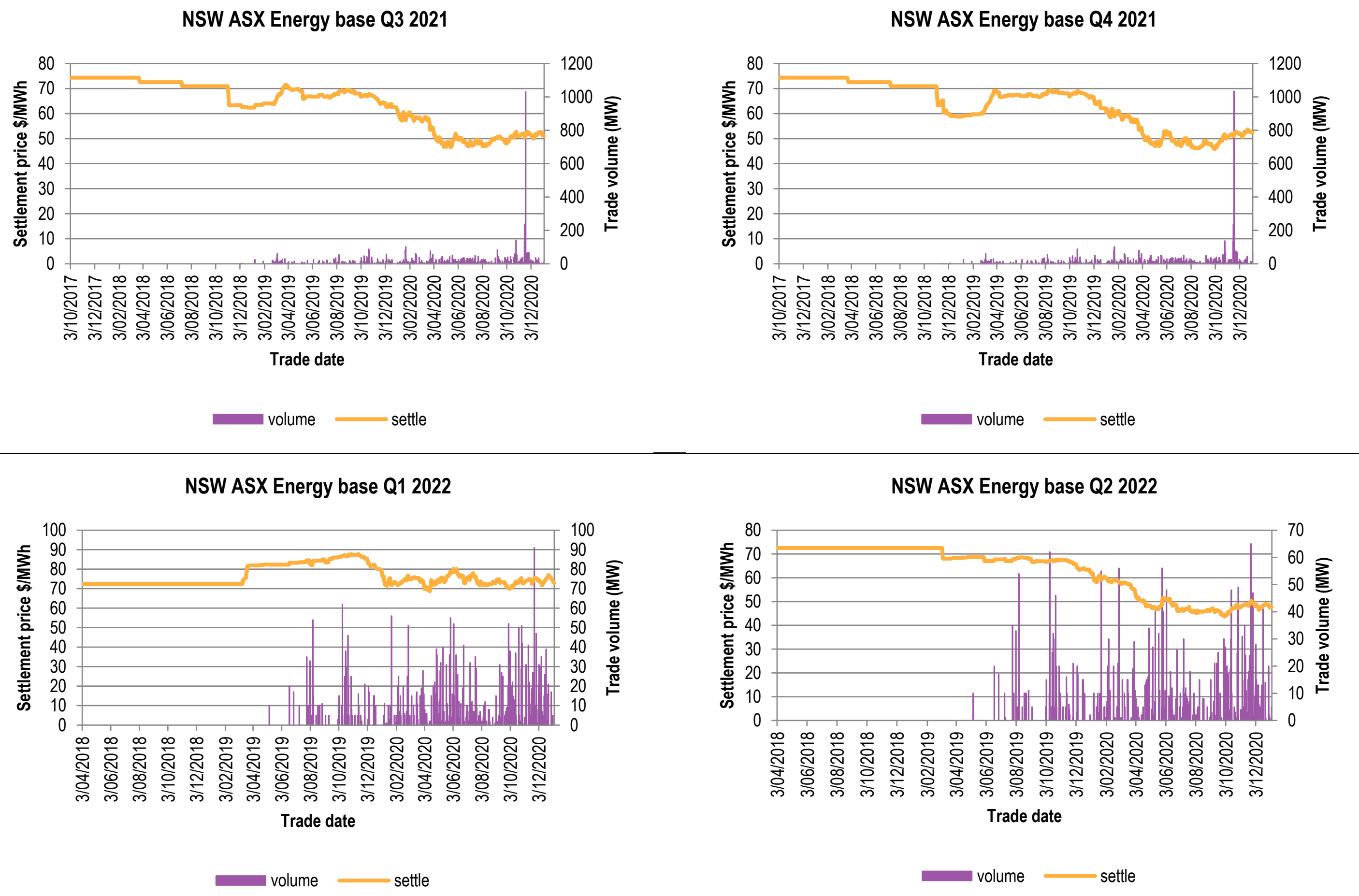
No data for Q4 2021

No data for Q1 2022

No Data for Q2 2022

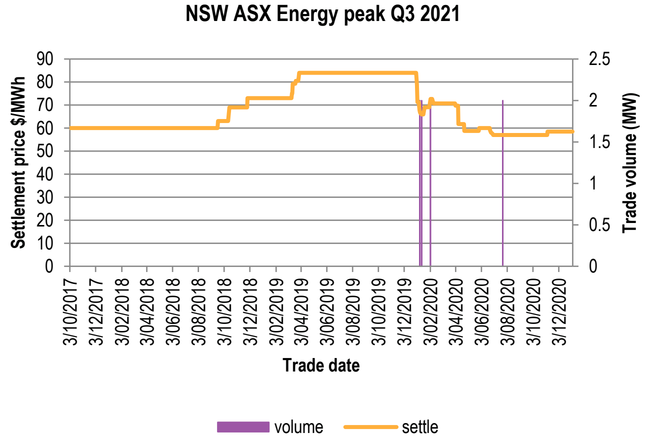
SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

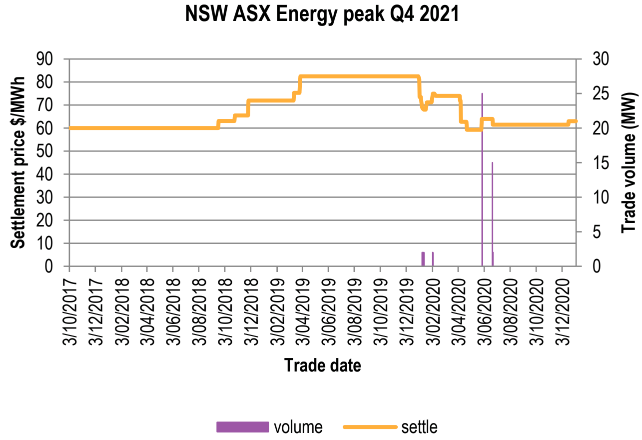
FIGURE 4.11 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES – NEW SOUTH WALES

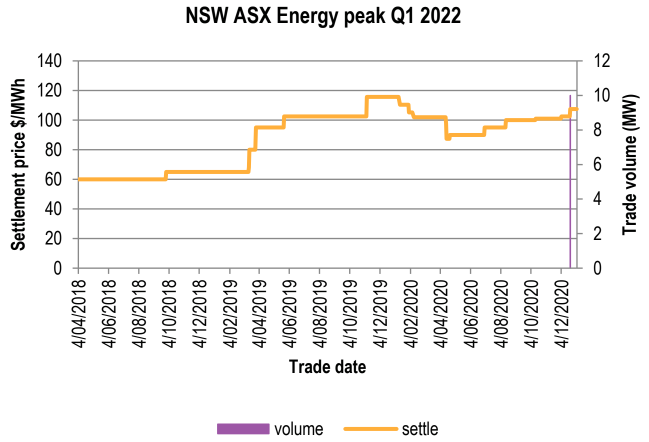


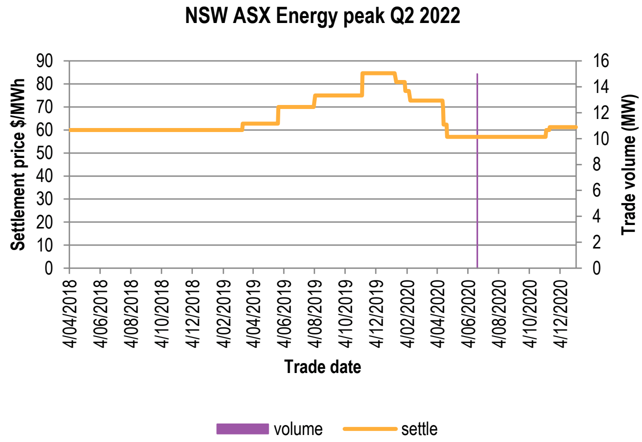
SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

FIGURE 4.12 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY PEAK FUTURES – NEW SOUTH WALES



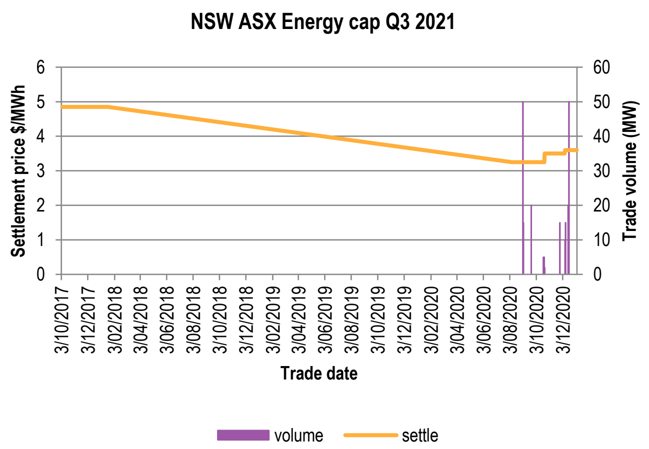






SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

FIGURE 4.13 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS – NEW SOUTH WALES



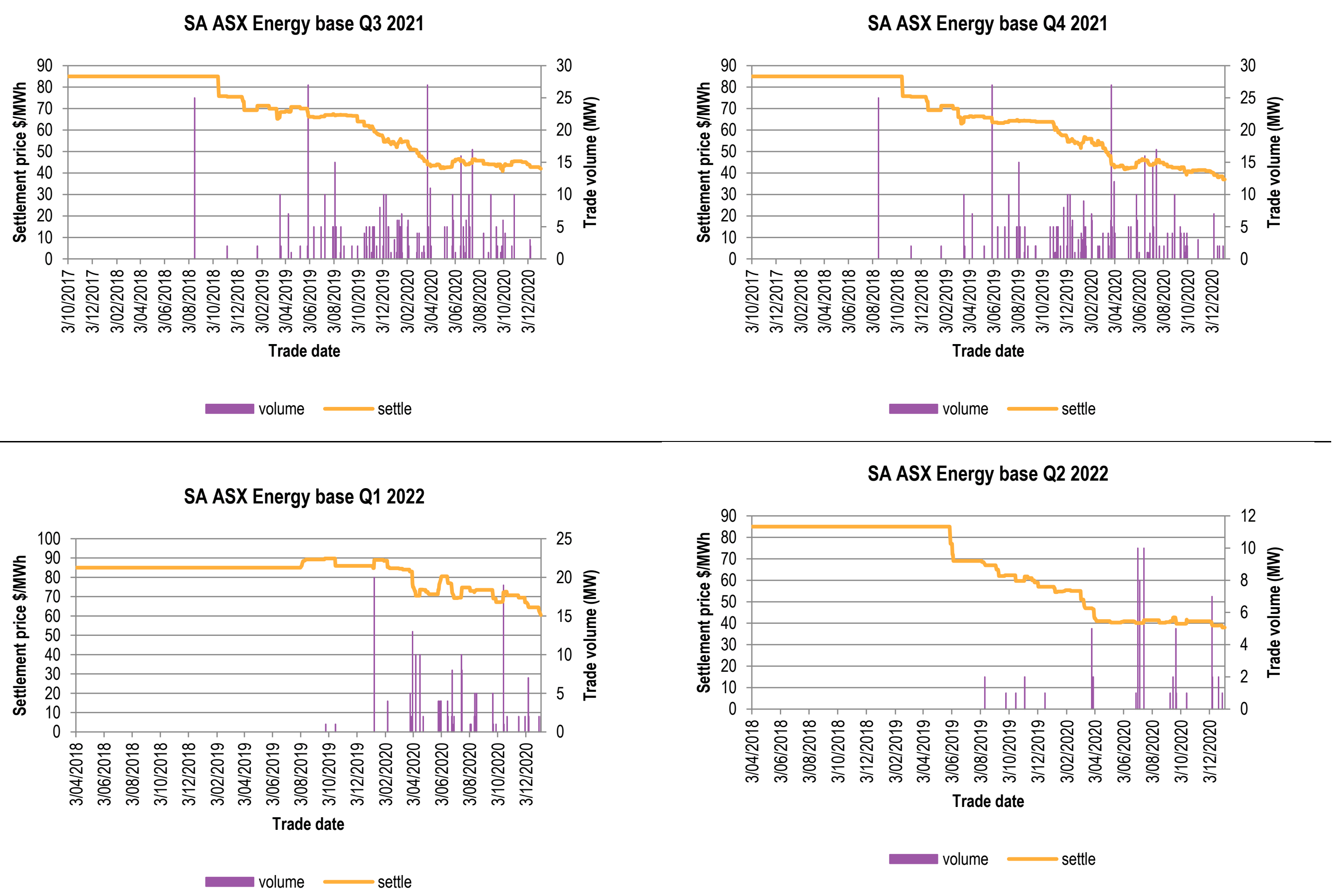
No data for Q4 2021

No data for Q1 2022

No data for Q2 2022

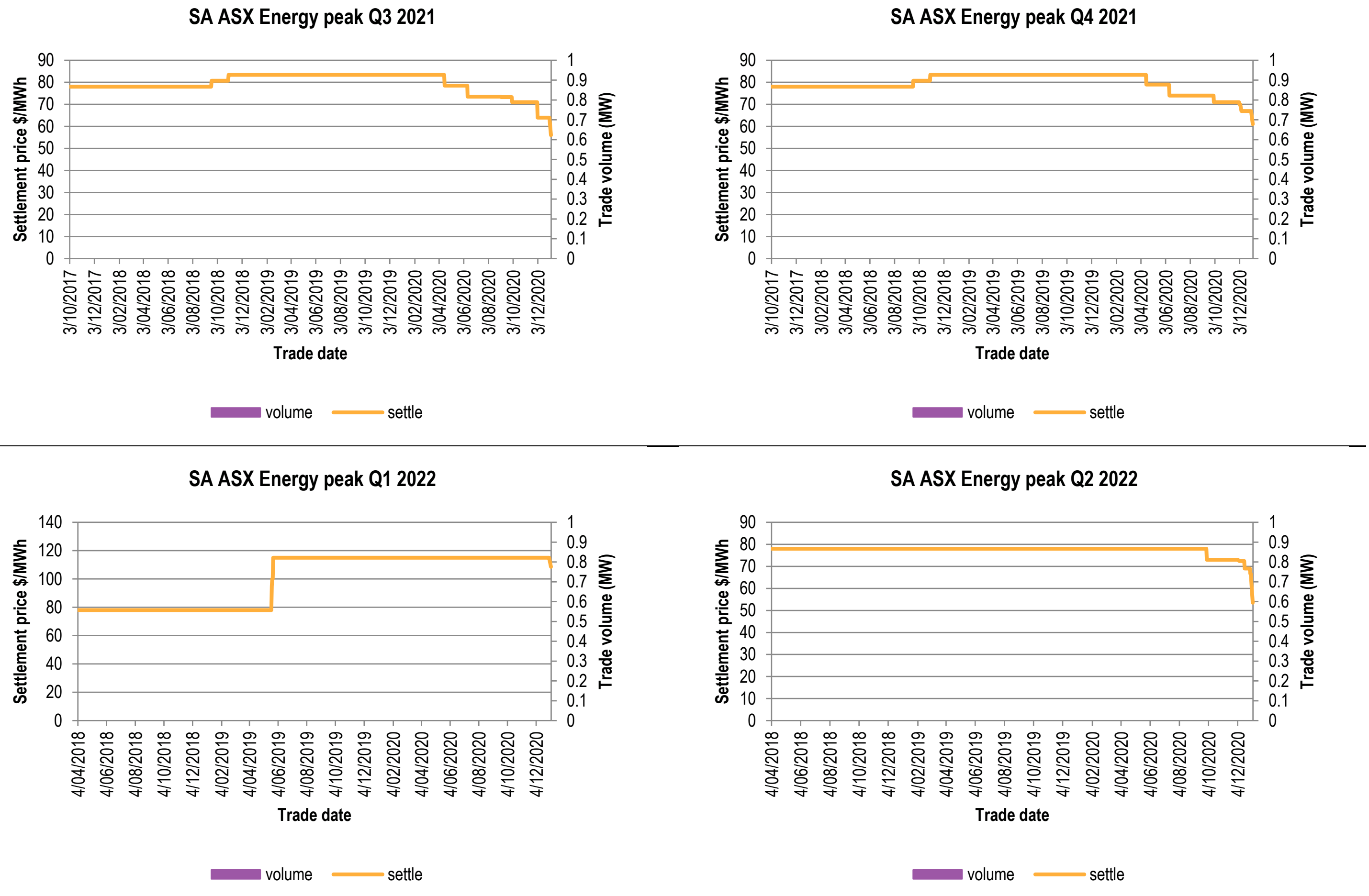
SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

FIGURE 4.14 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES – SOUTH AUSTRALIA



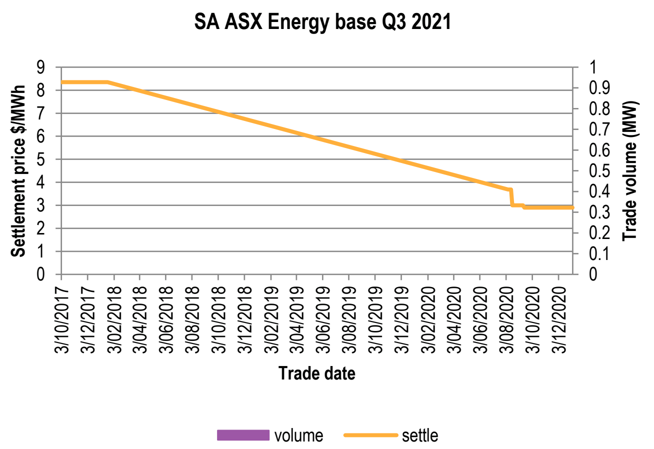
SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

FIGURE 4.15 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY PEAK FUTURES – SOUTH AUSTRALIA



SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

FIGURE 4.16 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS – SOUTH AUSTRALIA



No data for Q4 2021

No data for Q1 2022

No data for Q2 2022

SOURCE: ASX ENERGY DATA UP TO 5 JANUARY 2021

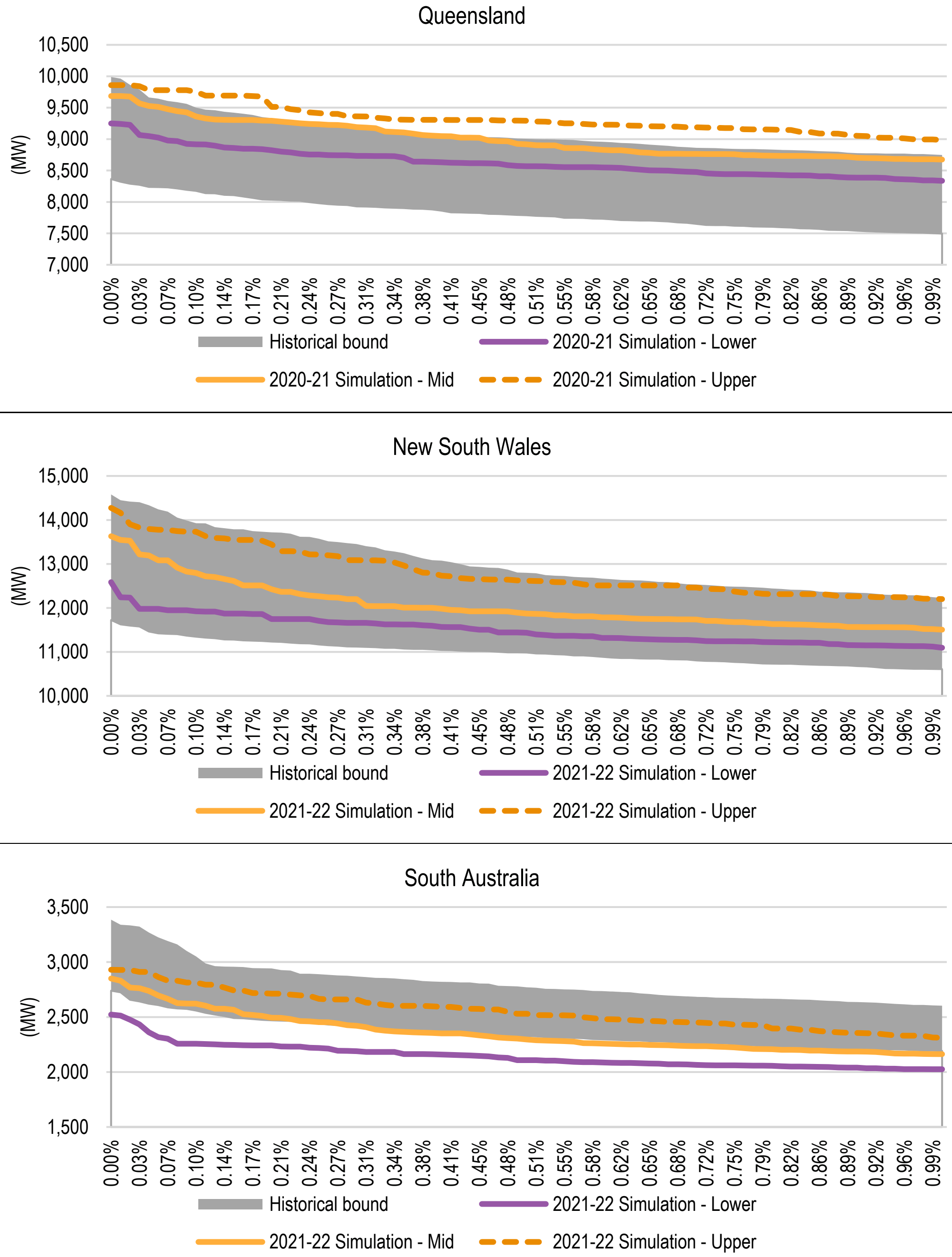
4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for the 550 simulations (50 demand and 11 outage sets).

Figure 4.17 shows the range of the upper one percent segment of the demand duration curves for the 50 simulated Queensland, New South Wales and South Australia system demand sets resulting from the methodology for 2021-22, along with the range in historical demands since 2011-12. The simulated demand sets represent the upper, lower, and middle of the range of demand duration curves across all 50 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2021-22 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 2021-22 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 2021-22 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 UPPER ONE PERCENT HOURLY SYSTEM DEMANDS



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[18] of the 2021-22 simulated demand sets ranging between:

- 28 percent and 34 percent compared with a range of 29 percent to 43 percent for the actual Energex NSLP between 2009-10 and 2019-20 (as shown in Figure 4.19)
- 37 percent and 42 percent compared with a range of 41 percent to 51 percent for the actual Essential NSLP between 2009-10 and 2019-20

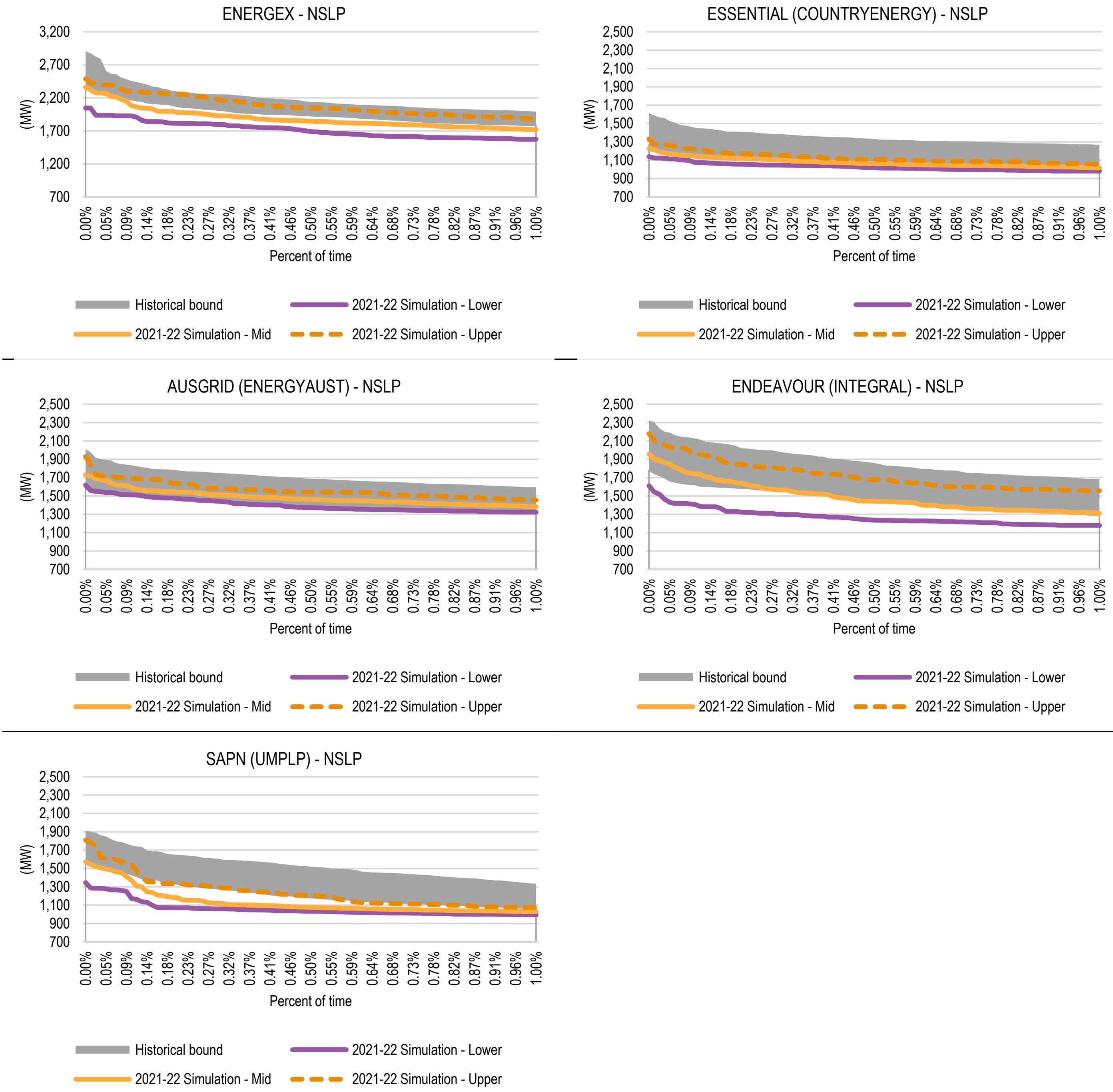
[18] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

— 27 percent and 32 percent compared with a range of 31 percent to 36 percent for the actual Ausgrid NSLP between 2009-10 and 2019-20
— 26 percent and 35 percent compared with a range of 31 percent to 39 percent for the actual Endeavour NSLP between 2009-10 and 2019-20
— 17 percent and 22 percent compared with a range of 21 percent to 33 percent for the actual SAPN NSLP between 2009-10 and 2019-20.

With the exception of the Endeavour and Ausgrid NSLPs, there has been an observable fall in the load factor in the actual NSLP in recent years due to an increase in penetration of rooftop solar PV panels.

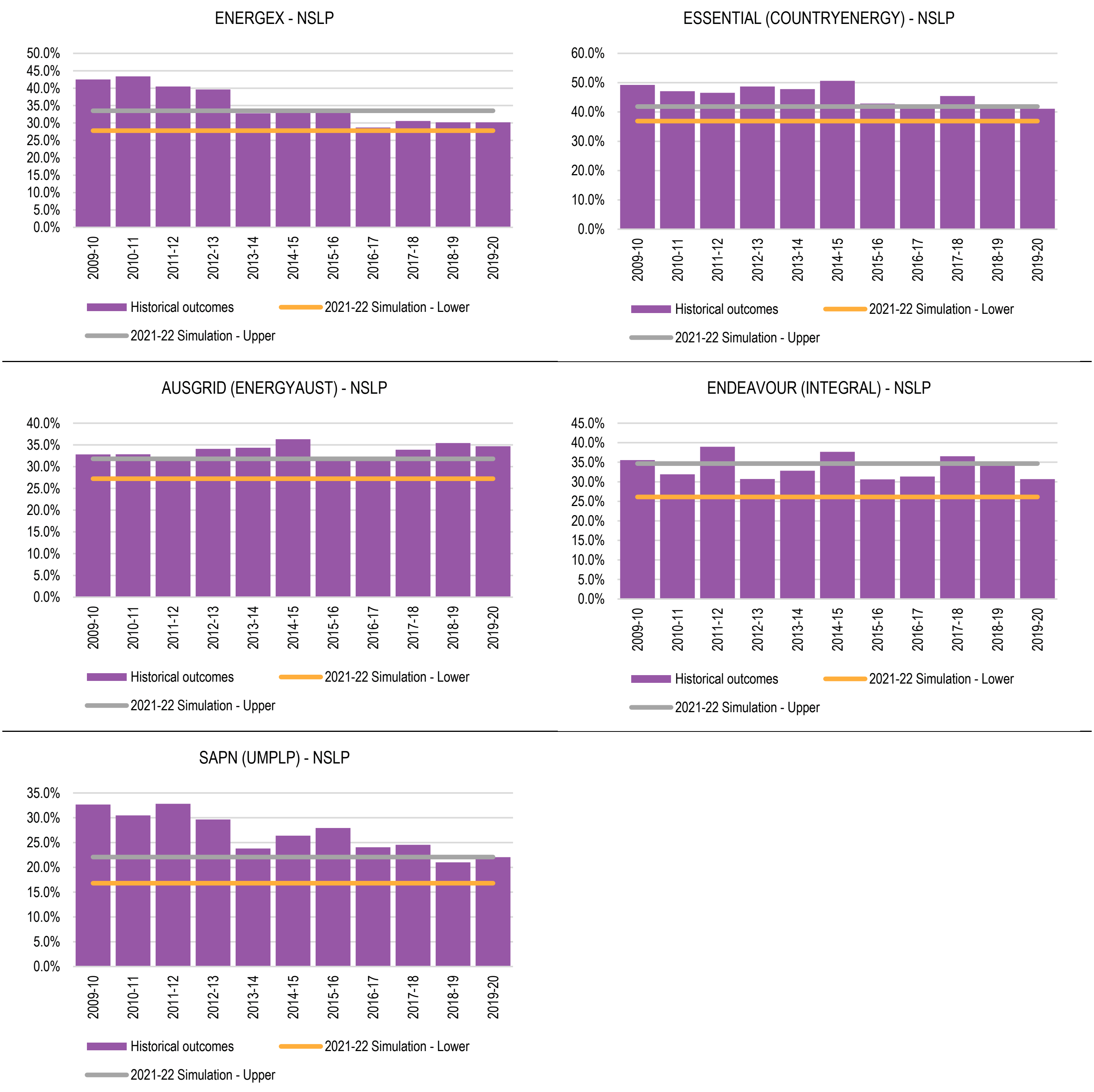
All other things being equal, the increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging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

FIGURE 4.18 UPPER ONE PERCENT HOURLY DEMANDS - NSLPS



SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

FIGURE 4.19 COMPARISON OF LOAD FACTOR OF 2021-22 SIMULATED HOURLY DEMAND DURATION CURVES AND HISTORICAL OUTCOMES - NSLPS



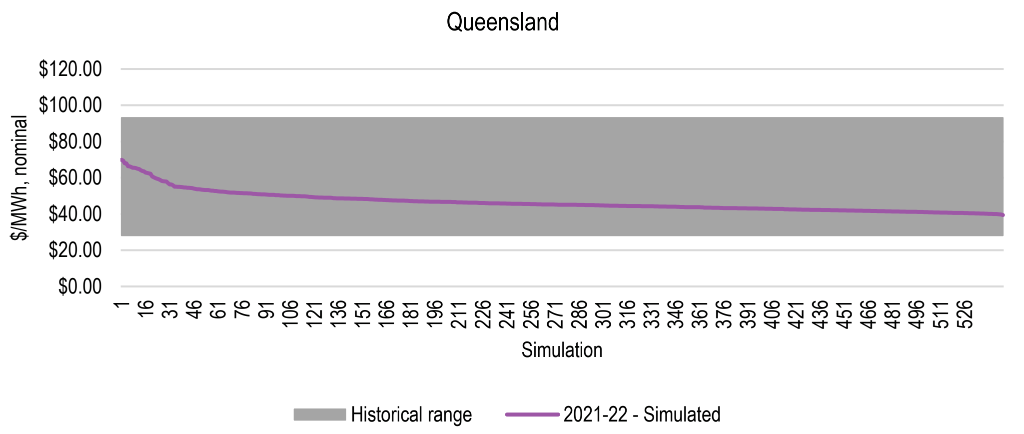
SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

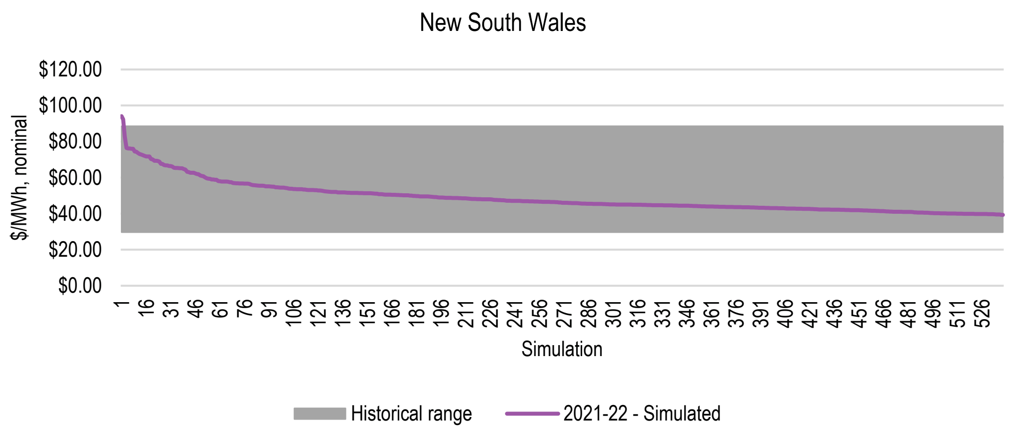
Figure 4.20 compares the modelled annual regional TWP for the 550 simulations for 2021-22 with the regional TWPs from the past 20 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential prices for 2021-22 when compared with the past 20 years of history.

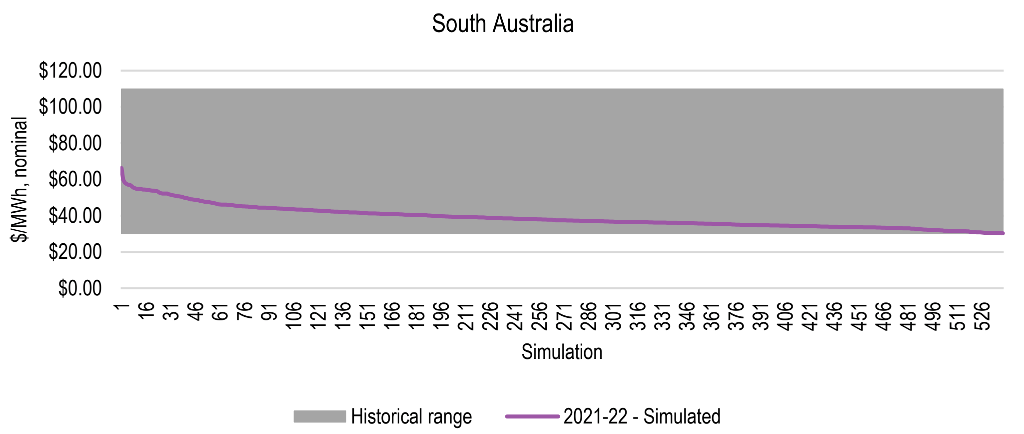
Unlike the simulation results for 2020-21 for DMO 2, the upper bound of the simulations for 2021-22 generally sit below the historic upper bound of actual outcomes. This is not surprising given the continued decline in gas prices and extensive commissioning of large-scale renewable energy capacity

ACIL Allen is satisfied that in an aggregate sense the distribution of the 550 simulations for 2021-22 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 2021-22 COMPARED WITH RANGE OF ACTUAL ANNUAL OUTCOMES IN PAST YEARS



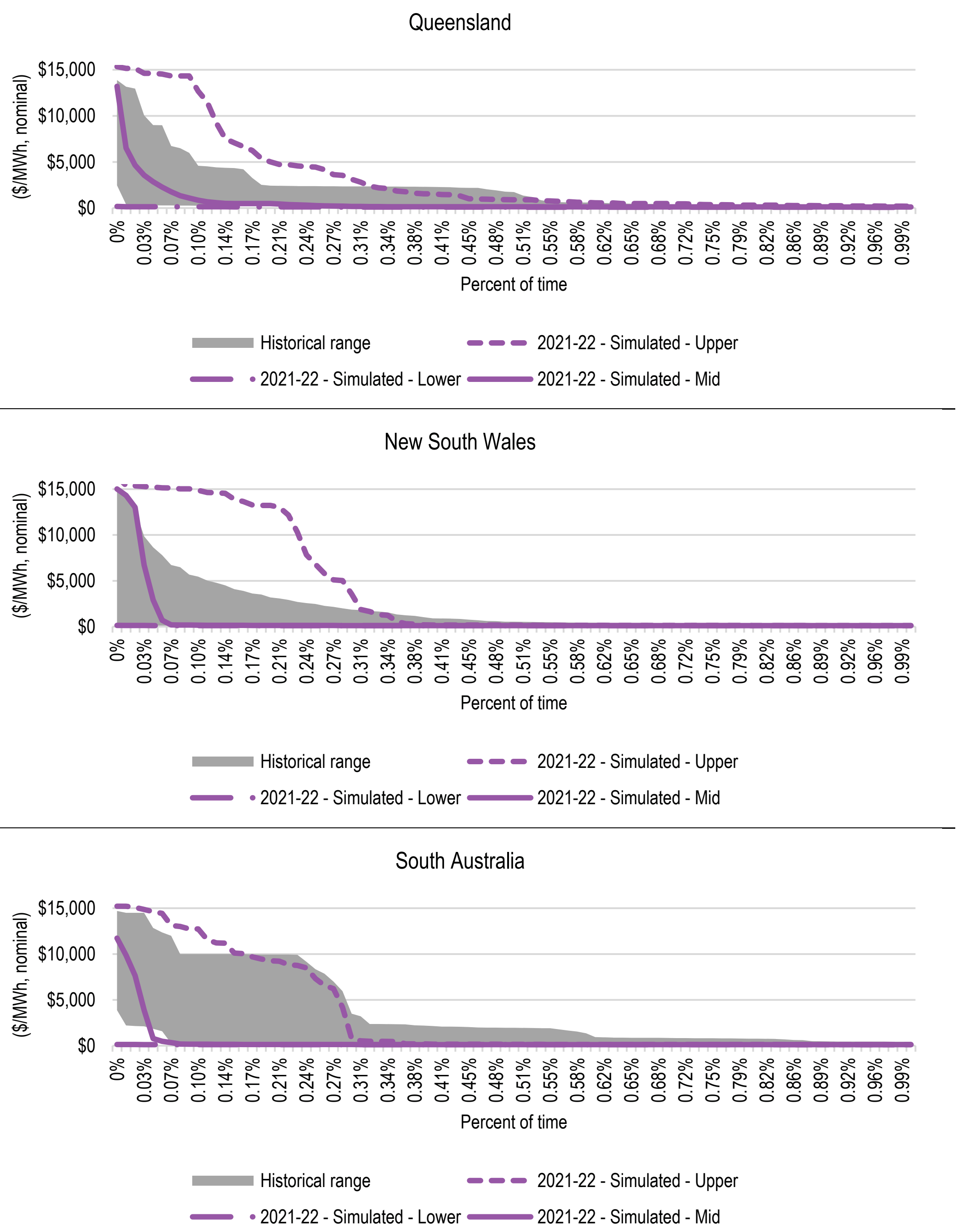




SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

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.

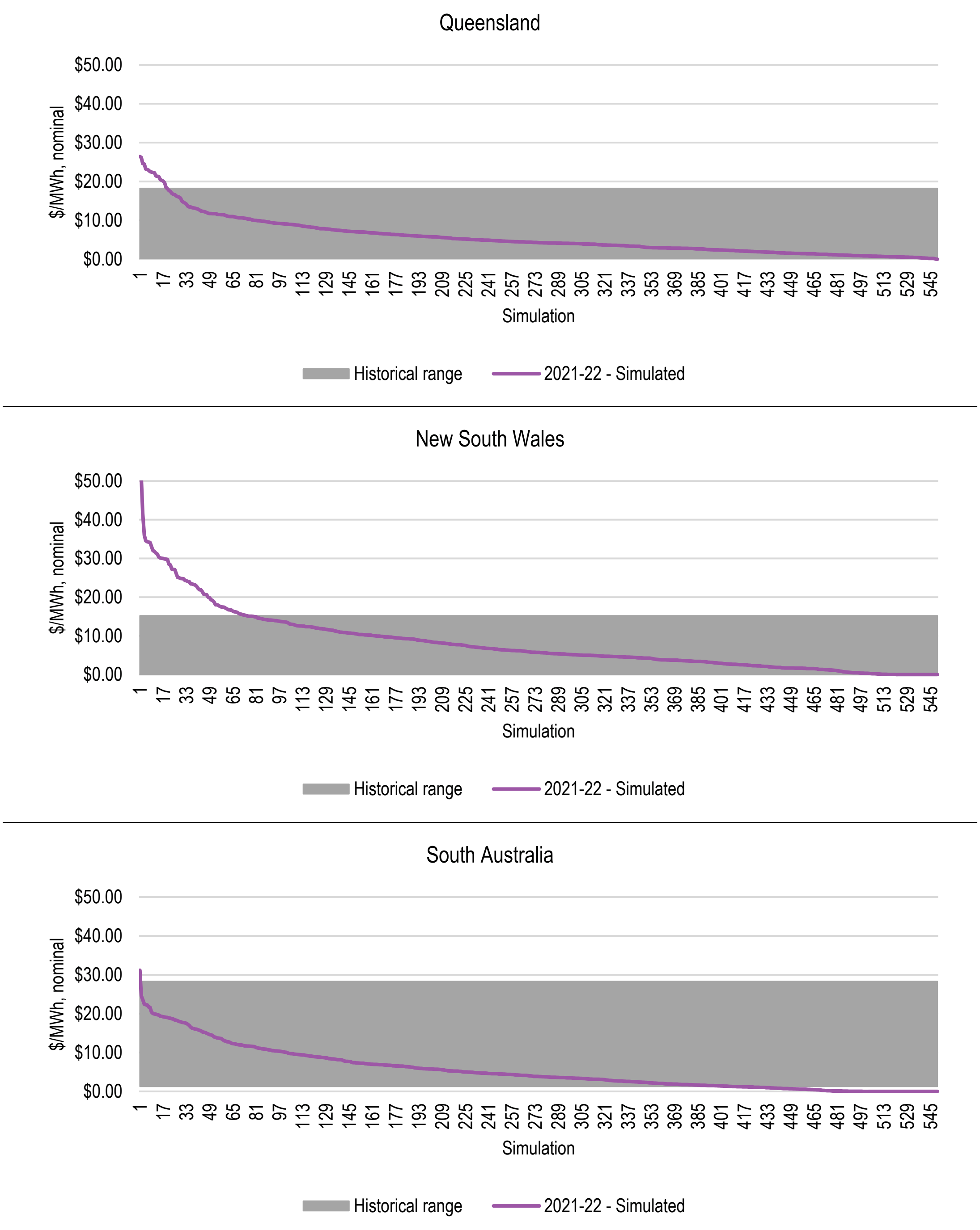
FIGURE 4.21 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND, NEW SOUTH WALES, AND SOUTH AUSTRALIA FOR 2021-22 AND RANGE OF HISTORICAL OUTCOMES



SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

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 550 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 550 simulations is consistent with those recorded in history as shown in Figure 4.22.

FIGURE 4.22 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND, NEW SOUTH WALES, AND SOUTH AUSTRALIA TWP BY PRICES ABOVE $300/MWH IN 2021-22 FOR SIMULATIONS COMPARED WITH RANGE OF ACTUAL OUTCOMES IN PAST YEARS



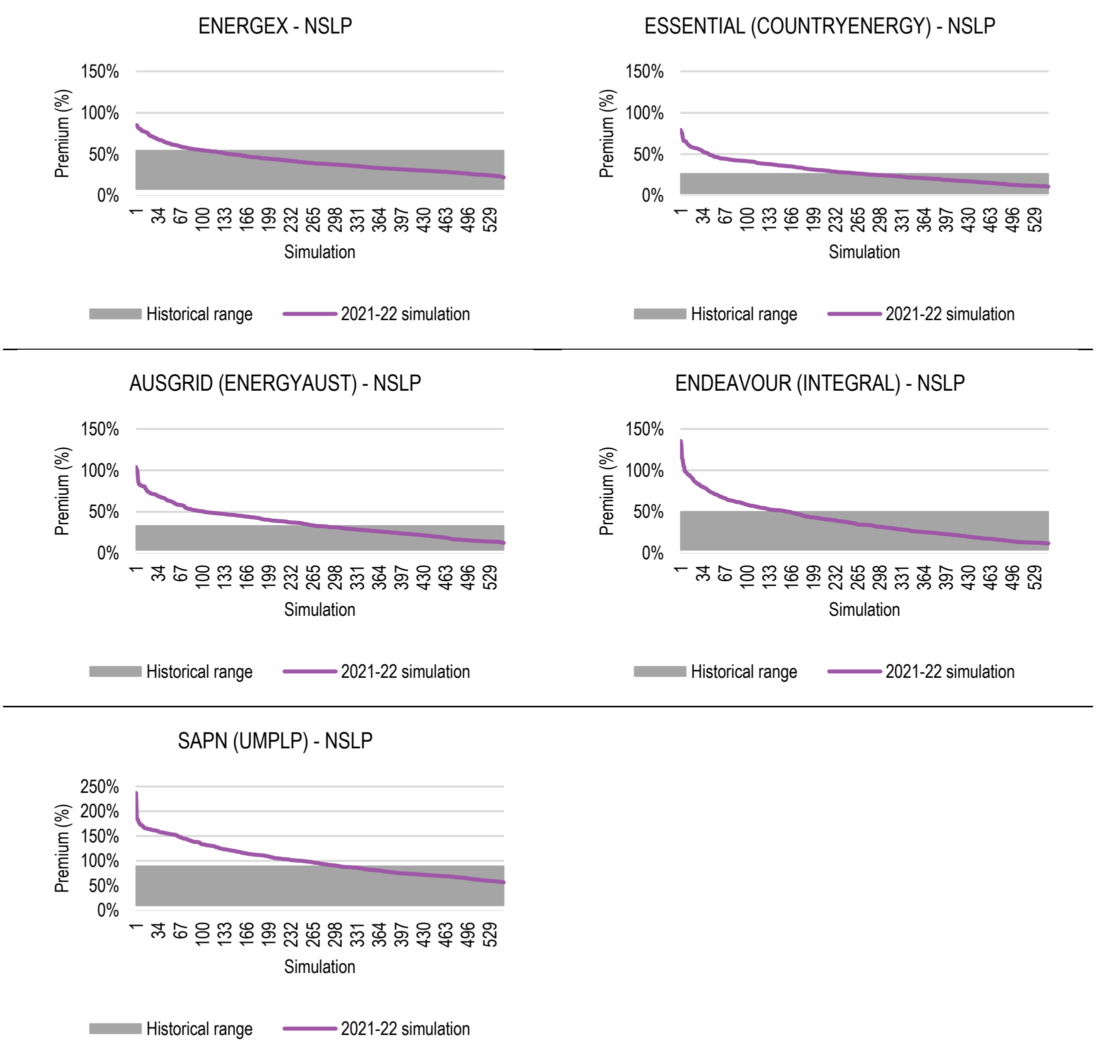
SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

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 10 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 550 simulations for 2021-22 for each NSLP, this percentage varies from 11 percent to 237 percent. The modelling suggests a greater range in the premium for 2021-22 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability with the commissioning of the 4,000 MW or so of renewable energy projects over the next 12 to18 months.

The comparison with actual outcomes over the past 10 years in Figure 4.23 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 550 simulations is sound.

FIGURE 4.23 SIMULATED ANNUAL DWP FOR NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR 2021-22 COMPARED WITH RANGE OF ACTUAL OUTCOMES IN PAST YEARS



SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 550 simulations cover the range of expected price outcomes for 2021-22 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 50 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 2021-22.

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 2021-22 are calculated for each NSLP for each quarter as follows, and are largely unchanged from DMO 2:

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

— The peak period contract volume is set to equal the 50th (Ausgrid, Essential, Endeavour, SAPN), 70th (Energex) percentile of the peak period hourly demands across all 50 demand sets minus the base contract volumes for the quarter.

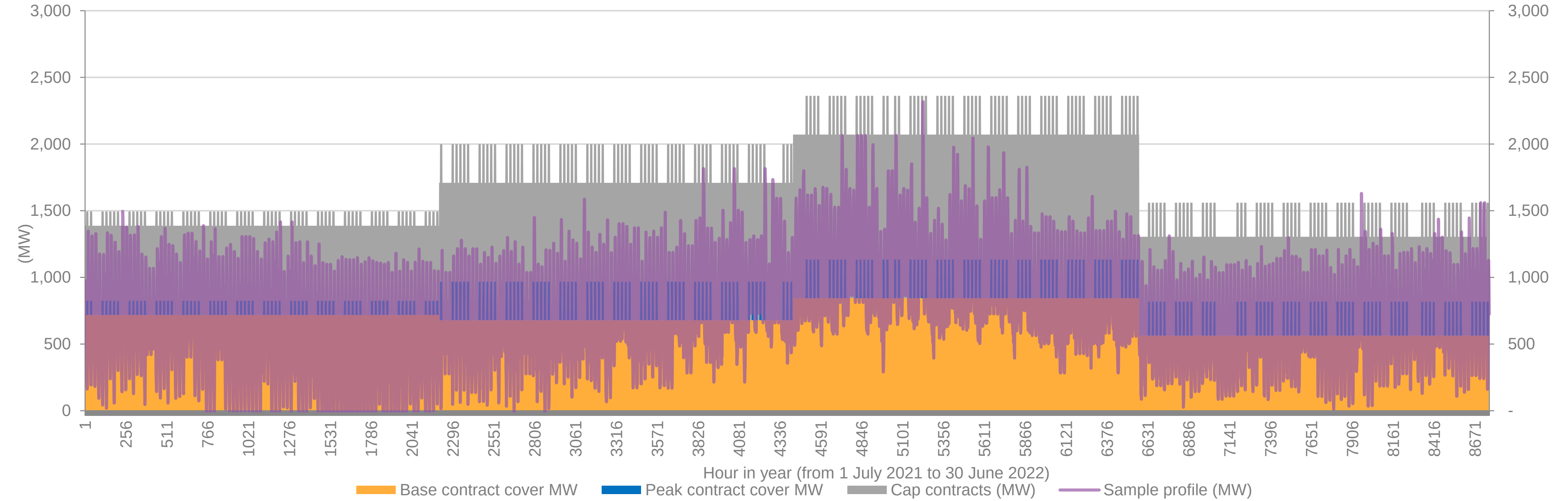
— The cap contract volume is set at 90 (SAPN), 100 (Energex, Essential, Endeavour), 110 (Ausgrid) per cent of the median of the annual peak demands across the 50 demand sets minus the base and peak contract volumes.

In other words, the same hourly hedge volumes (in MW terms) apply to each of the 50 demand sets for a given NSLP and year, and hence to each of the 550 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 50 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 550 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.24 to Figure 4.28.

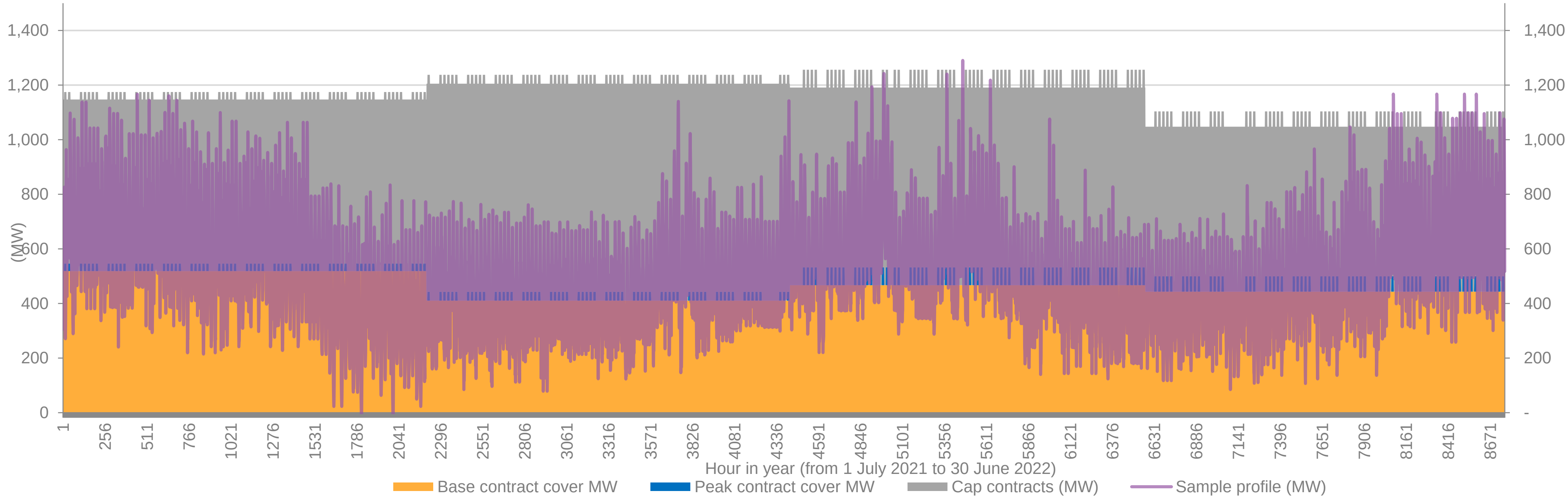
Generally, the contracting strategies place little reliance on peak contracts. This is not surprising – the trade weighted price differential between base and peak contracts in Queensland is about $12/MWh (on an annual basis), compared with a differential of $11/MWh in New South Wales, and $30/MWh in South Australia. 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 550 SIMULATIONS FOR 2021-22 FOR ENERGEX NSLP



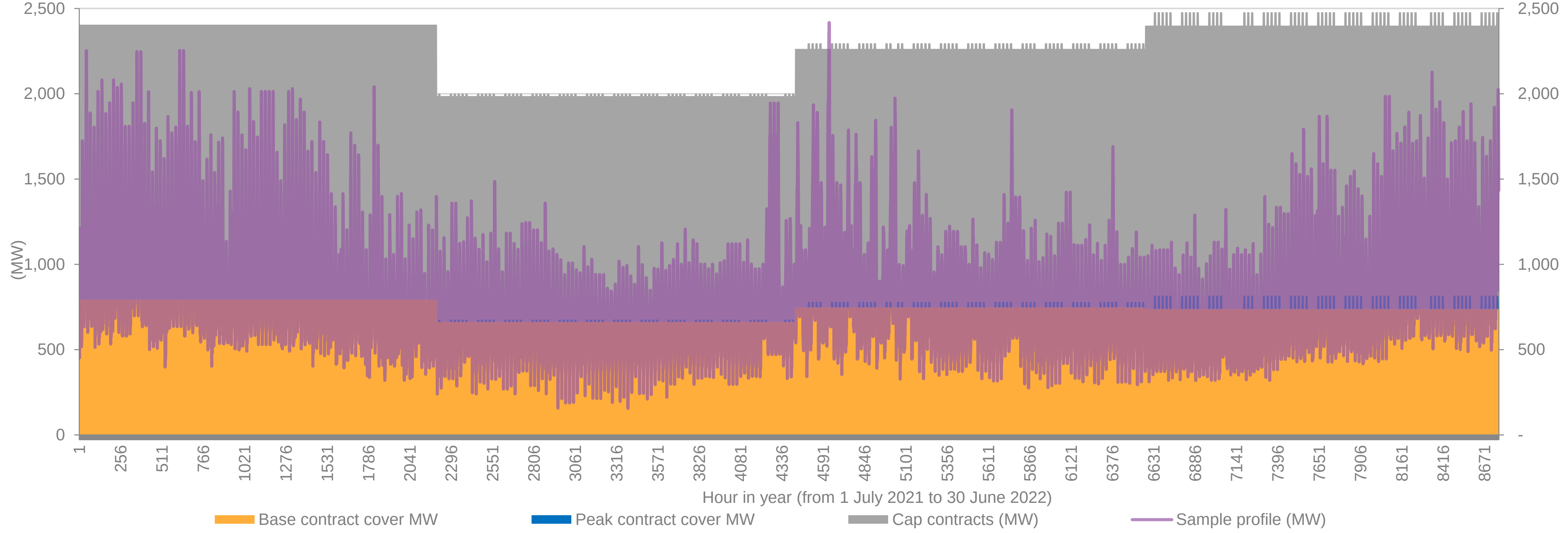
SOURCE: ACIL ALLEN

FIGURE 4.25 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 550 SIMULATIONS FOR 2021-22 FOR ESSENTIAL (COUNTRYENERGY) NSLP



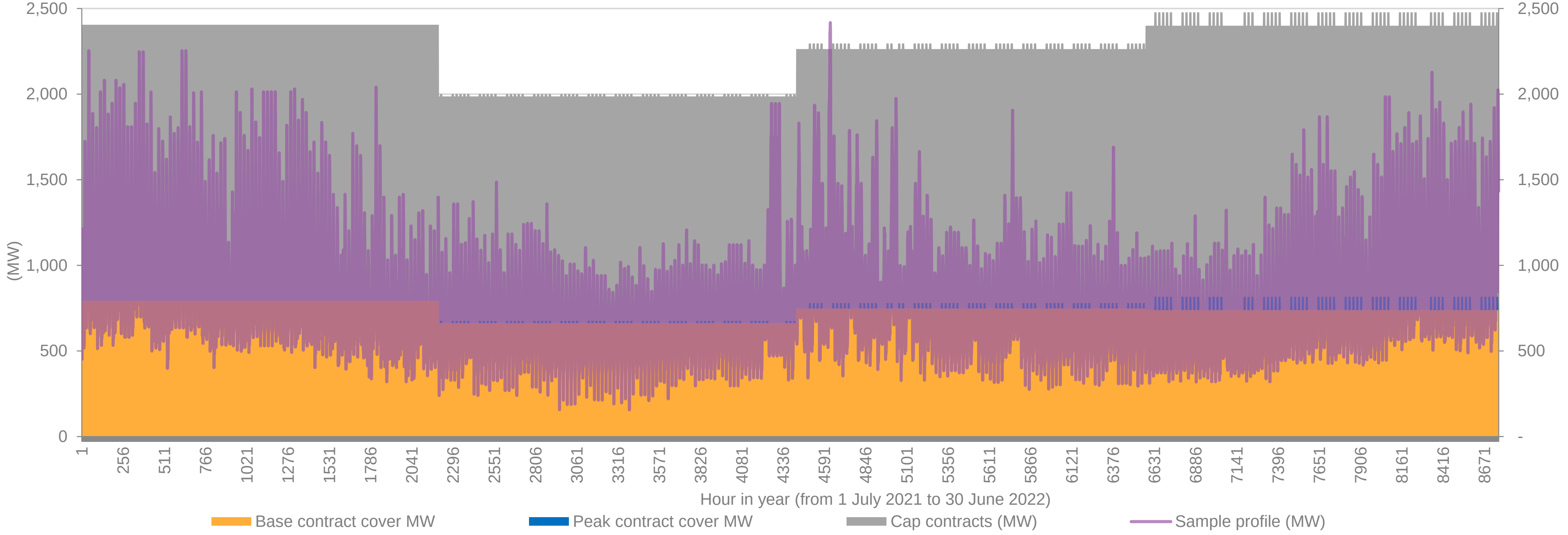
SOURCE: ACIL ALLEN

FIGURE 4.26 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 550 SIMULATIONS FOR 2021-22 FOR AUSGRID (ENERGYAUST) NSLP



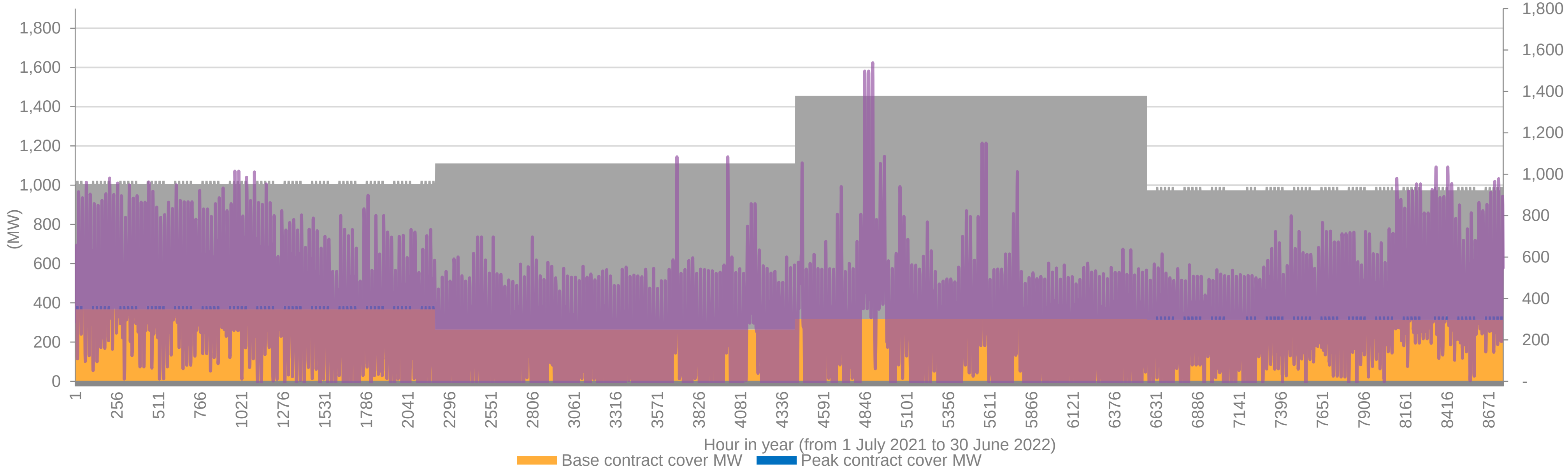
SOURCE: ACIL ALLEN

FIGURE 4.27 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 550 SIMULATIONS FOR 2021-22 FOR ENDEAVOUR (INTEGRAL) NSLP



SOURCE: ACIL ALLEN

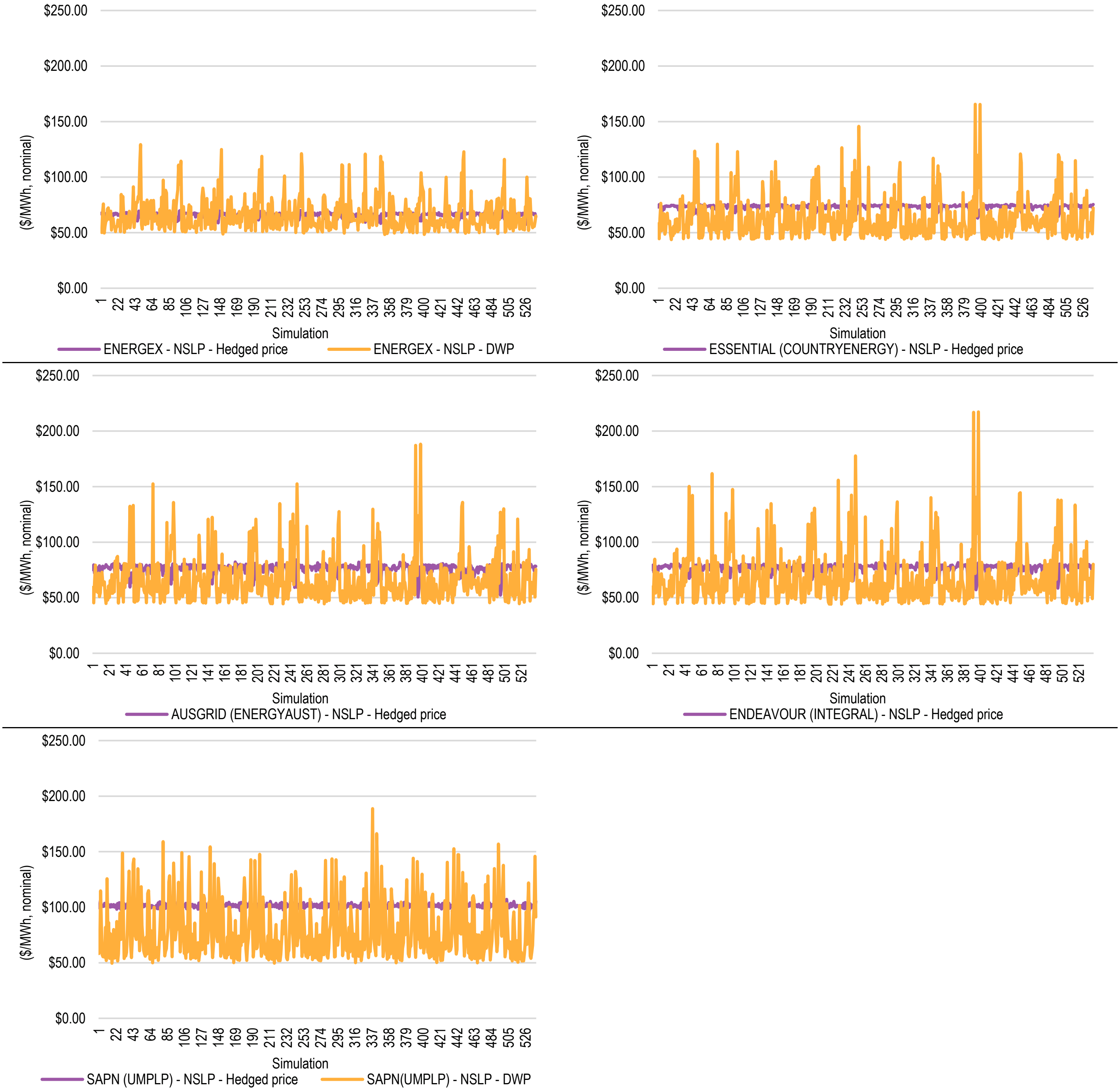
FIGURE 4.28 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 550 SIMULATIONS FOR 2021-22 FOR SAPN (UMPLP) NSLP



SOURCE: ACIL ALLEN

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 550 SIMULATIONS – 2021-22



SOURCE: ACIL ALLEN MODELLING

4.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the WEC is taken as the 95th percentile of the distribution containing 550 annual hedged prices. ACIL Allen's estimate of the WEC for each profile for 2021-22 are shown in Table 4.4.

TABLE 4.4 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2021-22 AT THE REGIONAL REFERENCE NODE

Settlement classes	2020-21	2021-22	Change from 2020-21 to 2021-22 (%)
Ausgrid - NSLP	$100.92	$80.24	-20.49%
Endeavour - NSLP	$101.07	$80.10	-20.75%
Essential - NSLP	$93.84	$75.26	-19.80%
Ausgrid - CLP1	$65.44	$56.46	-13.72%
Ausgrid - CLP2	$63.63	$55.21	-13.23%
Endeavour - CLP	$93.20	$75.62	-18.86%
Essential - CLP	$79.06	$66.95	-15.32%
Energex - NSLP	$82.45	$68.07	-17.44%
Energex - CLP1	$64.32	$51.27	-20.29%
Energex - CLP2	$65.99	$54.08	-18.05%
SAPN - NSLP	$132.61	$104.63	-21.10%
SAPN - CLP	$77.58	$65.79	-15.20%

SOURCE: ACIL ALLEN ANALYSIS

The 2021-22 WECs for the NSLPs and CLPs decrease by between 14 and 21 per cent compared with 2020-21 – reflecting the strong decrease on contract prices.

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[19]) 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 2021 and 2022 calendar years, with the costs averaged to estimate the 2021-22 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 2021 and 2022 from brokers TFS

— estimated Renewable Power Percentages (RPP) values for 2021 of 18.89 per cent and for 2022 of 18.89 per cent, respectively[20]

— the non-binding Small-scale Technology Percentage (STP) for 2021 of 23.94 per cent, as derived from CER data[21]

[19] 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.

[20] The RPP values for 2021 and 2022 were estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET targets for 2021 and 2022, respectively.

[21] Normally, ACIL Allen would consider the non-binding value published by the CER. However, in this case, the estimate is based on information contained in the CER's Q3 2020 Carbon Report http://www.cleanenergyregulator.gov.au/csf/market-information/Pages/quarterly-Market-report.aspx). The CER expects there to be 2.9 GW of rooftop PV installed in 2021 compared with an estimate of 2.35 used to calculate the non-binding STP of 19.4% for 2021. We have taken the ratio of 2.9/2.35 multiplied by 19.4% to get an STP of 23.94% for 2021.

— estimated STP value for 2022 of 23.94 per cent[22]
— CER clearing house price[23] for 2021 and 2022 for Small-scale Technology Certificates (STCs) of $40/MWh.

4.3.1 LRET

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

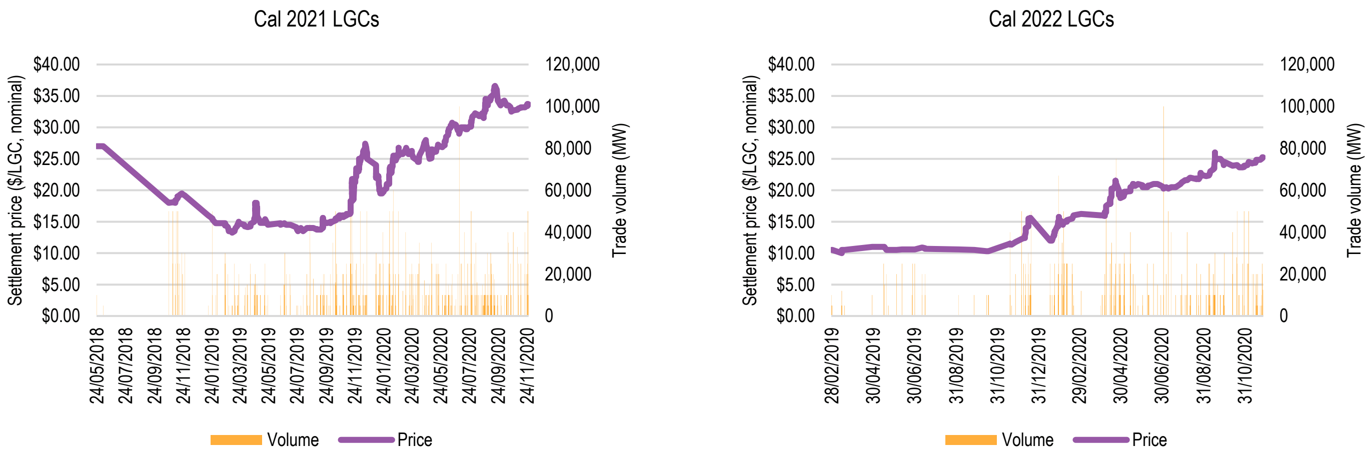
The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

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

ACIL Allen has estimated the average LGC price using LGC forward prices provided by broker TFS.

The LGC price used in assessing the cost of the scheme for 2021-22 is found by taking the trade-weighted average of the forward prices for the 2021 and 2022 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 4.30). The average LGC prices calculated from the TFS data are $23.52/MWh for 2021 and $18.53/MWh for 2022.

FIGURE 4.30 LGC PRICES FOR 2021 AND 2022 FOR 2021-22 ($/LGC, NOMINAL)



SOURCE: TFS AND ACIL ALLEN ANALYSIS

The RPP values are estimated using information up until 5 January 2021, by using the mandated target for 2021 and 2022 of 33 TWh and the CER's estimate of electricity acquisitions in 2021 of 174.7 TWh. ACIL Allen has assumed electricity acquisitions remain constant in 2022.

Key elements of the 2021 and 2022 RPP estimation are shown in Table 4.5.

[22] The STP value for 2022 assumes a similar level of STC creations and liable acquisitions in 2022 as in 2021.
[23] 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.

TABLE 4.5 ESTIMATING THE 2021 AND 2022 RPP VALUES

	2021	2022
LRET target, MWh (CER)	33,000,000	33,000,000
Relevant acquisitions minus exemptions, MWh (CER)	174,700,000	174,700,000
Estimated RPP	18.89%	18.89%

SOURCE: CER AND ACIL ALLEN ANALYSIS

ACIL Allen calculates the cost of complying with the LRET in 2021 and 2022 by multiplying the RPP values for 2021 and 2022 by the trade volume weighted average LGC prices for 2021 and 2022, respectively. The cost of complying with the LRET in 2021-22 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $3.97/MWh in 2021-22 as shown in Table 4.6.

TABLE 4.6 ESTIMATED COST OF LRET – 2021-22

	2021	2022	Cost of LRET 2021-22
RPP %	18.89%	18.89%	
Trade weighted average LGC price ($/LGC, nominal)	$23.52	$18.53	
Cost of LRET ($/MWh, nominal)	$4.44	$3.50	$3.97

SOURCE: CER, TFS, ACIL ALLEN ANALYSIS

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 2021-22.

The estimate for 2021-22, which incorporates all available information to date, uses the following inputs:

— ACIL Allen's estimate of the 2021 STP of 23.94 per cent (equivalent to 41.8 million STCs as a proportion of total estimated electricity consumption for the 2021 year).
  – This is based on information contained in the CER's Q3 2020 Carbon Report, in which the CER expects there to be 2.9 GW of rooftop PV installations in 2021 compared with a previous estimate of 2.35 GW used to calculate the earlier non-binding estimate of the STP of 19.4 per cent for 2021.
  – ACIL Allen has taken 2.9/2.35 * 19.4 per cent to get an updated estimate of the STP of 23.94 per cent for 2021.

— ACIL Allen's estimate of the STP value for 2022 of 23.94 per cent – assuming similar level of STC creation as in 2021.

ACIL Allen estimates the cost of complying with SRES to be $9.58/MWh in 2021-22 as set out in Table 4.7.

TABLE 4.7 ESTIMATED COST OF SRES – 2021-22

	2021	2022	Cost of SRES 2021-22
STP %	23.94%	23.94%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$9.58	$9.58	$9.58

SOURCE: ACIL ALLEN ANALYSIS

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2021-22 as set out in Table 4.8.

Since the 2020-21 estimate, the cost of LRET has decreased by around 20 per cent, driven by lower LGC prices in 2021-22 and the cost of SRES has increased by three per cent, driven by slightly higher expected installations in 2021 and 2022.

TABLE 4.8 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH, NOMINAL)

	2020-21	2021-22	Change
LRET	$4.95	$3.97	($0.98)
SRES	$9.31	$9.58	$0.27
Total	$14.26	$13.55	($0.71)

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 2021 and 2022 of 8.5 per cent, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2021 and 2022 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 2021-22, as set out in Table 4.9. The 2021-22 estimate of $2.31/MWh is up slightly from the 2020-21 estimate of $2.09/MWh

TABLE 4.9 ESTIMATED COST OF ESS ($/MWH, NOMINAL) – 2021-22

	2021	2022	Cost of ESS 2021-22
ESS target	8.5%	8.5%	
Average ESC price ($/MWh, nominal)	$26.93	$27.50	
Cost of ESS ($/MWh, nominal)	$2.29	$2.34	$2.31

SOURCE: IPART, TFS

4.3.5 South Australia Retailer Energy Efficiency Scheme (REES)

The Retailer Energy Efficiency Scheme (REES) is a South Australian Government energy efficiency scheme that provides incentives for South Australian households and businesses to save energy. It does this via energy efficiency and audit targets to be met by electricity and gas retailers with customers in South Australia.

In the AEMC's 2018 price trends methodology report, the cost of the REES was sourced using data from the relevant jurisdiction, although there is no link to the exact location of this data.[24]

In the AEMC's 2020 price trends report[25], the cost of REES appears to be unchanged from the 2018 and 2019 reports.

In the AEMC's report, the estimated cost of REES, 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,

[24] Table 8.5, page 49 at https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf
[25] Published on 21 December 2020 at: https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2020

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 REES and given that the cost as estimated by AEMC is a very small component of the overall cost of the retail bill, ACIL Allen has used the estimates of the cost of REES provided in the latest AEMC price trends report of $2.50/MWh.

4.4 Estimation of other energy costs

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

- Market fees and charges including:
  - NEM management fees
  - Ancillary services costs.
- Pool and hedging prudential costs
- The Reliability and Emergency Reserve Trader (RERT).

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), and the Energy Consumers Australia (ECA)[26].

It is worth noting that in DMO 2 the National Transmission Planner (NTP) was included in this cost category. However, the recovery of this item has since 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 2021-22.

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2020-21* the fees for 2021-22 are $0.49/MWh. The breakdown of total fees is shown in Table 4.10.

TABLE 4.10 NEM MANAGEMENT FEES ($/MWH, NOMINAL) – 2021-22

Cost category	2020-21	2021-22
NEM fees (admin, registration, etc.)	$0.56	$0.37
FRC - electricity	$0.077	$0.078
NTP - electricity	$0.040	$0.00
ECA - electricity	$0.032	$0.040
Total NEM management fees	**$0.71**	**$0.49**

SOURCE: AEMO

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 of currently available NEM ancillary services data as a basis for 2021-22, the estimates cost of ancillary services is shown in Table 4.11.

Generally, there has been a decrease in weekly ancillary service costs as a result of additional supply being commissioned that can offer services to this relatively small market. This results in a reasonable decrease in ancillary service costs in Queensland and New South Wales. However, there have been occasions over the past 12 months (in early 2020) in which the market in South Australia islanded from the remainder of the market, and during these periods the cost of ancillary services increased substantially – leading to an overall increase across the year for South Australia. Providing there are no islanding events between this Draft Determination and the Final Determination in South Australia, the ancillary service costs will likely decrease in South Australia for the Final Determination.

[26] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2020-21* 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.

TABLE 4.11 ANCILLARY SERVICES ($/MWH, NOMINAL) – 2021-22

Region	2020-21	2021-22
Queensland	$1.53	$0.45
New South Wales	$1.53	$0.31
South Australia	$1.53	$4.31

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 Ausgrid NSLP gives an estimated MCL of $9,553.

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 Ausgrid NSLP is $6,591/42 = $156.94/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 $156.94 gives $0.45/MWh for Ausgrid NSLP, as shown in Table 4.13**.**

The components of the AEMO prudential costs for each of the other jurisdictions' NSLPs are shown in Table 4.12 to Table 4.16**.**

TABLE 4.12 AEMO PRUDENTIAL COSTS FOR ENERGEX NSLP – 2021-22

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$73.68	$38.84	$40.41
Participant Risk Adjustment Factor	1.5509	1.3731	1.5483
OS Volatility factor	1.56	1.28	1.34
PM Volatility factor	2.90	1.79	1.91
OSL	$8,547	$3,080	$4,016

Factor	Summer	Winter	Shoulder
PML	$1,709	$616	$803
MCL	$10,256	$3,696	$4,819
Average MCL		$6,243	
AEMO prudential cost ($/MWh, nominal)		**$0.43**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.13 AEMO PRUDENTIAL COSTS FOR AUSGRID NSLP – 2021-22

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$79.48	$48.94	$38.49
Participant Risk Adjustment Factor	1.6611	1.2970	1.1406
OS Volatility factor	1.59	1.32	1.34
PM Volatility factor	3.23	1.88	2.04
OSL	$10,416	$3,674	$2,419
PML	$2,083	$735	$484
MCL	$12,499	$4,408	$2,903
Average MCL		$6,591	
AEMO prudential cost ($/MWh, nominal)		**$0.45**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.14 AEMO PRUDENTIAL COSTS FOR ENDEAVOUR NSLP – 2021-22

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$79.48	$48.94	$38.49
Participant Risk Adjustment Factor	1.8193	1.1633	1.1913
OS Volatility factor	1.59	1.32	1.34
PM Volatility factor	3.23	1.88	2.04
OSL	$11,939	$3,120	$2,582
PML	$2,388	$624	$516
MCL	$14,327	$3,745	$3,099
Average MCL		$7,039	
AEMO prudential cost ($/MWh, nominal)		**$0.48**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.15 AEMO PRUDENTIAL COSTS FOR ESSENTIAL NSLP – 2021-22

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$79.48	$48.94	$38.49
Participant Risk Adjustment Factor	1.3521	1.1360	1.2032
OS Volatility factor	1.59	1.32	1.34
PM Volatility factor	3.23	1.88	2.04
OSL	$7,649	$3,011	$2,621
PML	$1,530	$602	$524
MCL	$9,179	$3,614	$3,145
Average MCL		$5,303	
AEMO prudential cost ($/MWh, nominal)		**$0.36**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.16 AEMO PRUDENTIAL COSTS FOR SAPN NSLP – 2021-22

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$76.61	$45.51	$38.35
Participant Risk Adjustment Factor	3.6088	1.2161	1.9244
OS Volatility factor	1.80	1.47	1.38
PM Volatility factor	4.78	2.24	1.88
OSL	$36,396	$3,454	$5,439
PML	$7,279	$691	$1,088
MCL	$43,675	$4,145	$6,527
Average MCL		$18,039	
AEMO prudential cost ($/MWh, nominal)		**$1.24**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

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 New South Wales 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, 13 percent for a peak contract and 28 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, $9,400 for a peak contract and $5,500 for a cap contract

— the spot isolation rate currently set at $1,500 for a base contract, $4,400 for a peak contract and $400 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 New South Wales region in Table 4.18. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 6.45 per cent but adjusted for an assumed 0.10 per cent return on cash lodged with the clearing (giving a net funding cost of 6.35 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 4.17 to Table 4.19, respectively.

TABLE 4.17 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – QUEENSLAND 2021-22

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$48.28	$23,000	$0.67
Peak	$60.34	$24,000	$1.62
Cap	$4.37	$9,000	$0.26

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

TABLE 4.18 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – NEW SOUTH WALES 2021-22

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$60.17	$26,000	$0.75
Peak	$73.57	$23,000	$1.55
Cap	$6.84	$11,000	$0.32

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

TABLE 4.19 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – SOUTH AUSTRALIA 2021-21

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$57.07	$41,000	$1.19
Peak	$69.58	$42,000	$2.83
Cap	$7.18	$17,000	$0.49

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

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 4.20 to Table 4.24.

TABLE 4.20 HEDGE PRUDENTIAL FUNDING COSTS FOR ENERGEX NSLP – 2021-22

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.67	1.0074	$0.67
Peak	$1.62	0.1460	$0.24
Cap	$0.26	1.3165	$0.34
Total cost		**$1.25**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.21 HEDGE PRUDENTIAL FUNDING COSTS FOR AUSGRID NSLP – 2021-22

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.75	0.9064	$0.68
Peak	$1.55	0.0100	$0.02
Cap	$0.32	2.2711	$0.72
Total cost		**$1.42**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.22 HEDGE PRUDENTIAL FUNDING COSTS FOR ENDEAVOUR NSLP – 2021-22

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.75	0.9225	$0.70
Peak	$1.55	0.0109	$0.02
Cap	$0.32	1.8081	$0.58
Total cost		**$1.29**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.23 HEDGE PRUDENTIAL FUNDING COSTS FOR ESSENTIAL NSLP – 2021-22

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.75	0.9137	$0.69
Peak	$1.55	0.0381	$0.06
Cap	$0.32	1.3807	$0.44
Total cost		**$1.19**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.24 HEDGE PRUDENTIAL FUNDING COSTS FOR SAPN NSLP – 2021-22

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.19	0.9841	$1.17
Peak	$2.83	0.0111	$0.03
Cap	$0.49	2.6301	$1.30
Total cost		**$2.50**	

SOURCE: ACIL ALLEN ANALYSIS

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2021-22 as set out in Table 4.25. Prudential costs for 2021-22 are generally lower than 2020-21 due to lower hedge prices and lower expected price volatility across 2021-22.

TABLE 4.25 TOTAL PRUDENTIAL COSTS ($/MWH, NOMINAL) – 2021-22

Jurisdiction	2020-21	2021-22
Ausgrid NSLP	$2.25	$1.87
Endeavour NSLP	$2.05	$1.77
Essential NSLP	$1.66	$1.55
Energex NSLP	$1.70	$1.68
SAPN NSLP	$4.25	$3.73

4.4.4 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 take the RERT costs as published by AEMO for the 12-month period prior to the Final Determination.

At the time of writing this report for the Draft Determination, AEMO has activated the RERT once for the 12-month period prior to the Final Determination. This activation occurred on 17 December 2020 for the New South Wales region due to a forecast Lack of Reserve Condition 2. On 22 December 2020, AEMO estimated the payments for this activation to be $199,500. When dividing this value by the total energy requirements in New South Wales, the cost of the RERT (to date) is less than about 0.3 of a cent per MWh (or $0.00 when rounded to the nearest cent).

Therefore, the RERT costs are currently set of $0.00/MWh for each New South Wales, Queensland, and South Australia. These costs will be updated for the Final Determination if subsequent data have been published by AEMO.

4.4.5 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.29**,** for the 2021-22 Draft Determination and is compared with the costs for 2020-21.

TABLE 4.26 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – AUSGRID NSLP

Cost category	2020-21	2021-22
NEM management fees	$0.71	$0.49
Ancillary services	$1.53	$0.31

Cost category	2020-21	2021-22
Hedge and pool prudential costs	$2.25	$1.87
Reserve and Emergency Reserve Trader	$0.36	$0.00
Total	**$4.85**	**$2.67**

TABLE 4.27 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ENDEAVOUR NSLP

Cost category	2020-21	2021-22
NEM management fees	$0.71	$0.49
Ancillary services	$1.53	$0.31
Hedge and pool prudential costs	$2.05	$1.77
Reserve and Emergency Reserve Trader	$0.36	$0.00
Total	**$4.65**	**$2.57**

TABLE 4.28 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ESSENTIAL NSLP

Cost category	2020-21	2021-22
NEM management fees	$0.71	$0.49
Ancillary services	$1.53	$0.31
Hedge and pool prudential costs	$1.66	$1.55
Reserve and Emergency Reserve Trader	$0.36	$0.00
Total	**$4.26**	**$2.35**

TABLE 4.29 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ENERGEX NSLP

Cost category	2020-21	2021-22
NEM management fees	$0.71	$0.49
Ancillary services	$1.53	$0.45
Hedge and pool prudential costs	$1.70	$1.68
Reserve and Emergency Reserve Trader	$0.00	$0.00
Total	**$3.94**	**$2.624**

TABLE 4.30 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – SAPN NSLP

Cost category	2020-21	2021-22
NEM management fees	$0.71	$0.49
Ancillary services	$1.53	$4.31
Hedge and pool prudential costs	$4.25	$3.73
Reserve and Emergency Reserve Trader	$0.00	$0.00
Total	**$6.49**	**$8.53**

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 2021-22 are based on the estimates for 2020-21 Final Determination. Although AEMO recently published the preliminary MLF estimates for 2021-22 in late December 2020 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 2021-22 will be based on the 2021-22 MLFs and DLFs to be published by AEMO in early April 2021.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2021-22 is shown in Table 4.31**.**

TABLE 4.31 ESTIMATED TRANSMISSION AND DISTRIBUTION LOSSES

Settlement class	2020-21			2021-22		
	Distribution losses	Transmission losses	Total loss factor	Distribution losses	Transmission losses	Total loss factor
Ausgrid - NSLP	4.79%	0.16%	1.050	4.79%	0.16%	1.050
Endeavour - NSLP	6.87%	-0.63%	1.062	6.87%	-0.63%	1.062
Essential - NSLP	6.64%	-1.07%	1.055	6.64%	-1.07%	1.055
Ausgrid - CLP1	5.14%	0.16%	1.053	5.14%	0.16%	1.053
Ausgrid - CLP2	5.14%	0.16%	1.053	5.14%	0.16%	1.053
Endeavour - CLP	6.87%	-0.63%	1.062	6.87%	-0.63%	1.062
Essential - CLP	6.64%	-1.07%	1.055	6.64%	-1.07%	1.055
Energex - NSLP	5.20%	0.70%	1.059	5.20%	0.70%	1.059
Energex – CLP31	5.20%	0.70%	1.059	5.20%	0.70%	1.059
Energex – CLP33	5.20%	0.70%	1.059	5.20%	0.70%	1.059
SAPN - NSLP	10.70%	0.08%	1.108	10.70%	0.08%	1.108
SAPN - CLP	10.70%	0.08%	1.108	10.70%	0.08%	1.108

SOURCE: AEMO, ACIL ALLEN ANALYSIS

As described by AEMO[27], 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)*

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 2021-22 total energy costs (TEC) for the Draft Determination for each of the profiles are presented in Table 4.32 to Table 4.33.

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

TABLE 4.32 ESTIMATED TEC FOR 2021-22 ($/MWH, NOMINAL) - DRAFT DETERMINATION

Profile	2020-21 Total energy costs at the customer terminal ($/MWh, nominal)	2021-22 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2020-21 to 2021-22 ($/MWh, nominal)	Change from 2020-21 to 2021-22 (%, nominal)
Ausgrid - NSLP	$128.23	$103.71	($24.52)	-19.12%
Endeavour - NSLP	$129.63	$104.64	($24.99)	-19.28%
Essential - NSLP	$120.75	$98.61	($22.14)	-18.34%
Ausgrid - CLP1	$91.24	$78.96	($12.28)	-13.46%
Ausgrid - CLP2	$89.33	$77.65	($11.68)	-13.08%
Endeavour - CLP	$121.28	$99.88	($21.40)	-17.65%
Essential - CLP	$105.15	$89.84	($15.31)	-14.56%
Energex - NSLP	$106.59	$89.21	($17.38)	-16.31%
Energex – CLP31	$87.39	$71.42	($15.97)	-18.27%
Energex – CLP33	$89.16	$74.40	($14.76)	-16.55%
SAPN - NSLP	$172.69	$143.16	($29.53)	-17.10%
SAPN - CLP	$111.72	$100.13	($11.59)	-10.37%

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.33 ESTIMATED TEC FOR 2021-22 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 ($/MWh, nominal)	Environ mental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$80.24	$2.67	1.050	$4.15	$87.06	$3.97	$9.58	$2.31	$0.79	$16.65	$103.71
Endeavour - NSLP	$80.10	$2.57	1.062	$5.13	$87.80	$3.97	$9.58	$2.31	$0.98	$16.84	$104.64
Essential - NSLP	$75.26	$2.35	1.055	$4.27	$81.88	$3.97	$9.58	$2.31	$0.87	$16.73	$98.61
Ausgrid - CLP1	$56.46	$2.67	1.053	$3.13	$62.26	$3.97	$9.58	$2.31	$0.84	$16.70	$78.96
Ausgrid - CLP2	$55.21	$2.67	1.053	$3.07	$60.95	$3.97	$9.58	$2.31	$0.84	$16.70	$77.65
Endeavour - CLP	$75.62	$2.57	1.062	$4.85	$83.04	$3.97	$9.58	$2.31	$0.98	$16.84	$99.88
Essential - CLP	$66.95	$2.35	1.055	$3.81	$73.11	$3.97	$9.58	$2.31	$0.87	$16.73	$89.84
Energex - NSLP	$68.07	$2.62	1.059	$4.17	$74.86	$3.97	$9.58	$0.00	$0.80	$14.35	$89.21
Energex - CLP1	$51.27	$2.62	1.059	$3.18	$57.07	$3.97	$9.58	$0.00	$0.80	$14.35	$71.42
Energex - CLP2	$54.08	$2.62	1.059	$3.35	$60.05	$3.97	$9.58	$0.00	$0.80	$14.35	$74.40
SAPN - NSLP	$104.63	$8.53	1.108	$12.22	$125.38	$3.97	$9.58	$2.50	$1.73	$17.78	$143.16
SAPN - CLP	$65.79	$8.53	1.108	$8.03	$82.35	$3.97	$9.58	$2.50	$1.73	$17.78	$100.13

SOURCE: ACIL ALLEN ANALYSIS

A AEMC 2020 RESIDENTIAL ELECTRICITY PRICE TRENDS REPORT

The AEMC's report, *2020 Residential Electricity Price Trends,* was released in December 2020 (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.

— Spot market modelling:
  - 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 about 4,000 MW of renewable capacity between now and 2021-22, as well as changes in underlying costs). AEMC acknowledges that bidding behaviour may change in the future and therefore affect their results. In our analysis for 2021-22 we use our December 2020 Reference case projection settings which are closely aligned with AEMO's 2020 ISP and 2020 ESOO.
  - The projected time of day spot price outcomes presented in the AEMC report appear to be relatively similar to those developed by ACIL Allen as shown in Figure A.1. However, there are some differences, most notably the AEMC appears not to project prices as low as ACIL Allen during daylight hours in South Australia. Our modelling suggests that the continued uptake of rooftop PV and the committed development of utility scale solar will drive down prices during

daylight hours in South Australia such that on average they will tend to be negative. This has already started to occur over the last few months of 2020 and January 2021.

FIGURE A.1 PROJECTED AVERAGE TIME OF DAY SPOT PRICE ($/MWH, NOMINAL) – 2021-22

Note: AEMC prices inferred from charts in AEMC 2020 Price Trends Report

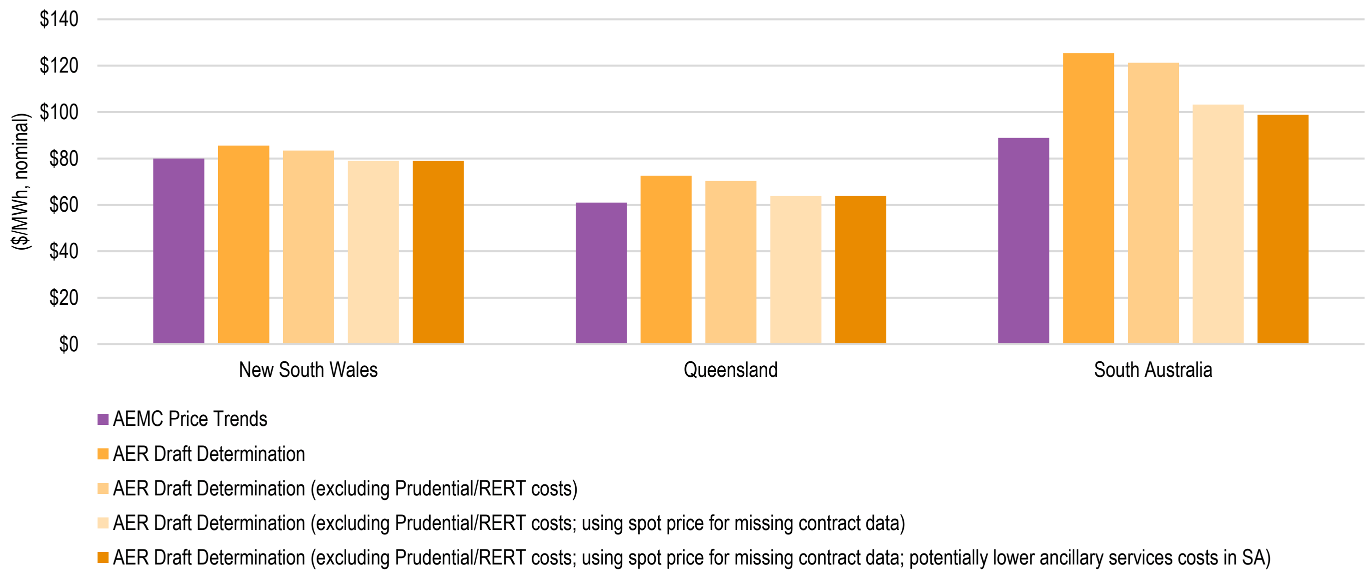
SOURCE: ACIL ALLEN ANALYSIS AND AEMC RESIDENTIAL ELECTRICITY PRICE TRENDS 2020

— Other wholesale costs:
  – ACIL Allen has confirmed with the AEMC that the AEMC wholesale cost estimates exclude prudential and RERT costs. These costs amount to about $2/MWh in New South Wales and Queensland, and about $4/MWh in South Australia (after accounting for losses).
— Hedge portfolio:
  – 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.
— Hedge or contract prices:
  – AEMC use a 2-year build-up of hedges using ASX Energy contract price data up to 2 November 2020.
  – It appears AEMC's portfolio build-up is assumed to be completed by April 2021, as will ACIL Allen's for the Final Determination (for the Draft Determination we end the book build as 5 January 2021).
  – This means that five months of actual ASX Energy prices are unable to be included in the AEMC analysis for 2021-22 (with the five-month period being November 2020 to end of March 2021).
  – 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 five 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 2021-22, AEMC is missing at least, an assumed, 55 per cent of ASX Energy trade volumes and corresponding prices, and is using their modelled spot prices to represent the missing 55 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 noted in our methodology report for DMO 2 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 using the AEMC's approach.
- 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 at the end of March 2021 for the Final Determination, whereas AEMC had to make their final estimates at the beginning of November 2020 (so in effect the AEMC has had to fill in a contract price and volume data gap of five 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 and April 2021 – instead we simply close the contract data as of 5 January 2021.
- The projected wholesale costs presented in the AEMC report for 2021-22 are lower than those of this Draft Determination – particularly for South Australia. This is mainly a result of the difference in the hedge book build approach. As a sensitivity, ACIL Allen has adopted the AEMC approach by using our projected spot prices to inform what the contract prices might be for the next five months. Figure A.2 shows that by doing this there is much better agreement in the estimated wholesale costs.
- There remains some difference in the wholesale cost estimates in South Australia, but these are likely to be explained by a difference in approach to estimating the ancillary services costs. AEMC appear to forecast these costs via a trend analysis and remove price spikes (such as those that occurred in January – February 2020). As noted in section 4.4.2, providing there are no islanding events between this Draft Determination and the Final Determination in South Australia, ACIL Allen's estimates of the ancillary service costs will likely decrease in South Australia for the Final Determination by about $4/MWh.
- Taking these factors into account our estimates of the total wholesale costs are within five per cent of the AEMC estimates for New South Wales and Queensland, and within 10 per cent for South Australia, as shown in Figure A.2.

FIGURE A.2 TOTAL WHOLESALE COSTS ($/MWH, NOMINAL) – 2021-22



SOURCE: ACIL ALLEN ANALYSIS AND AEMC

- The different spot price projections or assumptions on the uptake of rooftop PV (which effects the shape of the NSLP) – particularly during daylight hours for South Australia will largely explain the remaining difference between the estimated total wholesale costs. The lower spot prices during daylight hours projected by ACIL Allen in South Australia actually increase the cost of hedging, since during these periods, the NSLP load profile will most likely be over hedged at the higher contract price.
- 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 when we update the analysis for the Final Determination. It should also be noted that 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 continue to be traded at volumes observed in previous years, and contract prices decrease further, between this Draft Determination and the Final Determination, then a further decrease in the WECs would be expected for the Final Determination.

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