ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN ENERGY REGULATOR

28 APRIL 2020

DEFAULT MARKET OFFER

ESTIMATING WHOLESALE ENERGY AND ENVIRONMENTAL COSTS

PHASE 2: APPLICATION OF METHODOLOGY FOR 2020-21 FINAL DETERMINATION

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

LEVEL NINE
60 COLLINS STREET
MELBOURNE VIC 3000
AUSTRALIA
T+61 3 8650 6000
F+61 3 9654 6363

LEVEL ONE
50 PITT STREET
SYDNEY NSW 2000
AUSTRALIA
T+61 2 8272 5100
F+61 2 9247 2455

LEVEL FIFTEEN
127 CREEK STREET
BRISBANE QLD 4000
AUSTRALIA
T+61 7 3009 8700
F+61 7 3009 8799

LEVEL ONE
15 LONDON CIRCUIT
CANBERRA ACT 2600
AUSTRALIA
T+61 2 6103 8200
F+61 2 6103 8233

LEVEL TWELVE, BGC CENTRE
28 THE ESPLANADE
PERTH WA 6000
AUSTRALIA
T+61 8 9449 9600
F+61 8 9322 3955

161 WAKEFIELD STREET
ADELAIDE SA 5000
AUSTRALIA
T +61 8 8122 4965

ACILALLEN.COM.AU

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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 2020-21. 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 Final Determination, using the methodology proposed in our Phase 1 methodology report.

In addition, we are required to estimate the same cost components for 2019-20, retrospectively, using the same methodology.

Summary of estimated energy costs

ACIL Allen's estimates of the 2019-20 and 2020-21 total wholesale energy costs, environmental costs and total energy costs (TEC) for the Final Determination for each of the regional tariff profiles for 2019-20 and 2020-21 are presented in Table ES 1 and Table ES 2, respectively.

TABLE ES 1 ESTIMATED ENERGY COST COMPONENTS FOR 2019-20 FINAL DETERMINATION ($/MWH, NOMINAL)

Profile	Total wholesale costs at the customer terminal ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$111.36	$21.68	$133.04
Endeavour - NSLP	$108.61	$21.81	$130.42
Essential - NSLP	$103.17	$21.87	$125.04
Ausgrid - CLP1	$84.15	$21.77	$105.92
Ausgrid - CLP2	$79.64	$21.77	$101.41
Endeavour - CLP	$98.59	$21.81	$120.40
Essential - CLP	$95.11	$21.87	$116.98
Energex - NSLP	$98.34	$20.10	$118.44
Energex – CLP31	$72.52	$20.10	$92.62
Energex – CLP33	$80.97	$20.10	$101.07
SAPN - NSLP	$164.21	$23.72	$187.93
SAPN - CLP	$109.65	$23.72	$133.37

SOURCE: ACIL ALLEN ANALYSIS

TABLE ES 2 ESTIMATED ENERGY COST COMPONENTS FOR 2020-21 FINAL DETERMINATION ($/MWH, NOMINAL)

Profile	Total wholesale costs at the customer terminal ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$111.06	$17.17	$128.23
Endeavour - NSLP	$112.27	$17.36	$129.63
Essential - NSLP	$103.50	$17.25	$120.75
Ausgrid - CLP1	$74.02	$17.22	$91.24
Ausgrid - CLP2	$72.11	$17.22	$89.33
Endeavour - CLP	$103.92	$17.36	$121.28
Essential - CLP	$87.90	$17.25	$105.15
Energex - NSLP	$91.49	$15.10	$106.59
Energex – CLP31	$72.29	$15.10	$87.39
Energex – CLP33	$74.06	$15.10	$89.16
SAPN - NSLP	$154.12	$18.57	$172.69
SAPN - CLP	$93.15	$18.57	$111.72

SOURCE: ACIL ALLEN ANALYSIS

The change, in $/MWh and % terms, in the estimated total energy costs between 2019-20 and 2020-21 are shown in Table ES 3.

TABLE ES 3 CHANGE IN ESTIMATED TOTAL ENERGY COST BETWEEN 2019-20 AND 2020-21 ($/MWH, NOMINAL AND %) - FINAL DETERMINATION

Profile	2019-20 Total energy costs at the customer terminal ($/MWh, nominal)	2020-21 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2019-20 to 2020-21 ($/MWh, nominal)	Change from 2019-20 to 2020-21 (%, nominal)
Ausgrid - NSLP	$133.04	$128.23	($4.81)	-3.62%
Endeavour - NSLP	$130.42	$129.63	($0.79)	-0.61%
Essential - NSLP	$125.04	$120.75	($4.29)	-3.43%
Ausgrid - CLP1	$105.92	$91.24	($14.68)	-13.86%
Ausgrid - CLP2	$101.41	$89.33	($12.08)	-11.91%
Endeavour - CLP	$120.40	$121.28	$0.88	0.73%
Essential - CLP	$116.98	$105.15	($11.83)	-10.11%
Energex - NSLP	$118.44	$106.59	($11.85)	-10.01%
Energex – CLP31	$92.62	$87.39	($5.23)	-5.65%
Energex – CLP33	$101.07	$89.16	($11.91)	-11.78%
SAPN - NSLP	$187.93	$172.69	($15.24)	-8.11%
SAPN - CLP	$133.37	$111.72	($21.65)	-16.23%

SOURCE: ACIL ALLEN ANALYSIS

The change, in % terms, in the estimated energy cost components between 2019-20 and 2020-21 are set out in Table ES 4.

TABLE ES 4 CHANGE IN ESTIMATED ENERGY COST COMPONENTS BETWEEN 2019-20 AND 2020-21 (%) - FINAL DETERMINATION

Profile	Change in total wholesale energy cost (%)	Change in total environmental cost (%)	Change in total energy cost (TEC) (%)
Ausgrid - NSLP	-0.27%	-20.80%	-3.62%
Endeavour - NSLP	3.37%	-20.40%	-0.61%
Essential - NSLP	0.32%	-21.12%	-3.43%
Ausgrid - CLP1	-12.04%	-20.90%	-13.86%
Ausgrid - CLP2	-9.46%	-20.90%	-11.91%
Endeavour - CLP	5.41%	-20.40%	0.73%
Essential - CLP	-7.58%	-21.12%	-10.11%
Energex - NSLP	-6.97%	-24.88%	-10.01%
Energex – CLP31	-0.32%	-24.88%	-5.65%
Energex – CLP33	-8.53%	-24.88%	-11.78%
SAPN - NSLP	-6.14%	-21.71%	-8.11%
SAPN - CLP	-15.05%	-21.71%	-16.23%

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 2019-20, futures base contract prices for 2020-21, on an annualised and trade weighted basis to date, have:
    - decreased by about $5.70/MWh for Queensland

    - decreased by about $5.00/MWh for New South Wales
    - decreased by about $10.30/MWh for South Australia.
  - The market is clearly expecting some softening in price outcomes due to the strong increase in renewable investment coming on-line between 2019-20 and 2020-21. About 5,200 MW of renewable investment will enter the NEM over the next 18 months. Interestingly, cap prices, on a trade weighted basis have decreased marginally on an annual basis between 2019-20 and 2020-21 – suggesting that overall, the market is not expecting the 5,200 MW of additional renewable capacity to increase price volatility.
  - Another driver of lower wholesale electricity prices in 2020-21 is the reduction of gas prices for gas fired generation. Spot prices across the east coast gas market have declined over the past 12 months from levels near, and often above, $10/GJ. 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. LNG producers in Queensland have offered more gas to the domestic market in recent months as a result. With surplus global LNG supply expected to keep international LNG prices lower over the next 12-18 months.
  - The WECs for the New South Wales NSLPs decrease slightly (Ausgrid and Essential) or increase slightly (Endeavour) between 2019-20 and 2020-21. The projected continued uptake of rooftop PV installations for customers in these networks is resulting in the profiles becoming sufficiently peakier so as to increase the cost of hedging the NSLP profiles (all other things equal). Further, the WEC for the Endeavour NSLP increases whereas the WECs for the Ausgrid and Essential NSLPs decrease slightly. Historical data shows the time of day shape of the Endeavour NSLP tends to exhibit a higher degree of volatility which will be influencing the projected WEC estimates.
  - The WECs for the NSLPs in Queensland and South Australia decline between 2019-20 and 2020-21 as a result of stronger declines in contract prices (compared with New South Wales) and less change in the demand profiles since the penetration of rooftop PV is much greater already in these two regions compared with New South Wales.
  - The change in WEC for the CLPs is a mixed result – with some increasing slightly, and others decreasing by 15 per cent between 2019-20 and 2020-21. The change in WEC of the CLPs is reflecting the change in shape of the load profiles. It is worth noting that it is the distribution network service providers more than consumer behaviour that control the shape of the CLPs.
  - **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, which has tripled (or increased by $1.16/MWh) across all regions and tariff types. Higher ancillary service costs are the result of a number of events that occurred over the most recent 12 months including, the unplanned VIC-SA interconnector outage in January 2020, the islanding of South Australia in November 2019, the planned Mortlake-Heywood interconnector outage in September 2019 and the unplanned Basslink outage during August-October 2019.
    The cost variations by region mainly result from the differences in the cost associated with the RERT, which were incurred in South Australia in 2018-19 (included in the 2019-20 DMO) and New South Wales in 2019-20 (included in the 2020-21 DMO). At the time of writing this report for the Final Determination, the costs of the RERT for 2019-20 have been reported by AEMO – which are contained in the RERT Quarterly Report for Q4 2019 and several RERT activation estimates for Q1 2020. Therefore, the RERT costs incurred over summer 2019-20 have been used to estimate RERT costs for the 2020-21 DMO. These costs apply to the New South Wales region. As in the Draft Determination, the RERT costs incurred over summer 2018-19 have been used to estimate RERT costs for the 2019-20 DMO. These costs apply to the South Australian region.
- **Environmental costs:** environmental costs are projected to fall significantly across all regions and tariff types. The decline is primarily driven by a projected 49 per cent (or $4.69/MWh) decline in the cost of the LRET between 2019-20 and 2020-21, as a result of declining LGC forward prices. LGC forward prices have fallen due to the surge in investment in renewables over recent years, with LGC supply outstripping legislated demand in the 2019 compliance year. The cost of SRES is projected to increase by one per cent (or $0.08/MWh), with the expectation that small-scale installations will increase slightly in 2021. 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 2020-21.

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**: Initial scoping and assessment of forecasting options
  – The services in this phase include identifying, scoping and developing a methodology to estimate underlying wholesale and environmental cost inputs to forecast changes in retail electricity costs. The deliverables in this phase formed part of the position paper for the DMO (Position Paper), which was published by the AER in September 2019. Our report for this phase of work is available on the AER's website[1] (and is referred to in this current report as the methodology report).
— **Phase 2**: Estimating the underlying costs to inform the DMO 2020-21 determination
  – The services in this phase include estimating the underlying cost inputs for the DMO determination based on the methodology developed in Phase 1. The deliverables in this phase will form part of draft DMO prices (Draft Determination) and the final DMO prices (Final Determination). This current report presents our analysis and findings for Phase 2.

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 Final Determination, using the methodology proposed in our Phase 1 methodology report.

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 *Draft Determination: Default Market Offer Price 2020-21* (January 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 2019 Residential Electricity Price Trends Report released in December 2019.

[1] https://www.aer.gov.au/system/files/ACIL%20Allen%20Consulting%20-%20DMO%20Estimating%20wholesale%20energy%20and%20environmental%20costs%20%28phase%201%29%20-%2010%20September%202019_0.pdf

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 is as accurate as possible.

ACIL Allen is required to estimate the wholesale energy, environmental, and other energy related costs for 2020-21. In addition, we are required to estimate the same cost components for 2019-20. The same methodology is used for both years to maintain internal consistency between the two sets of estimates, which allows the AER to consider, if required, percentage changes in each of the cost components. Importantly, we are to estimate the cost components for 2019-20 retrospectively, as if we were undertaking the exercise for 2019-20 in April 2019 for the Final Determination (that is, without the benefit of knowing actual outcomes to date for 2019-20).

2.2 Components of the energy cost estimates

Energy costs comprise:

— wholesale energy costs (WEC) for various demand profiles

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

— National Electricity Market (NEM) fees, ancillary services charges, Reliability and Emergency Reserve Trader costs, and costs of meeting prudential requirements

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

As the energy purchase costs are broader than the wholesale energy and environment costs, we have referred to them as wholesale and environment costs in this report.

2.3 Methodology

The methodology adopted by ACIL Allen is described in detail in Chapter 6 of our methodology report and is summarised below.

The ACIL Allen methodology 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. This includes 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 Wholesale energy costs - 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.

In estimating the wholesale energy costs incurred by a retailer, it is generally assumed that the retailer is partly exposed to the wholesale spot market and partly protected through a contract hedging strategy.

The market-based approach includes an assumed contracting strategy that a prudent retailer would use to manage its electricity market risks or some estimation of contract premiums. Such risks and the strategy used to mitigate them are an important part of electricity retailing.

The WEC for a given year is therefore generally a function of four components:

1. load profile
2. wholesale electricity spot prices
3. forward contract prices
4. contracting 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 value of the generation anticipated at the time of commitment when the investor was faced with a variety of uncertain futures. Once an investment is committed, the costs are sunk. As time proceeds, the value of the generation asset is determined by the actual future that eventuates and may be quite different to the value expected at the time of commitment. 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.

Key steps

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

1. Forecast the half-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 49 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 539[2] (i.e. 49 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 contracting strategy – the contracting 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 539 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

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

The distribution of outcomes produced by the above approach is then analysed to provide a risk assessed estimate of the WEC. 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.

As mentioned above, multiple hedging strategies are tested by varying the mix of base/peak/cap contracts for each quarter. We select a strategy that is robust and plausible for each load profile, 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.

[2] For 2019-20 there are 48 weather influenced simulations and 11 availability simulations – giving a total of 428 simulations.

The hedging strategy for each contract product that results in the lowest 95th percentile annual WEC for 2019-20 and 2020-21 is adopted. 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 2020-21 peak demand and energy forecasts for the regional demand profiles are referenced to the neutral scenarios from the Electricity Statement of Opportunities (ESOO) published by AEMO in August 2019 (and the 2018 ESOO for 2019-20) 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 peak load, and energy forecasts from the AEMO neutral scenario to produce multiple simulated representations of the half hourly load profile for the given determination year using a Monte Carlo analysis. These multiple simulations will 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 49 years of weather data and uses a matching algorithm to produce 49 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 four years to represent a given day in the past.
- The set of 49 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 49 simulations equals the energy forecast, and the distribution of annual peak loads across the 49 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 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 49 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 49 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 2020-21 we have used our September 2019 Reference case projection settings which are closely aligned with AEMO's Integrated System Plan (ISP). For the 2019-20 estimates we have used our March 2019 Reference case (since we are completing the 2019-20 analysis retrospectively at the time of the Final Determination for 2019-20).

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

Table 2.1 provides a summary of the assumed changes to existing supply included in the 2020-21 market simulations.

TABLE 2.1 CHANGES TO EXISTING SUPPLY

Project name	Generation technology	Capacity (MW)	Region	Nature and date of change
Gladstone	Black coal steam turbine	1,680	QLD	Five units in operation and one off-line
Torrens Island A	Natural gas steam turbine	480	SA	Gradual closure from Q4 2020 to Q4 2022
Liddell	Black coal steam turbine	2,000	NSW	Three units in operation and one off-line; Retires Q2 2023
Bayswater	Black coal steam turbine	2,740	NSW	25 MW upgrade to each of the 4 units, works beginning 2019 ending 2022
Mt Piper	Black coal steam turbine	1,400	NSW	30 MW upgrade to each of the 2 units, works beginning 2020 and ending 2021
Temporary Generation North and South	Liquid fuelled aero-derivative gas turbines	277	SA	Change of classification from market non-scheduled to market scheduled, to reflect 25- year leases secured by Infigen and Nexif. Assumed to transition to natural gas by 2021
Mackay GT	Liquid fuelled gas turbine	34	QLD	Closes in Q2 2021

SOURCE: ACIL ALLEN ANALYSIS

Table 2.2 provides near term entrants that ACIL Allen considers committed projects for the 2020-21 simulations.

TABLE 2.2 NEAR TERM ADDITION TO SUPPLY

Region	Name	Generation Technology	Capacity (MW)	Expected Entry
NSW1	Bango WF	Wind	244	Q1 2021
NSW1	Bomen Solar Farm	Solar	100	Q1 2021
NSW1	Collector WF	Wind	226.8	Q1 2021
NSW1	Crudine Ridge WF	Wind	135	Q4 2019
NSW1	Darlington Point Solar Farm	Solar	275	Q3 2020
NSW1	Goonumbla Solar Farm	Solar	67	Q4 2020
NSW1	Limondale Solar Farm 1	Solar	220	Q1 2020
NSW1	Limondale Solar Farm 2	Solar	29	Q2 2020
NSW1	Nevertire Solar Farm	Solar	105	Q1 2020
NSW1	Sunraysia Solar Farm	Solar	200	Q1 2020
NSW1	Wyalong Solar Farm	Solar	70	Q3 2020

Region	Name	Generation Technology	Capacity (MW)	Expected Entry
QLD1	Brigalow Solar Farm	Solar	34.5	Q3 2020
QLD1	Chinchilla Solar Farm	Solar	100	Q3 2020
QLD1	Kennedy Energy Park	Battery - Discharge	2	Q1 2020
QLD1	Kennedy Energy Park	Solar	15	Q1 2020
QLD1	Kennedy Energy Park	Wind	43	Q1 2020
QLD1	Kidston Pumped Hydro	Pump - Discharge	250	Q3 2023
QLD1	Oakey Solar Farm Stage 2	Solar	55	Q4 2019
QLD1	Teebar Solar Farm	Solar	52.5	Q3 2020
QLD1	Warwick Solar Farm	Solar	64	Q2 2020
QLD1	Yarranlea Solar Farm	Solar	102.5	Q1 2020
SA1	Barker Inlet	Natural gas	52.5	Q4 2019
SA1	Hallett Aeroderivative GT	Natural gas	27.5	Q1 2020
SA1	Lake Bonney Battery	Battery - Discharge	25	Q4 2019
SA1	Lincoln Gap WF Stage 2	Wind	86	Q4 2020
TAS1	Granville Harbour WF	Wind	112	Q3 2019
TAS1	Wild Cattle Hill WF	Wind	144	Q2 2020
VIC1	Berrybank WF	Wind	180	Q1 2020
VIC1	Bulgana Power Hub	Battery - Discharge	20	Q4 2019
VIC1	Bulgana Power Hub	Wind	194	Q4 2019
VIC1	Carwarp Solar Farm	Solar	99	Q4 2020
VIC1	Cherry Tree WF	Wind	57.6	Q2 2020
VIC1	Cohuna Solar Farm	Solar	27.27	Q4 2020
VIC1	Dundonnell WF	Wind	336	Q2 2020
VIC1	Elaine WF	Wind	86	Q3 2020
VIC1	Kiamal Solar Farm	Solar	200	Q2 2020
VIC1	Moorabool WF	Wind	312	Q4 2019
VIC1	Mortlake South WF	Wind	157.5	Q4 2020
VIC1	Stockyard Hill WF	Wind	530	Q1 2020
VIC1	Winton Solar Farm	Solar	85	Q4 2020
VIC1	Yatpool Solar Farm	Solar	81	Q2 2020

Note: Renewable plant are assumed to come online progressively in stages, as are coal plant upgrades. The date of expected entry of a plant's capacity represents the entry of its first stage.

SOURCE: ACIL ALLEN ANALYSIS

The market modelling also includes the restructure of the Queensland Government's assets and the formation of CleanCo. The CleanCo portfolio includes Wivenhoe pumped storage facility, Swanbank E, Barron Gorge, Kareeya and Koombooloomba power stations. The key impact of CleanCo is the change in operation of Wivenhoe, which operates more aggressively, reflecting its position in the new, smaller portfolio, and thus acting more so as a price taker than a price maker.

The modelling assumes that new renewable projects associated with the Queensland Government's 50 per cent renewable energy policy, including the recently re-activated Renewables 400 reverse auction, will not be commissioned until beyond 30 June 2021.

Similarly, the modelling assumes new renewable projects associated with the Victorian Renewable Energy Target, beyond the winning projects of the first round of the auction process, will not be commissioned until beyond 30 June 2021.

2.3.2 Renewable energy policy costs

Renewable energy scheme (RET)

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. Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2019, 2020 and 2021 calendar years, with the costs averaged to estimate the 2019-20 and 2020-21 financial year costs.[3]

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 2019, 2020 and 2021 from brokers TFS[4]
— the published Renewable Power Percentages (RPPs) for 2019 and 2020 of 18.60 per cent and 19.31 per cent, respectively, as published by the CER (the published RPP for 2020 is used in the 2020-21 estimate only)
— estimated RPP values for 2020 of 19.61 per cent (used in the 2019-20 estimate only) and for 2021 of 19.44 per cent[5]
— the binding Small-scale Technology Percentages (STPs) for 2019 and 2020 of 21.73 per cent and 24.40 per cent, respectively, as published by the CER
— estimated STP value for 2021 of 22.15 per cent[6]
— CER clearing house price[7] for 2020 and 2021 for Small-scale Technology Certificates (STCs) of $40/MWh.

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 2019, 2020 and 2021 of 8.5 per cent, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2019, 2020 and 2021 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.

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.[8]

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[3] Two estimates for 2020 have been presented – one for 2019-20, which is assumed to have been calculated in April 2019, and the other for 2020-21, which is calculated using data up to 25 March 2020.
[4] For 2019-20 and 2020-21, TFS data includes prices up to and including 10 April 2019 and 25 March 2020, respectively.
[5] The estimated RPP values for 2020 and 2021 were estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET targets for 2020 and 2021, respectively.
[6] The STP value for 2021 was estimated using ACIL Allen's estimates of STC creations and liable acquisitions in 2021.
[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.
[8] Table 8.5, page 49 at

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.

In the AEMC's 2019 price trends report[9], the cost of REES appears to be unchanged from the 2018 report.

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.

2.3.3 Other energy costs

Market fees and ancillary services costs

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

Prudential costs

Prudential costs, both AEMO and representing 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.

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 have used the RERT costs as published by AEMO for the 12-month period prior to the determination year. At the time of writing this report for the Final Determination, the costs of the RERT for 2019-20 have been reported by AEMO – which are contained in the RERT Quarterly Report for Q4 2019 and several RERT activation estimates for Q1 2020. Therefore, the RERT costs incurred over summer 2019-20 have been used to estimate RERT costs for the 2020-21 DMO. These costs apply to the New South Wales region. As in the Draft Determination, the RERT costs incurred over summer 2018-19 have been used to estimate RERT costs for the 2019-20 DMO. These costs apply to the South Australian region

We note that the ESC uses this approach in the VDO. However, the ESC expresses the RERT cost on a per customer basis. Instead, 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.

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https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf
[9] Published on 9 December 2019 at: https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2019

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

The MLFs used to estimate losses for 2019-20 are based on the updated draft 2019-20 MLFs published by AEMO on 1 April 2019. The DLFs used to estimate losses for 2019-20 are based on the final DLFs published by AEMO in April 2019.

The MLFs used to estimate losses for the Final Determination for 2020-21 are based on the final 2020-21 MLFs published by AEMO on 1 April 2020. The DLFs used to estimate losses for 2020-21 are based on the final DLFs published by AEMO on 1 April 2020.

2.4 A note on COVID-19

The AER forwarded to ACIL Allen several submissions in relation to COVID-19, which have been reviewed. The methodology has not been changed in response to the COVID-19 outbreak, and nor do we think it should. There are a number of reasons for this:

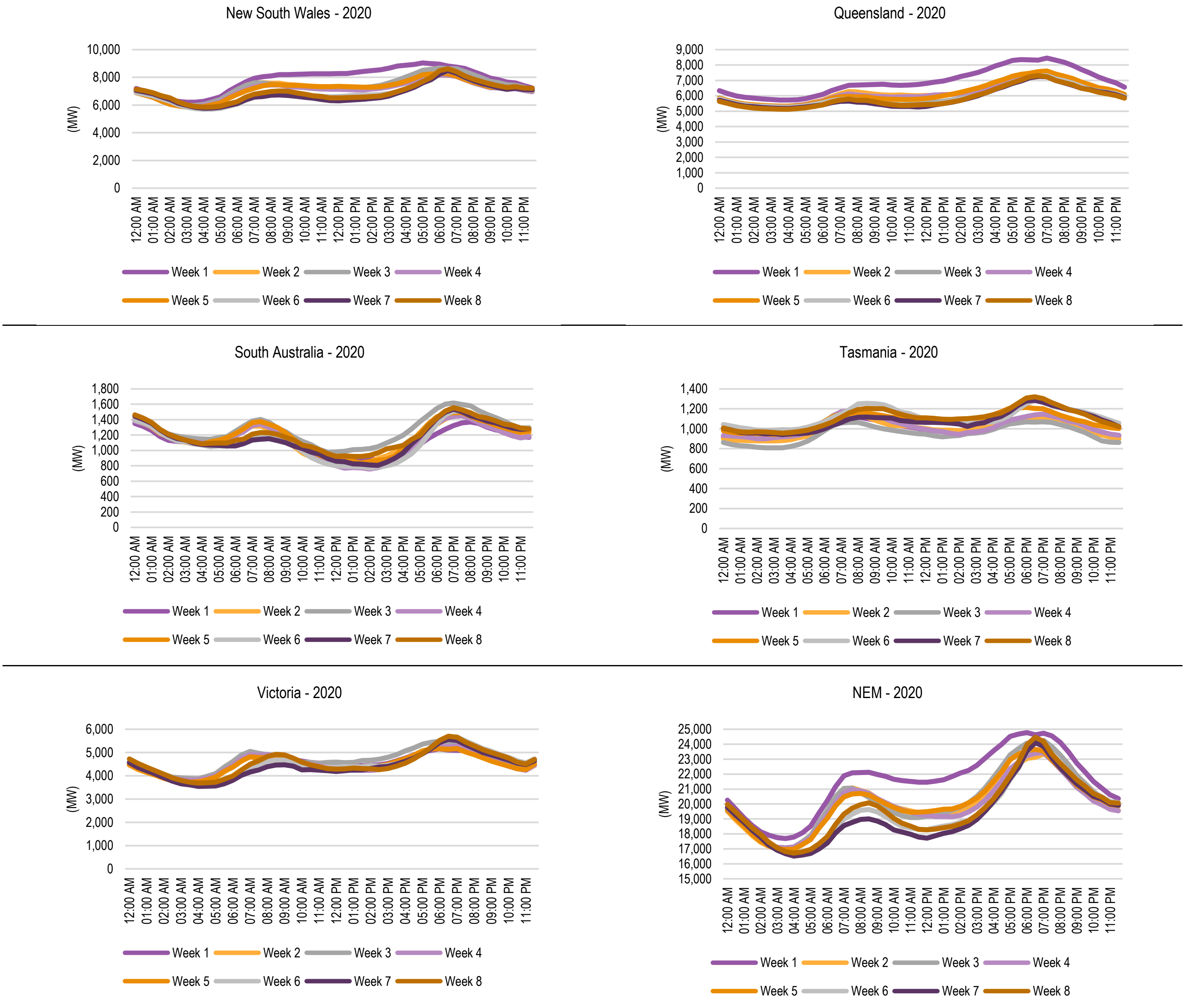
— At this stage it is not possible to quantify the longer-term impact of COVID-19 on the NEM. This will be a function of the policy responses of the federal and state governments – in terms of the extent of the responses and their duration (both during the COVID-19 outbreak, as well as the recovery period after the outbreak).

— To date, there is little robust evidence that the policy responses invoked have had a noticeable change on demand for electricity from the NEM as a whole (this is not to say they will not in the future). Figure 2.1 shows the average time of day demand by week for March and the first 25 days of April 2020 (noting that policy responses have been largely rolled out during the second half of March).
  - There is a step change decline in demand in New South Wales and Queensland from week 1 to week 2 – but this is the result of week 1 being unusually warm (with temperatures about three to four degrees warmer compared with weeks 2 to 5). Tasmania has experienced a decline in temperature in week 5 with temperature dropping about four to five degrees and increasing space heating load. However, there is no discernible change in demand in the second half of March. The charts also show that to date there has been no noticeable change in the shape of the daily demand profile.
  - Further, when comparing Figure 2.1 with Figure 2.2, the variation in average time of day demand across the eight week period is broadly the same in 2020 as it was in 2019.
  - There were further declines in demand in weeks 6 to 7 in 2020 but these are no greater than the declines observed in 2019. Notwithstanding the impacts of weather variations, any change to date in demand due to COVID-19 policies appears to be smaller than the natural underlying week-by-week variation in demand.

— **Figure 2.3** takes the change in temperature into account, and shows the percentage change in weekly average demand since week 2 across the NEM in comparison with the change in temperature – for the same periods in 2020 and 2019:
  - This chart uses the second week of March (Week 2) as the anchor point and plots how average temperature for each week has changed relative to week 2:
    - Average temperature dropped by about 7 to13 per cent in weeks 5 to 7 in 2019 – and this coincides with a drop in demand of about 7 per cent.
    - Average temperature dropped by about 10 to12 per cent in weeks 6 and 7 in 2020 - and this coincides with drop in demand of about 3 to 5 per cent.
    - Directionally, this holds for all period types – except for the morning peak which has experienced the same degree of decline in 2020 and 2019.

- Hence, at this stage, it would be difficult for a statistical model to disentangle the impact of the COVID-19 policies on demand from other factors, such as change in temperature, with any level of confidence.
- There is no doubt that changes to demand have occurred by sector as a result of the COVID-19 response policies.
  - It could be that changes in circumstances to date have largely shifted electricity consumption from usual places of work to the home – despite the loss of employment.
- Further, the closures and reductions in business operations to date appear to be related to services that have low electricity intensity.
- Importantly, the methodology already includes the market's view, to date, of the impact that COVID-19 may have on the NEM which is implicitly taken into account in the contract prices from ASX Energy.
- The methodology uses a large number of simulations which includes variations in demand. Although the variations in demand are driven by weather outcomes in our analysis, they nonetheless cover a large range of demand outcomes and capture the volume risk faced by retailers.
- It is worth noting that if a decline in contract prices was to occur due to lower demand levels, then this does not necessarily result in a decline in WEC. A lower demand (electricity consumption) outcome means that retailers have a smaller base over which they recover their wholesale energy costs – which could negate any decrease in contract prices.

FIGURE 2.1 AVERAGE TIME OF DAY DEMAND (MW) BY REGION AND WEEK – 1 MARCH 2020 TO 25 APRIL 2020



Note: Week 1 = 1-7 March 2020; Week 2 = 8-14 March 2020; Week 3 = 15-21 March 2020; Week 4 = 22-28 March 2020; Week 5 = 29 March – 4 April 2020; Week 6 = 5 – 11 April 2020; Week 7 = 12 – 18 April 2020; Week 7 = 19 – 25 April 2020. Demand reported is scheduled and semi-scheduled generation requirements.

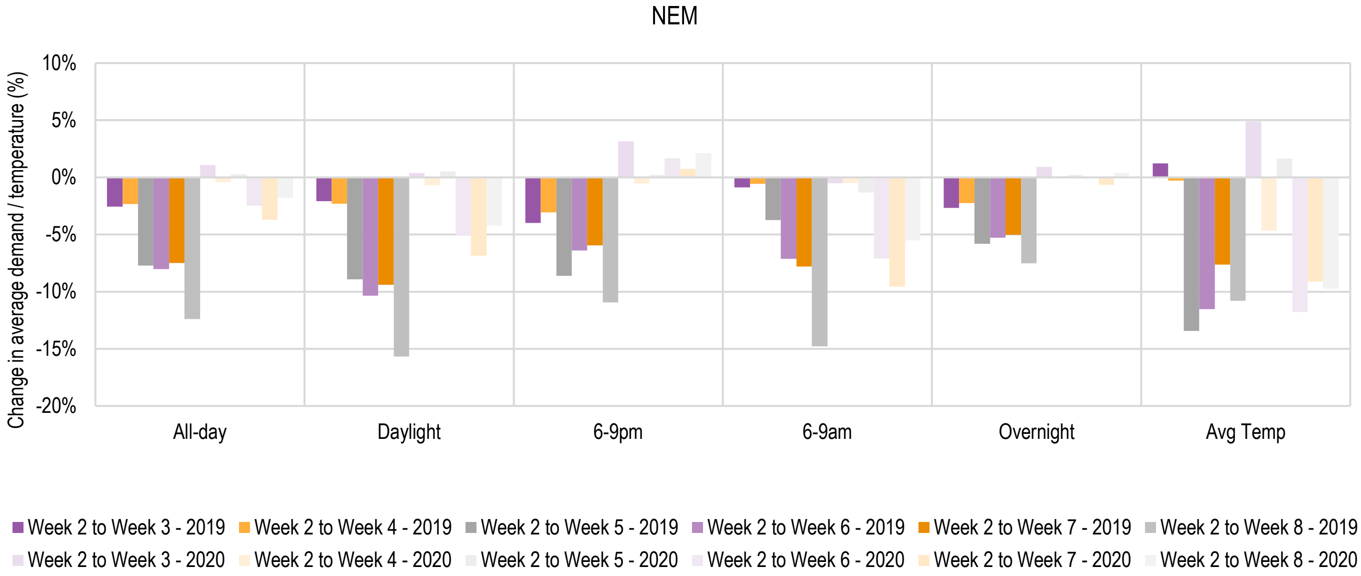
SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 2.2 AVERAGE TIME OF DAY DEMAND (MW) BY REGION AND WEEK – 1 MARCH 2019 TO 25 APRIL 2019

Note: Week 1 = 1-7 March 2019; Week 2 = 8-14 March 2019; Week 3 = 15-21 March 2019; Week 4 = 22-28 March 2019; Week 5 = 29 March – 4 April 2019; Week 6 = 5 – 11 April 2019; Week 7 = 12 – 18 April 2019; Week 7 = 19 – 25 April 2019. Demand reported is scheduled and semi-scheduled generation requirements.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 2.3 CHANGE IN NEM WEEKLY AVERAGE TEMPERATURE AND DEMAND FROM 8-14 MARCH – 2019 AND 2020



Note: Week 1 = 1-7 March 2019; Week 2 = 8-14 March 2019; Week 3 = 15-21 March 2019; Week 4 = 22-28 March 2019; Week 5 = 29 March – 4 April 2019; Week 6 = 5 – 11 April 2019; Week 7 = 12 – 18 April 2019; Week 7 = 19 – 25 April 2019. Demand reported is scheduled and semi-scheduled generation requirements.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO AND BOM DATA

3

RESPONSES TO SUBMISSIONS TO POSITION PAPER

The AER forwarded to ACIL Allen a total of 12 submissions in response to its Draft Determination. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration for the 2020-21 Final Determination. A summary of the review is shown below 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	1st Energy	Nil	Nil	Yes
2	AGL	Nil	Yes	Yes
3	Alinta	Nil	Nil	Nil
4	Australian Energy Council (AEC)	Nil	Yes	Nil
5	Derek Bolton (individual)	Yes	Nil	Nil
6	Energy Australia (EA)	Nil	Yes	Nil
7	Energy Consumers Australia (ECA)	Yes	Nil	Nil
8	Origin	Nil	Yes	Yes
9	Powershop MEA Group	Yes	Yes	Nil
10	Queensland Council of Social Services (QCOSS)	Nil	Nil	Nil
11	Vector Ltd	Nil	Nil	Nil
12	Public Interest Advocacy Centre	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 submissions, stakeholders are generally in agreement with ACIL Allen's proposed market-based approach for estimating the WEC, including the use of the 95th percentile from the 539 simulations as the final estimate.

The submissions raised issues in relation to following sub-components of the wholesale energy cost (WEC):

— Assumptions used in hedge model
— Accounting for uncertainty
— Load profiles
— Provision of detailed data.

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

3.1.1 Assumptions used in the hedge model

Energy Australia on page seven of their submission note:

We expect that consultants' estimates of wholesale costs are highly sensitive to assumptions around how the notional retailer purchases cap contracts. These assumptions typically form part of consultants' proprietary modelling and are not disclosed to stakeholders...

Our methodology is summarised in chapter 2, including the approach used to derive the assumed the level of hedge cover adopted in the analysis, and a more detailed summary is provided in the methodology paper. Further, section 4.2.3 describes the level of hedge cover actually adopted, and the charts in that section visually show the level of hedge cover hour by hour. The hedging strategy chosen minimises the variation in WEC, rather than minimising the value of the WEC. Hence, it can be seen from the charts in section 4.2.3 that the level of hedge cover, and in particular the level of cap contract cover, usually results in what can be described as over-contracting. This is typical of a prudent hedging approach – although it may not be the lowest cost approach, it reduces the variation in the cost of energy under a wide range of simulations.

3.1.2 Accounting for uncertainty

Energy Australia on page seven of their submission note:

We encourage the AER to give appropriate context to the uncertainties involved in estimating wholesale cost trends arising from different methodologies. … any individual forecast can raise expectations that they accurately reflect retailers' actual costs, …

We agree that estimating the WEC inherently involves a degree of uncertainty. This is precisely why the methodology requires that we model a large number of simulations to account for the degree of uncertainty faced by retailers. It is also why we take the 95th percentile estimate from the simulations as the final estimate of the WEC – to minimise the risk of underestimating the true value of the WEC.

3.1.3 Load profiles

Two submissions raised the issue of splitting load profiles and are largely the same issues raised in response to the Position Paper and addressed by ACIL Allen in the Draft Determination.

Derek Bolton raised the issue of households with and without rooftop solar PV having different load profiles, and Powershop on page 1 of its submission notes:

As per our previous submissions, Powershop strongly advises the importance of splitting profiles into residential and business. It is disappointing that the AER chose not to split residential and small business load profiles, citing a lack of smart meter technology in the DMO areas. While, the Consultant may conclude that there are few customers with smart meters, no analysis has been done on the rate of change in the roll-out nor the associated impact on retailer's hedging strategies.

ACIL Allen acknowledges that it is inevitable that different retailers will have different mixes of customers and that different customer types will have different profiles. However, the approach needs to be pragmatic, transparent, consistent, and manageable.

ACIL Allen maintains view that splitting the load into residential and non-residential 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.

3.1.4 Provision of detailed data

Origin Energy in its submission request the hourly data for each of the 539 simulations.

ACIL Allen has made available, and the AER has published, summary data for each of the 539 simulations. In our view this strikes a balance and is sufficient to allow stakeholders to explore and assess the robustness of our analysis.

3.2 Environmental costs

The submissions raised issues in relation to following sub-components of the environmental and other costs:

- Large-scale Renewable Energy Target (LRET)
- Reliability and Emergency Reserve Trader (RERT).

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

3.2.1 LRET

Some stakeholders support the market-based approach used to estimate the cost of LRET. For example, Origin on page 2 of their submission states:

Origin supports the approach applied by ACIL with respect to renewable energy costs.

However, some stakeholders suggest that cost of LRET should be based on the long run cost to retailers rather than the market price of LGCs.

AEC on page two of their submission state:

The AEC notes that ACIL Allen have maintained a market-based approach to calculating retailer costs associated with large-scale generation certificates (LGCs). While we recognise that ACIL Allen sees difficulties in using a contract-based approach, this would better capture the true costs of a representative retailer because it reflects the fact that many retailers procure LGCs through long-term Power Purchase Agreements.

AGL on page three of their submission state:

AGL has covered LRET obligations through long term power purchase agreements (PPAs), as we understand is the case with many retailers. In our view, a prudent retailer will primarily meet its LRET obligation through PPAs as a large retailer would not be able to procure sufficient LGCs from the market to meet its obligation. Consequently, the market price of LGCs does not represent a retailer's cost of actually meeting its LRET obligations.

In their submission, Energy Australia considers that the market-based approach to estimating the cost of LRET has various shortcomings, including that it does not represent retailer practice (on page one of their submission), and that an alternative approach could involve using a sample of PPAs to ascertain the value of an LGC at the time the PPA was struck (on page four of their submission).

ACIL Allen maintains the view that a PPA price reflects the value of generation expected 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.

None of these arguments regarding the estimation of the LGC price are new.

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.

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

ACIL Allen disagrees with Energy Australia's statement that the market based approach does not represent retailer practice – in fact, Tier 2 retailers are typically not in a position to be able to enter into PPAs and make use of other hedging methods, as Powershop asserts on page 2 of their submission to the Draft Determination.

Energy Australia on page three of their submission states:

The number of LGCs traded in the market are a small fraction of those surrendered each year. Methods that infer costs from prices for a relatively small number of LGCs can only provide an accurate estimate of retailer compliance costs by coincidence.

ACIL Allen disagrees with the statement that the number of LGCs traded in the market are a small fraction of those surrendered each year. In fact, 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 latest Quarterly Carbon Market Report[10].

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.

Some stakeholders explore the market-based approach and suggest the use of trade-weighted averages over a longer period of time to estimate the LGC prices.

Powershop on page two of their submission stated:

Tier 2 and smaller retailers will continue to absorb higher Large-scale Generation Certificates (LGC) costs than larger retailers that are able to enter into PPAs and take advantage of other hedging strategies. This is not an acceptable position and Powershop encourage the AER to adopt a greater consideration of environmental hedging timeframes and volumes traded to estimate likely costs rather than using simplistic averages that fall into the favour of retailers who are better resourced and funded. It is likely that LGC prices will continue to decline due to the LRET not just being fully supplied but oversupplied. The decline in price is a function of market conditions – including investments in renewable generation due to the appetite of corporates to enter directly into wind and solar farm PPAs, and some renewable investors willing to take on merchant risk – both of which will contribute further to an oversupply of LGCs.

Despite arguing against the market-based approach, Energy Australia on page six of their submission state:

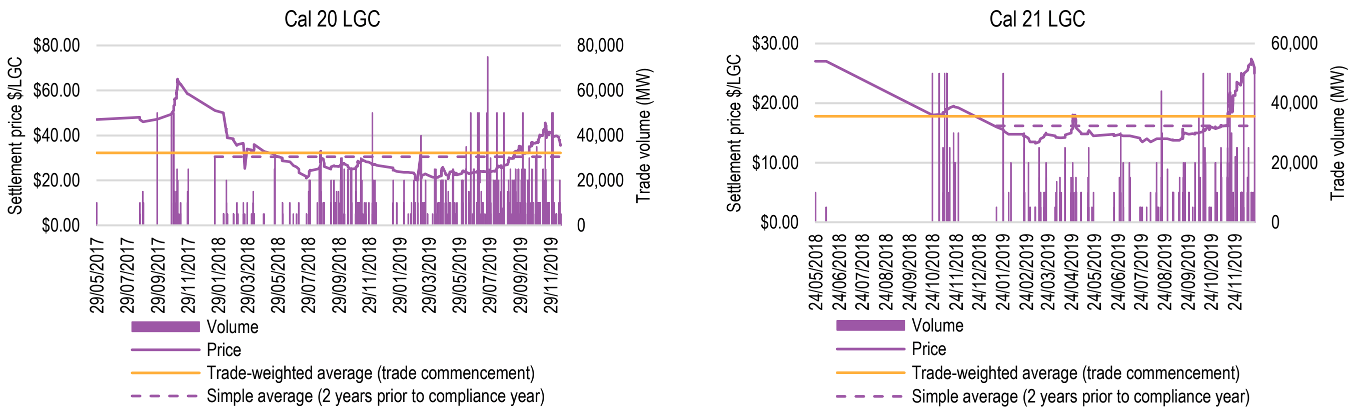
The AER and its consultant may wish to explore the variations possible within the "market-based" approach and justify which set of methods, assumptions or data sources produces accurate estimates of retailer compliance costs in accordance with 16(4)(c)(iii) of the Regulations.

ACIL Allen has investigated an alternative averaging method under the market-based approach to estimating the LGC price. Our original approach, which was used in the Draft Determination, is based on the simple average of LGC prices over the 24 months leading up to the beginning of the compliance year. The alternative approach, which we have adopted in this Final Determination, is based on the trade-weighted average of LGC forward prices since they commenced trading (typically around 2.5 years prior to the beginning of the compliance year).

Figure 3.1 shows the settlement prices and trade volumes for LGC forward contracts for 2020 and 2021 and the corresponding average LGC price under the two methods described above. These comparisons relate to the Draft Determination market data cut-off date of 6 January 2020. The analysis for the Final Determination is shown in Chapter 4 of this report.

[10] CER, Quarterly Carbon Market Report, December Quarter 2019, Figure 15 on page 20.

FIGURE 3.1 LGC FORWARD PRICES ($/LGC), TRADE VOLUMES (NO. OF LGCS) AND AVERAGE LGC PRICES ($/LGC) UNDER TWO AVERAGING METHODS – 2020 AND 2021



SOURCE: TFS, ACIL ALLEN ANALYSIS

For the 2020 and 2021 compliance years and under the Draft Determination market data cut-off date of 6 January 2020, the simple average method results in an LGC price of $30.51 and $16.17, respectively, and the trade-weighted method results in an LGC price of $32.23 and $17.78, respectively. The impact of the trade-weighted method on the Draft Determination approach is an increase in the cost of LRET of $0.33/MWh, as shown in Table 3.2.

As discussed earlier, the trade-weighted averaging method has been adopted for this Final Determination of the 2019-20 DMO and 2020-21 DMO. The LGC prices for the Final Determination using this method are shown in Chapter 4. The trade-weighted averaging method has been used in the Final Determination to reflect the market data available and is consistent with the trade-weighted approach for estimating wholesale electricity contract prices.

TABLE 3.2 COST OF LRET ($/MWH) UNDER TWO METHODS FOR THE DRAFT DETERMINATION 2020-21

	2020	2021	Cost of LRET Draft Determination 2020-21	Change from Draft Determination approach
Simple averaging method				
RPP	19.61%	19.44%		
Average LGC price ($/LGC, nominal)	$30.51	$16.17		
Cost of LRET ($/MWh, nominal)	$5.98	$3.14	$4.56	
Trade-weighted averaging method				
RPP	19.61%	19.44%		
Average LGC price ($/LGC, nominal)	$32.23	$17.78		
Cost of LRET ($/MWh, nominal)	$6.32	$3.46	$4.89	$0.33

SOURCE: TFS, CER, ACIL ALLEN ANALYSIS

3.3 Other costs

3.3.1 RERT

1st Energy on page 1 of their submission state:

…we note that RERT costs attributable to New South Wales RERT events that occurred throughout January 2020 are yet to be included and anticipate this number will be revised with the availability of the market data.

AGL on page 2 of their submission state:

AGL does have some concerns regarding the potential costs of the RERT as well as the cost impact of market directions by the Australian Energy Market Operator (AEMO) on small electricity customers.

However, we agree with ACIL Allen that it is difficult to forecast these costs into the future and the AER's selected methodology of indexing the 2019-20 DMO prices partially mitigates our concerns.

Origin on page 2 of their submission state:

We seek confirmation from the AER that when setting the DMO for 2021-22 it will keep the current RERT value (i.e. $0.63) as the base and it will use the actual 2019-20 value as the estimate for 2021-22. This would ensure a more representative change in the RERT costs and consistency with the index method than if the $0.63 value for 2020-21 is adjusted to reflect more recent actual cost data.

ACIL Allen has used the RERT costs as published by AEMO for the 12-month period prior to the determination year and expressed the cost based on energy consumption. This requires taking the reported cost in dollar terms from AEMO for the given period and prorating the cost across all consumers in the region on a consumption basis.

Therefore, in this Final Determination, for the 2019-20 DMO, we have used the reported RERT costs for 2018-19, and for the 2020-21 DMO, we have used the reported RERT costs for 2019-20.

4 ESTIMATION OF ENERGY COSTS

4.1 Introduction

In this section we apply the methodology described in Section 2 and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the profiles for 2019-20 and 2020-21.

4.1.1 Historic 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 eight years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the profiles.

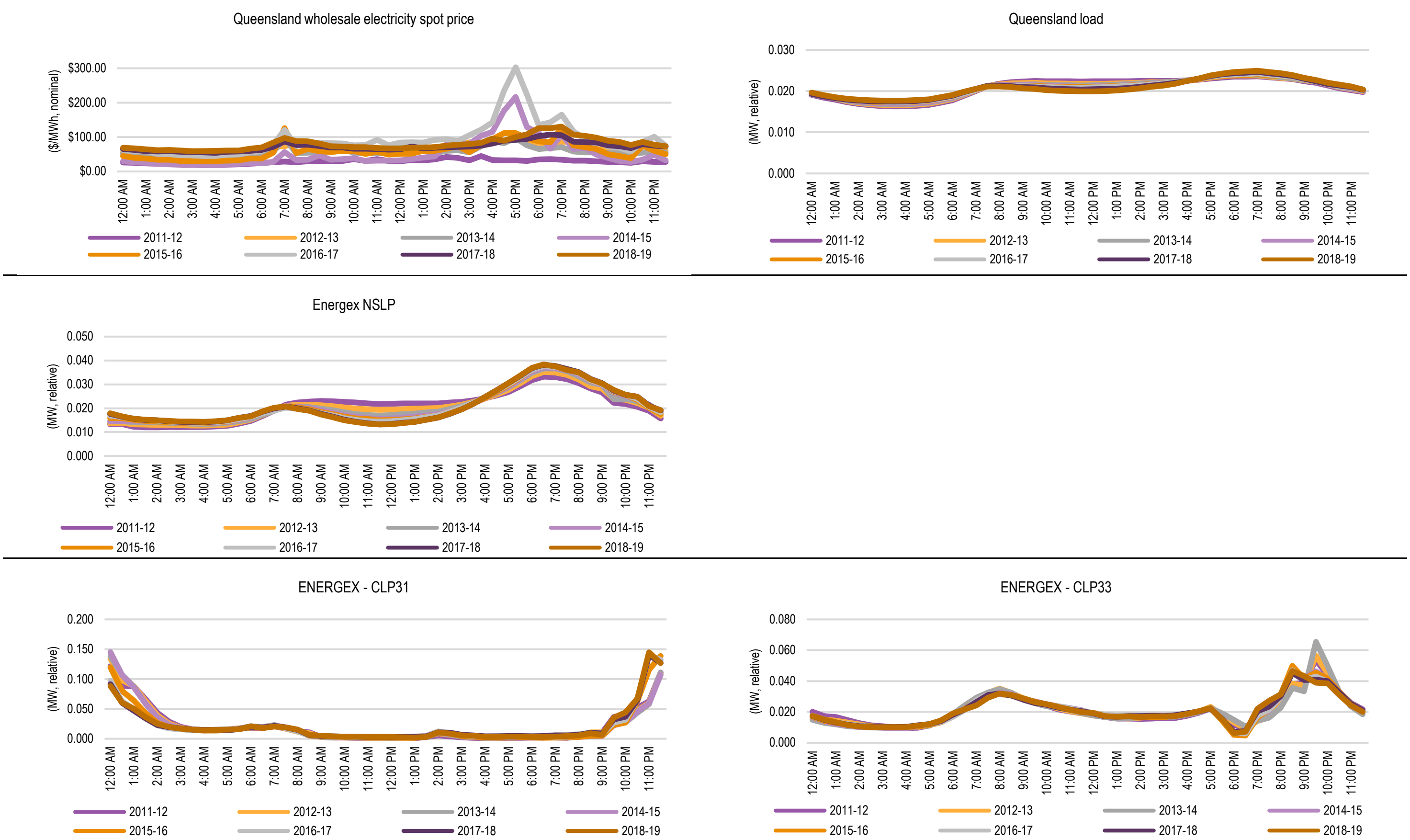
It is worth noting the uplift in spot prices between 2014-15, and 2016-17, across most periods of the day. During this period, wholesale spot prices increased by about $40/MWh in New South Wales and Queensland, and by about $60/MWh in South Australia. This is a result of coal station closures (Wallerawang 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 to date in 2019-20 have decreased by about $15/MWh in New South Wales, decreased by about $10/MWh in New South Wales, and remain reasonably constant 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 (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 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.

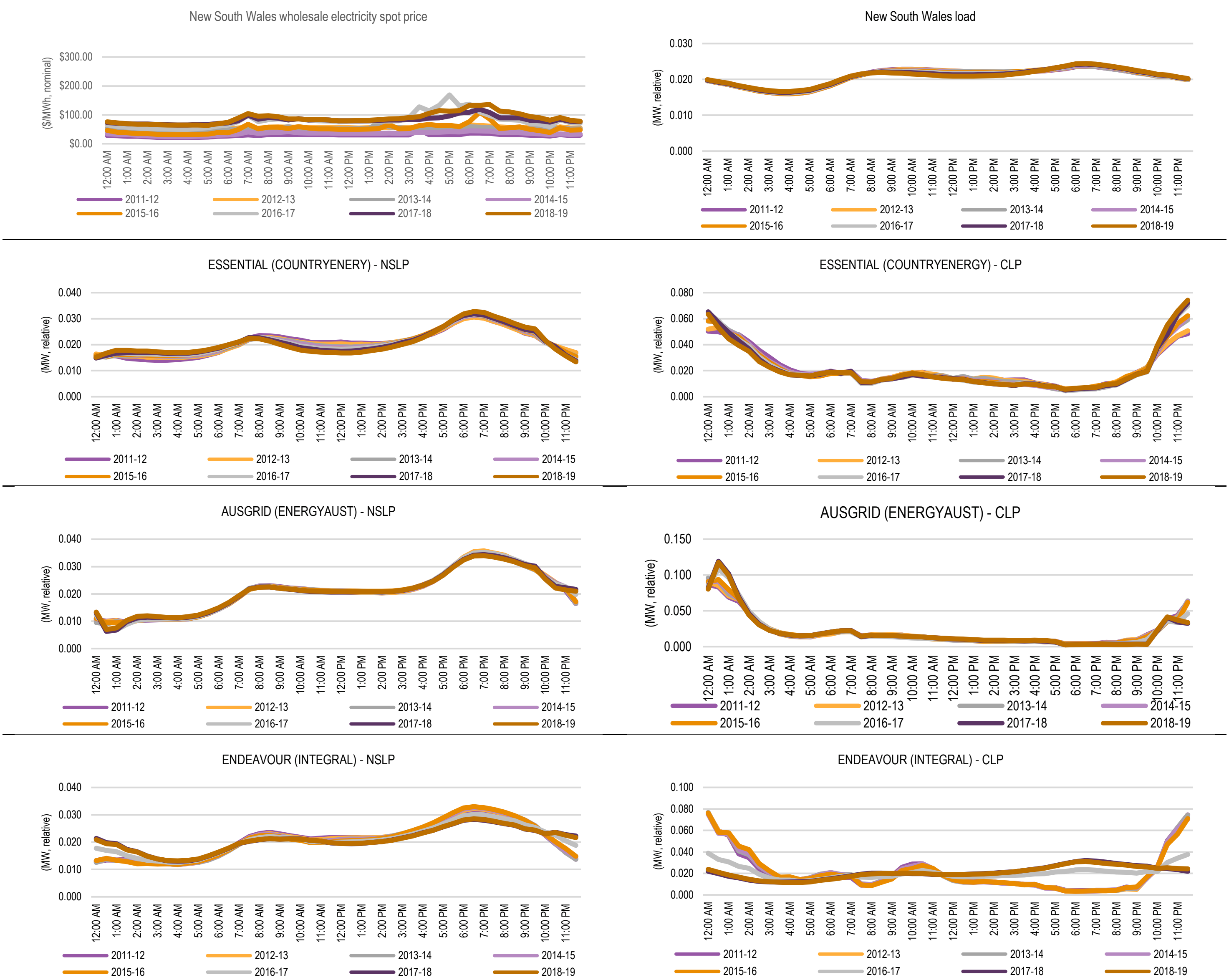
FIGURE 4.1 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – QUEENSLAND – 2011-12 TO 2018-19



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

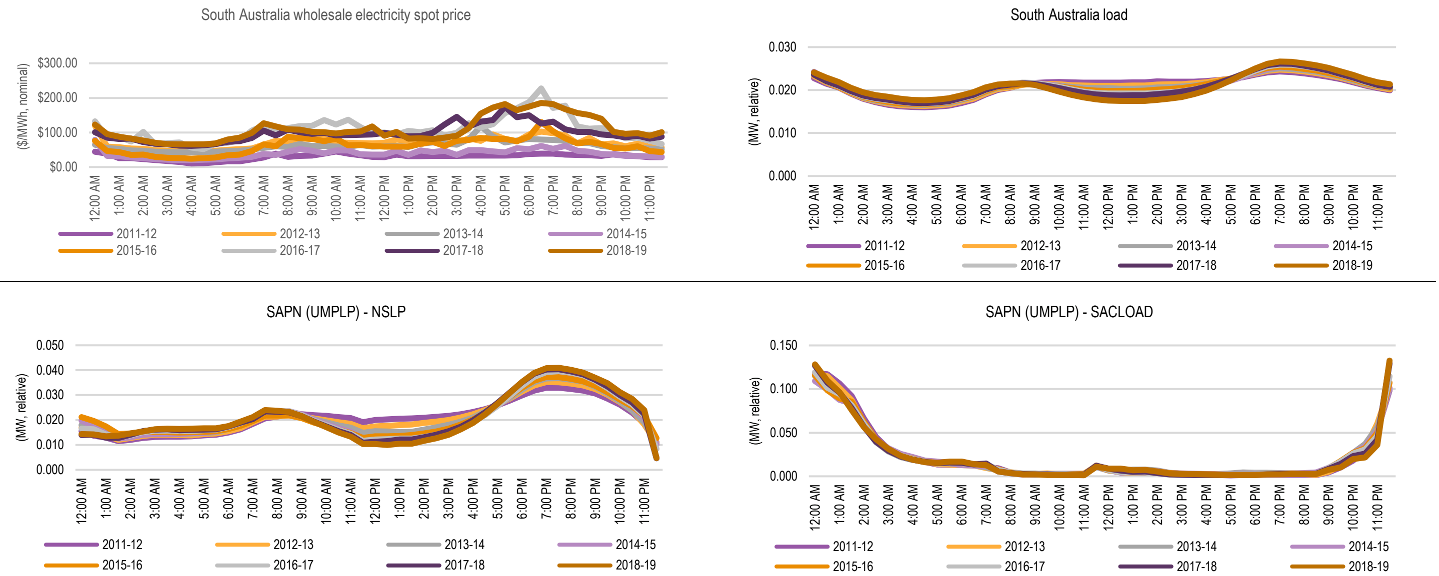
FIGURE 4.2 ACTUAL AVERAGE TIME OF DAY WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – NEW SOUTH WALES – 2011-12 TO 2018-19



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 2018-19



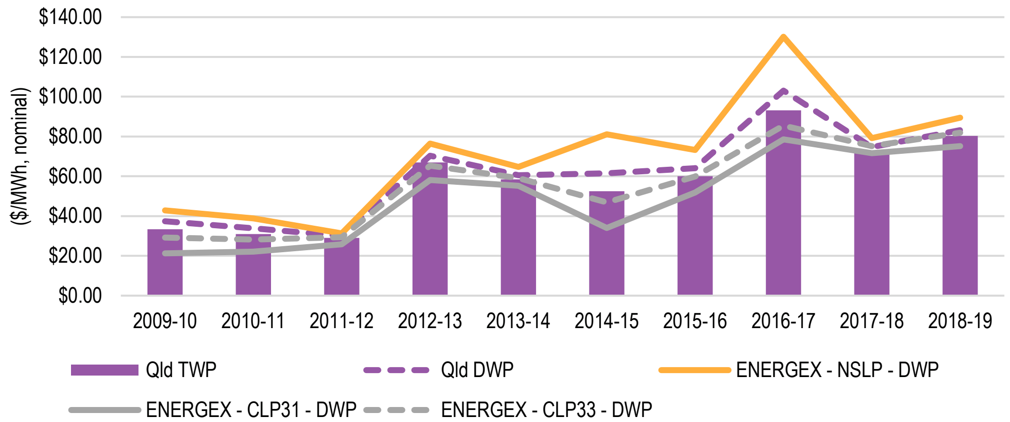
Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of 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 10 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 10 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.

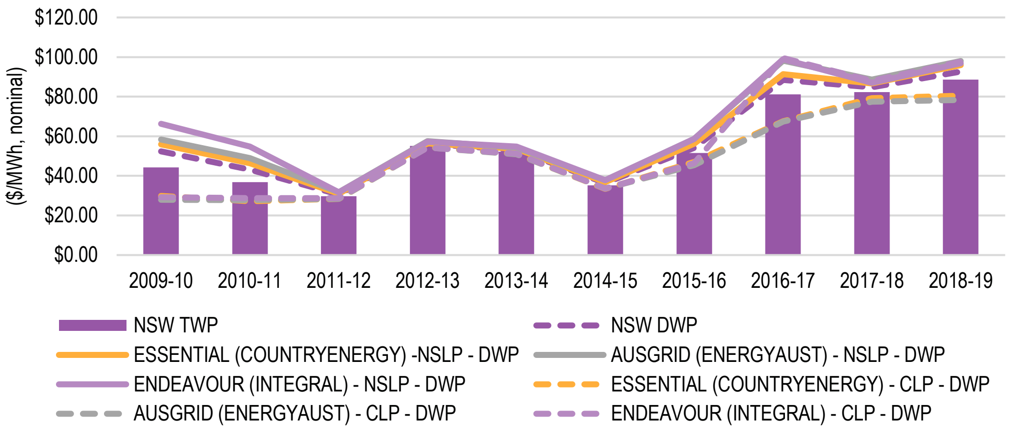
FIGURE 4.4 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY PROFILE AND QUEENSLAND TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

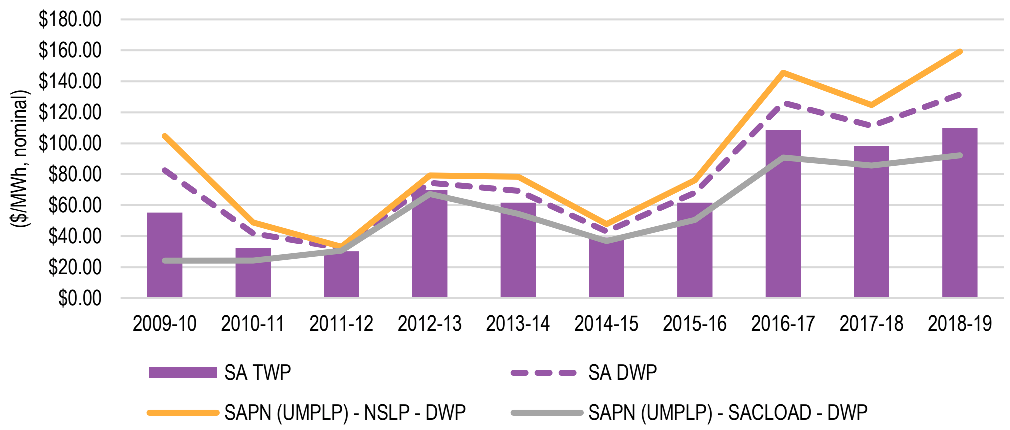
FIGURE 4.5 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY PROFILE AND NEW SOUTH WALES TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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 2018-19



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 movements in contract price is the key contributor to movements in the estimated wholesale energy costs of the different profiles year on year, as is shown in Figure 4.7.

Compared with the 2019-20, futures base contract prices for 2020-21, on an annualised and trade weighted basis to date, have:

— decreased by about $5.70/MWh for Queensland
— decreased by about $5.00/MWh for New South Wales
— decreased by about $10.30/MWh for South Australia.

The market is clearly expecting some softening in price outcomes due to the strong increase in renewable investment coming on-line between 2019-20 and 2020-21. About 5,200 MW of renewable investment will enter the NEM over the next 18 months. Interestingly, cap prices, on a trade weighted basis have decreased marginally on an annual basis between 2019-20 and 2020-21 – suggesting that overall the market is not expecting the 5,200 MW of additional renewable capacity to increase price volatility.

Since the Draft Determination, futures base contract prices for 2020-21, on an annualised and trade weighted basis, have declined by about $3/MWh in New South Wales and South Australia, and $2/MWh in Queensland.

FIGURE 4.7 BASE, PEAK AND CAP CONTRACT PRICES ($/MWH, NOMINAL) – 2019-20 AND 2020-21

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 25 March 2020 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.

Table 4.1 shows the estimated quarterly swap and cap contract prices for 2019-20 and 2020-21.

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

	Q3	Q4	Q1	Q2
		2019-20		
Base	$68.22	$63.79	$80.07	$59.23
Peak	$76.10	$72.08	$106.56	$72.35
Cap	$2.89	$5.01	$14.87	$3.11
		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
		Percentage change from 2019-20 to 2020-21		
Base	-13%	-4%	-7%	-10%
Peak	-10%	-5%	-14%	-16%
Cap	-21%	-26%	-17%	-15%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 10 APRIL 2019 FOR 2019-20, AND UP TO 25 MARCH 2020 FOR 2020-21

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

	Q3	Q4	Q1	Q2
		2019-20		
Base	$80.79	$71.48	$88.22	$72.40
Peak	$94.83	$85.29	$108.40	$78.21
Cap	$6.17	$7.53	$18.44	$6.15
		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
		Percentage change from 2019-20 to 2020-21		
Base	-11%	0%	-3%	-12%
Peak	-16%	-3%	8%	2%
Cap	-29%	-3%	6%	-33%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 10 APRIL 2019 FOR 2019-20, AND UP TO 25 MARCH 2020 FOR 2020-21

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

	Q3	Q4	Q1	Q2
		2019-20		
Base	$87.26	$78.16	$111.89	$73.86
Peak	$108.56	$102.67	$170.00	$98.00
Cap	$6.94	$8.94	$30.18	$7.60

	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
		Percentage change from 2019-20 to 2020-21		
Base	-21%	-11%	-8%	-8%
Peak	-17%	-13%	-26%	-15%
Cap	-27%	-19%	1%	1%

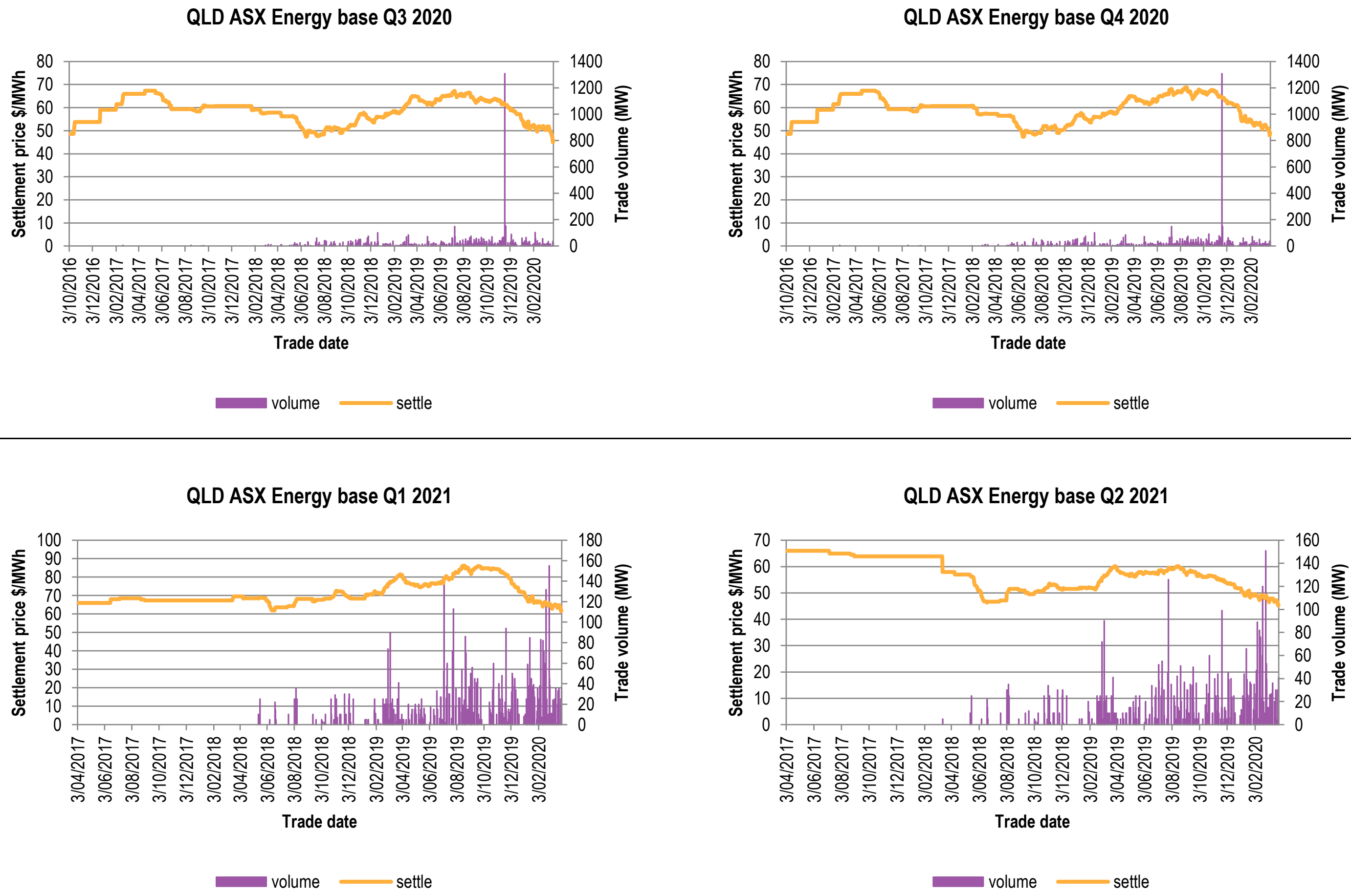
SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 10 APRIL 2019 FOR 2019-20, AND UP TO 25 MARCH 2020 FOR 2020-21

Contract prices decrease from 2019-20 to 2020-21 for all products and quarters in Queensland, although less so for quarter one. In New South Wales, although prices decrease overall, they increase in quarter one, when compared with 2019-20 – with base prices about the same, and cap prices increasing by 6 per cent. Similarly, in South Australia, quarter one prices exhibit the smallest decrease compared with other quarters. However, base contracts decrease for all four quarters in South Australia for 2020-21. It appears the market is of the view that an increase renewable energy penetration, at this stage, will not reduce prices to the same extent in quarter one as in other quarters, or is less certain that prices in quarter one will decrease.

Another driver of lower contract prices in 2020-21 is the reduction of gas prices for gas fired generation. Spot prices across the east coast gas market have declined over the past 12 months from levels near, and often above, $10/GJ. 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. LNG producers in Queensland have offered more gas to the domestic market in recent months as a result. With surplus global LNG supply expected to keep international LNG prices lower over the next 12-18 months

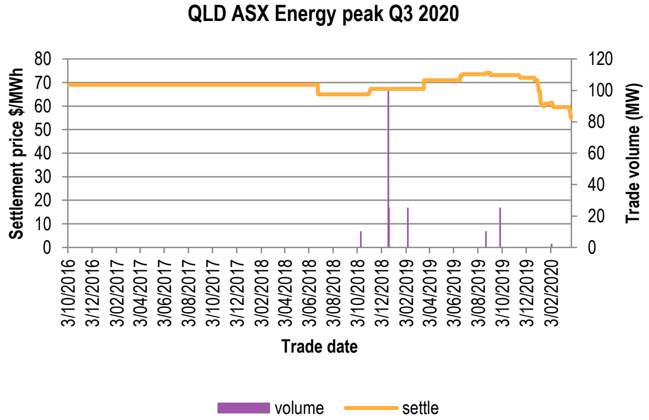
The following charts show daily settlement prices and trade volumes for 2020-21 ASX Energy quarterly base futures, peak futures and cap contracts up to 25 March 2020. It can be seen that the trading of these contracts tends to commence from about June 2018.

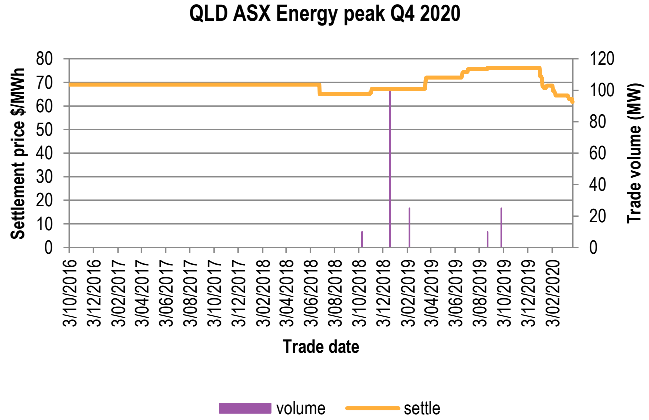
FIGURE 4.8 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES - QUEENSLAND

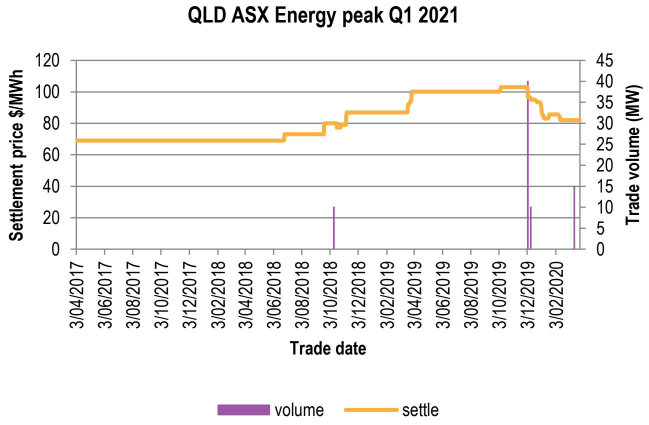


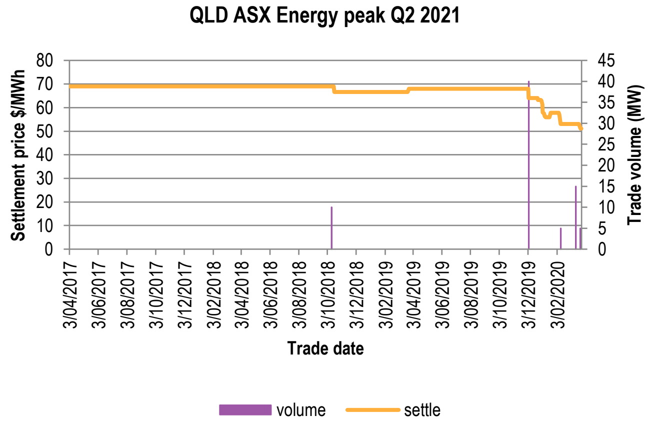
SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

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



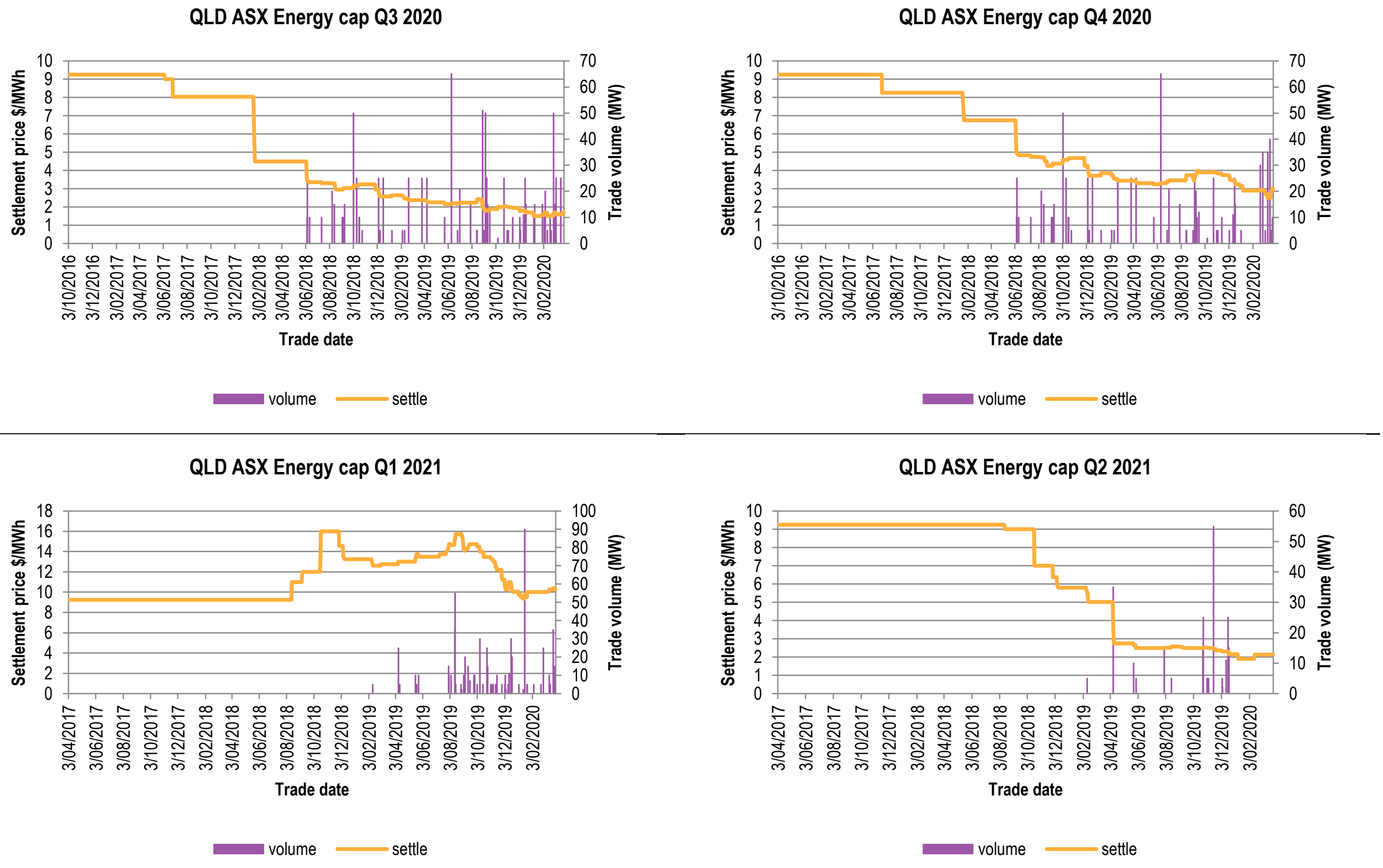






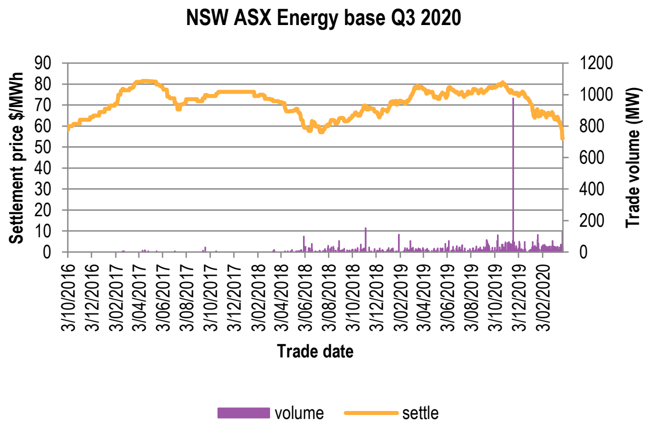
SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

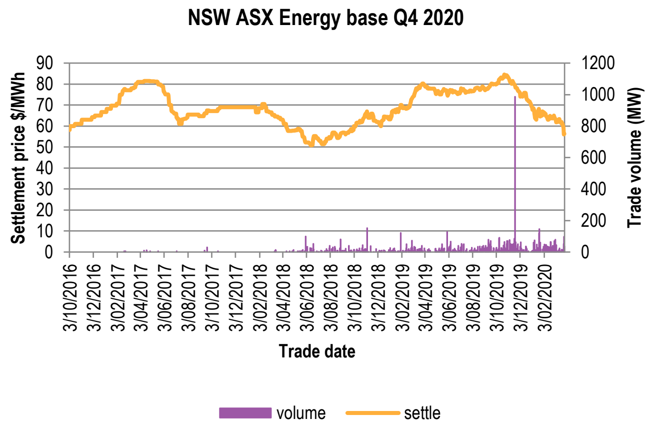
FIGURE 4.10 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS - QUEENSLAND

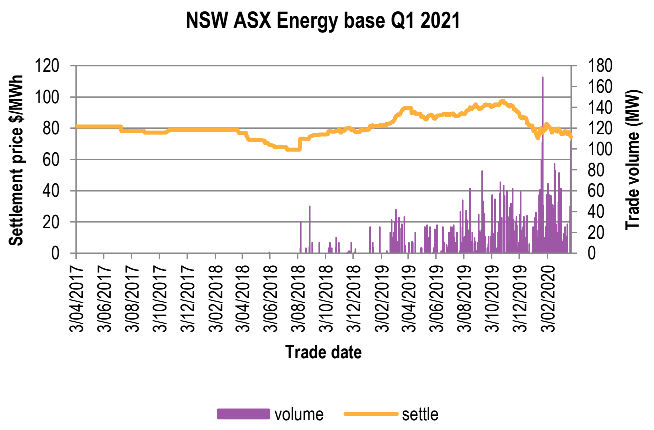


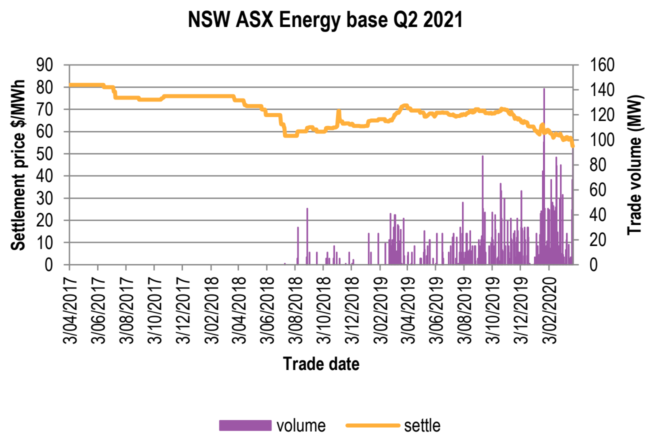
SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

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



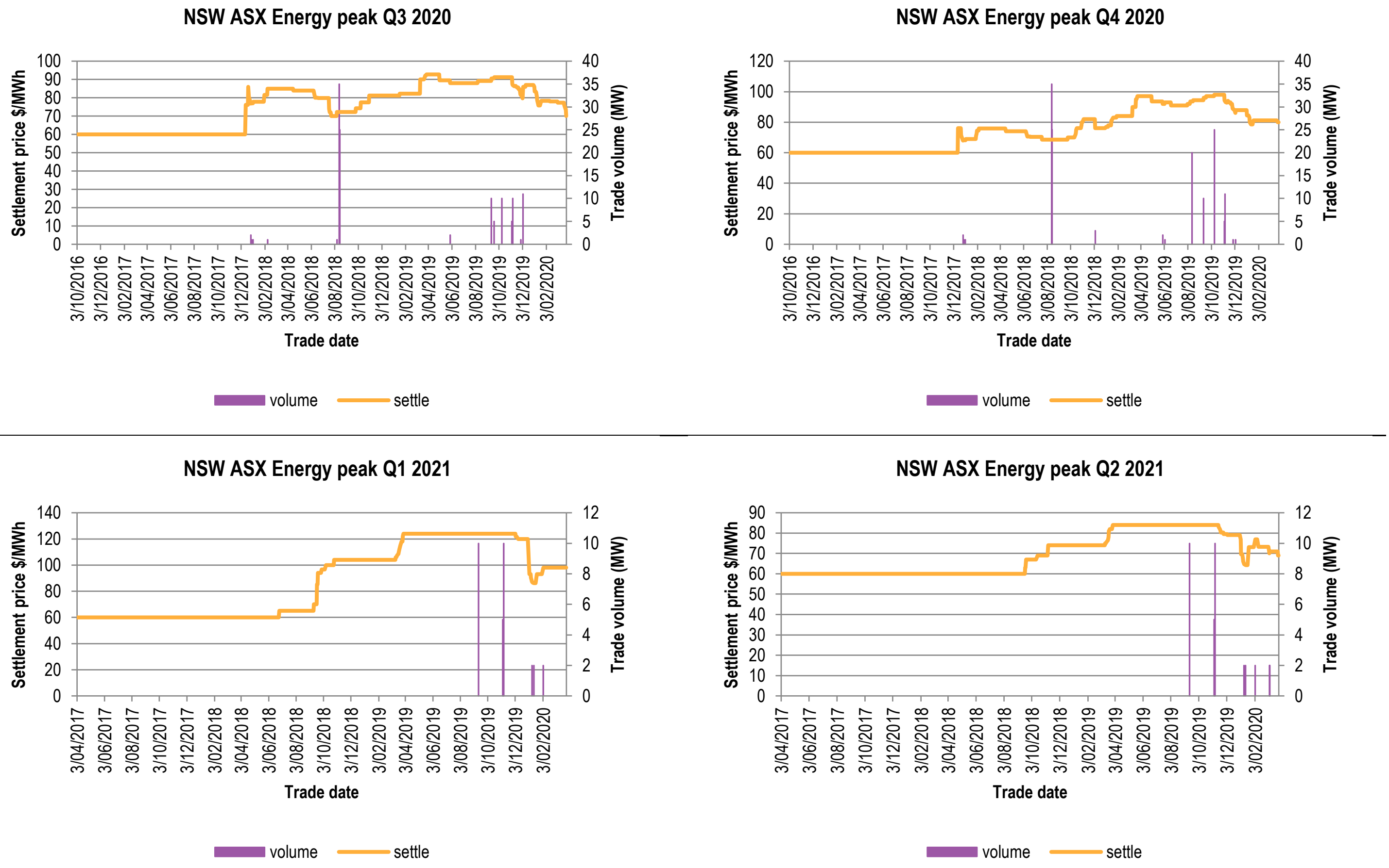






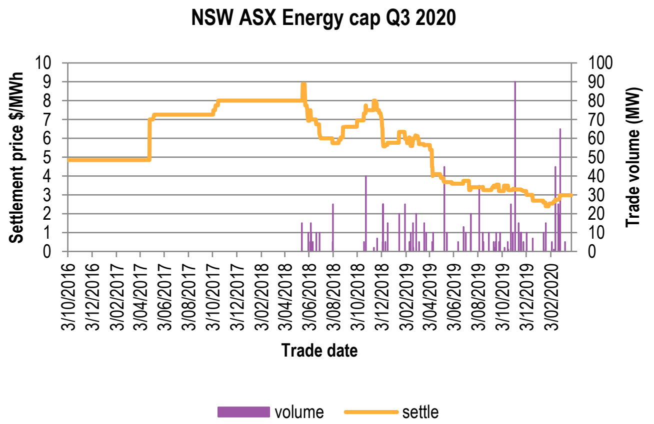
SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

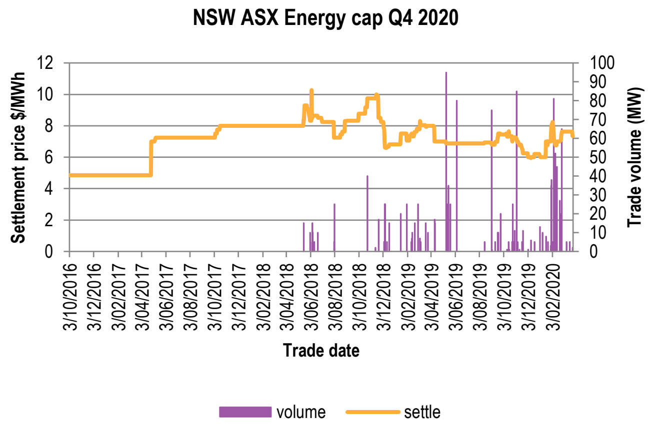
FIGURE 4.12 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY PEAK FUTURES – NEW SOUTH WALES

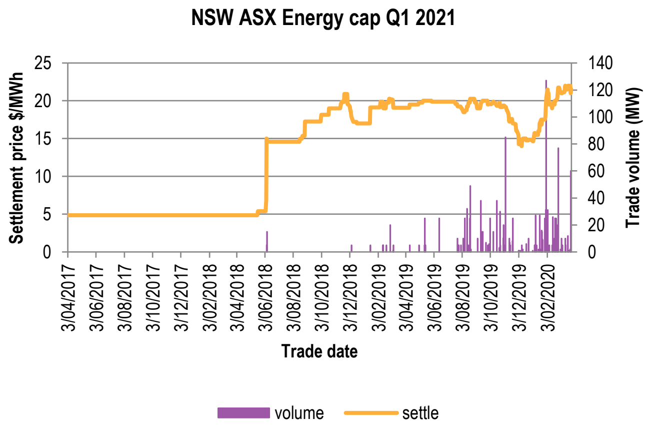


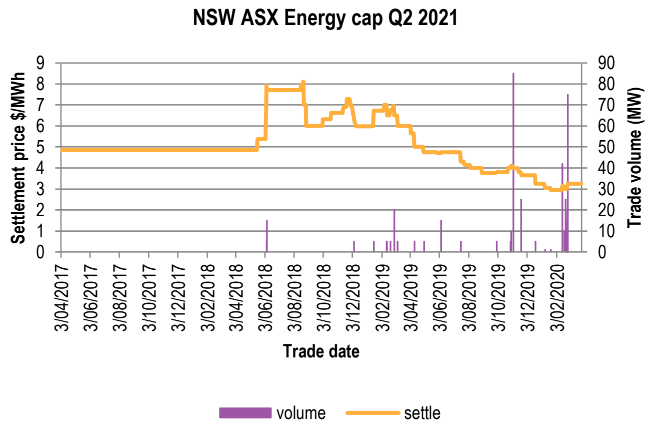
SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

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



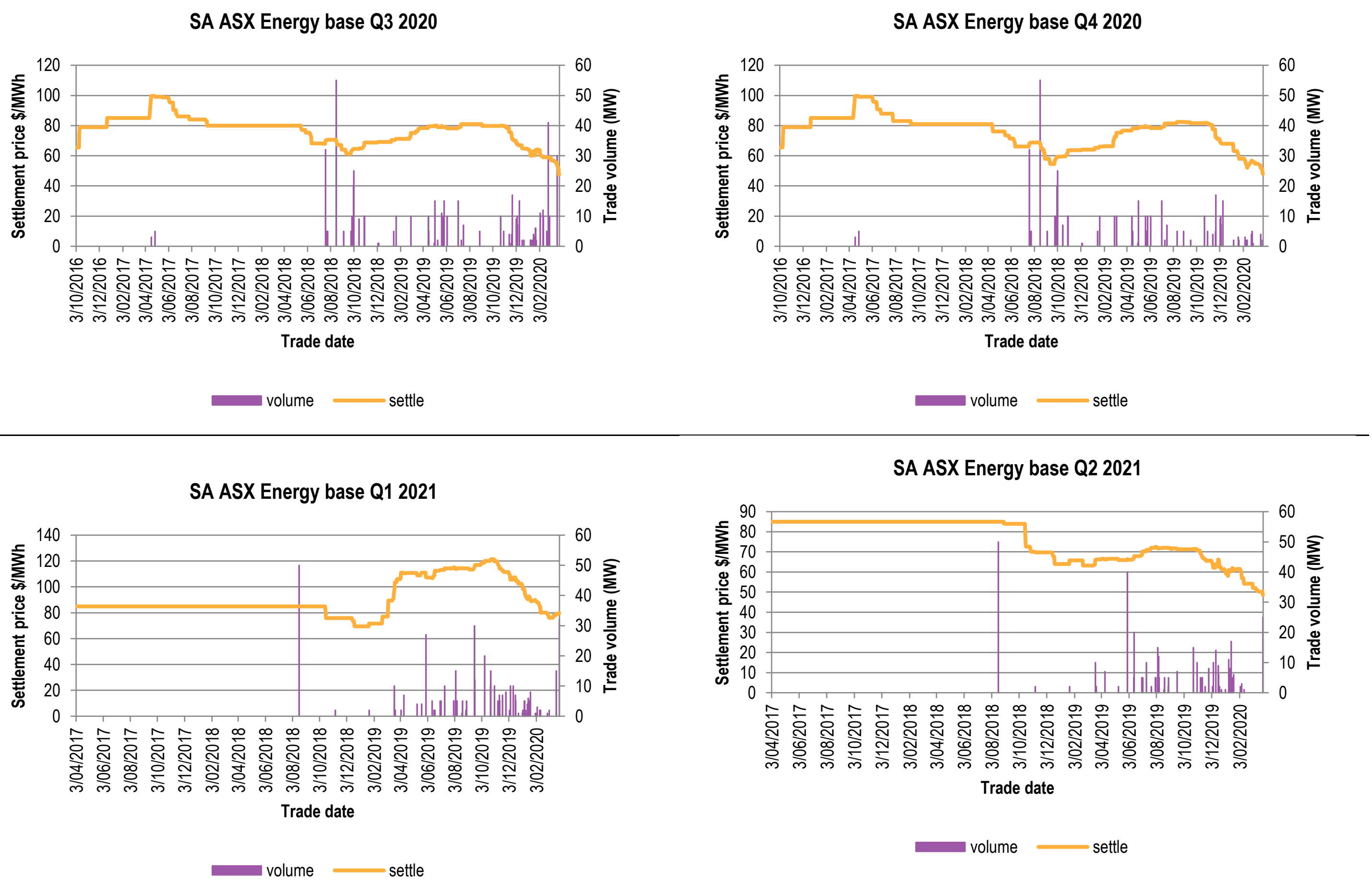






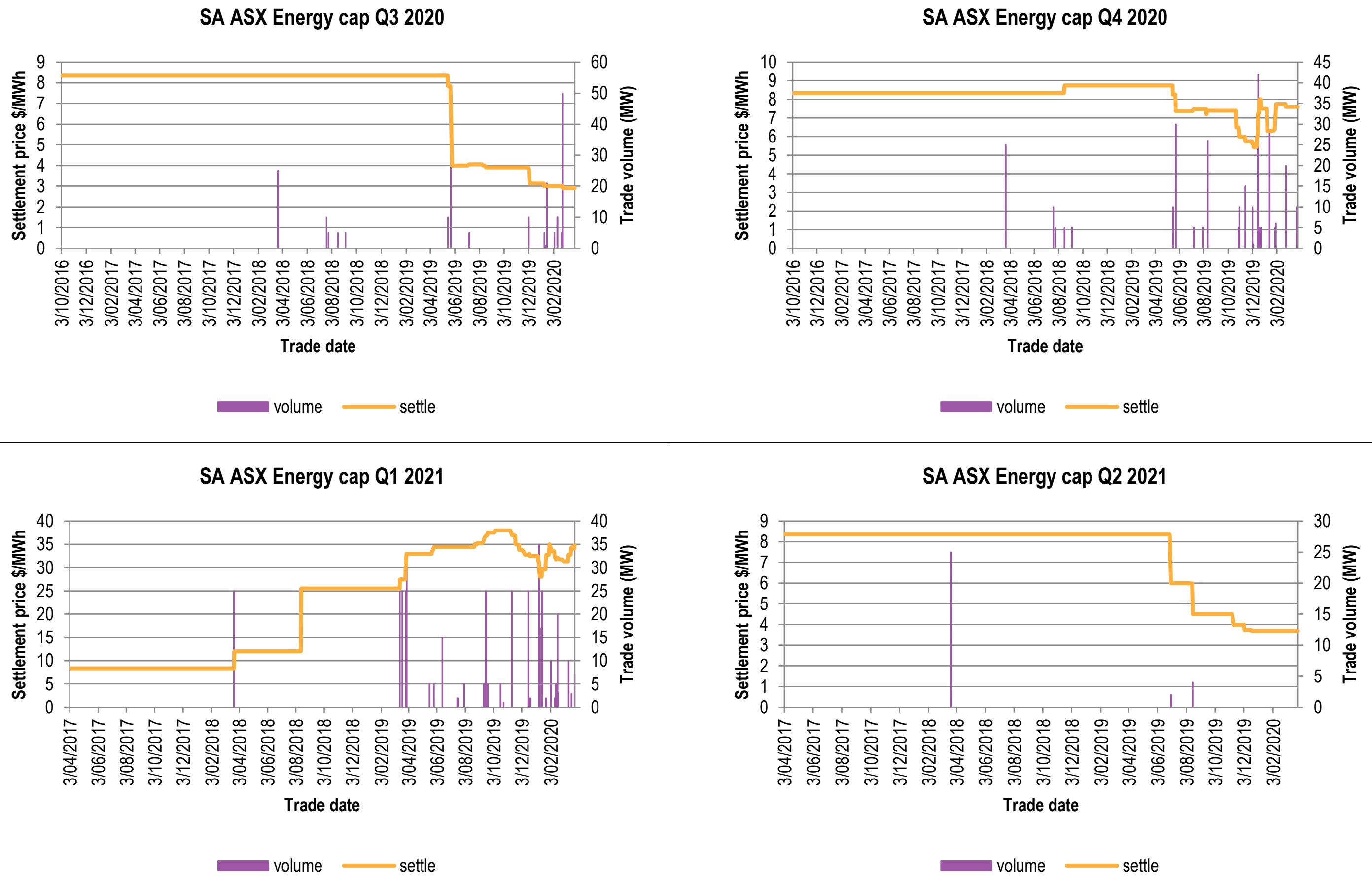
SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

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



SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

FIGURE 4.15 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS – SOUTH AUSTRALIA



SOURCE: ASX ENERGY DATA UP TO 25 MARCH 2020

4.2.2 Estimating wholesale spot prices

ACIL Allen’s proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for the 539 simulations (49 demand and 11 outage sets).

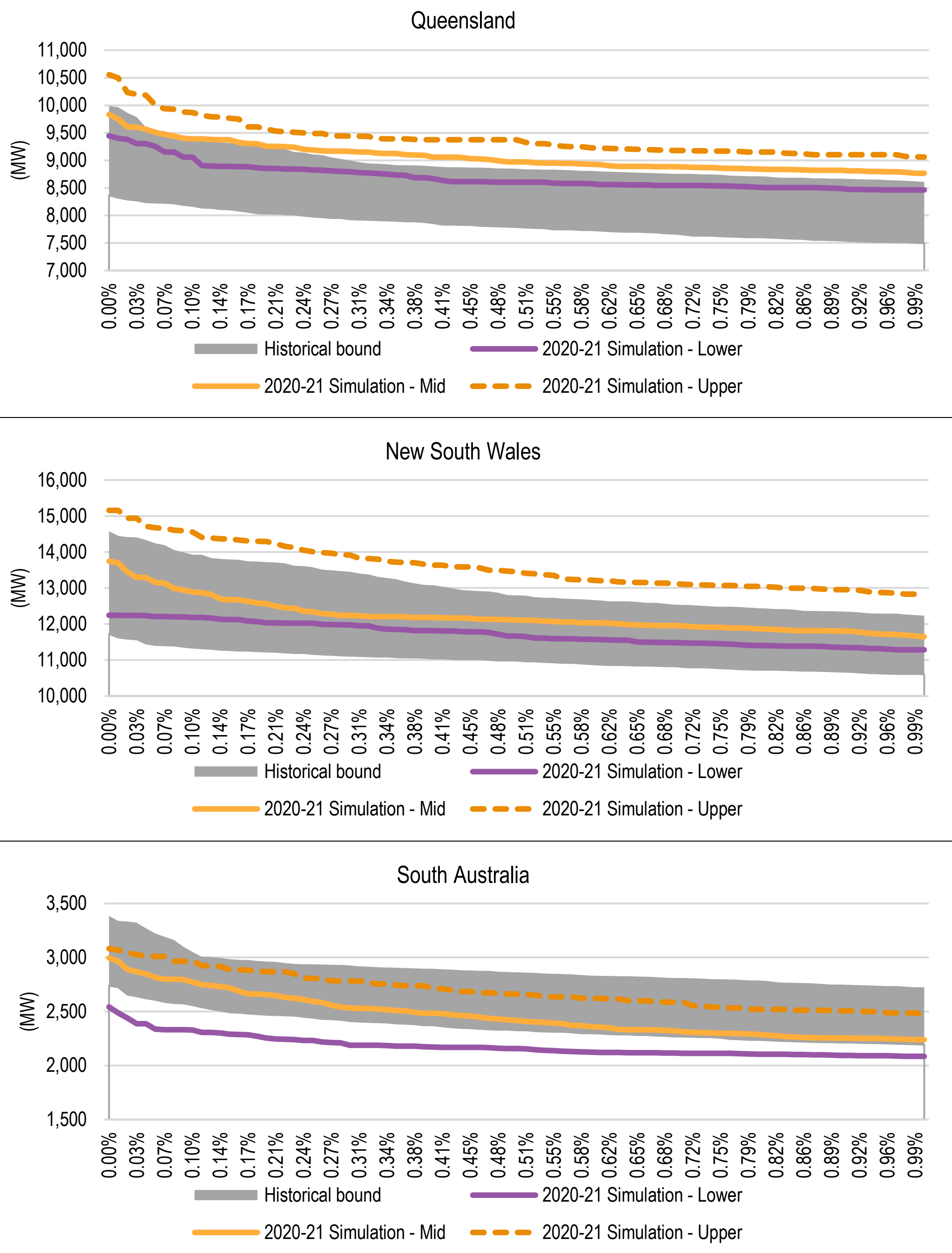
Figure 4.16 shows the range of the upper one percent segment of the demand duration curves for the 49 simulated Queensland, New South Wales and South Australia system demand sets resulting from the methodology for 2020-21, along with the range in historical demands since 2011-12. The simulated demand sets represent the upper, lower and middle of the range of demand duration curves across all 49 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2020-21 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[11]. 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 2020-21 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. What is

[11] The simulated demand sets for 2020-21 are generally higher than the pre-2016-17 observed demand outcomes due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone.

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 4.16 TOP ONE PERCENT HOURLY SYSTEM DEMANDS



SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

Figure 4.17 shows the range of the simulated NSLP demands envelope recent. This variation results in the annual load factor[12] of the 2020-21 simulated demand sets ranging between:

— 26 percent and 35 percent compared with a range of 29 percent to 43 percent for the actual Energex NSLP between 2009-10 and 2018-19 (as shown in Figure 4.18)

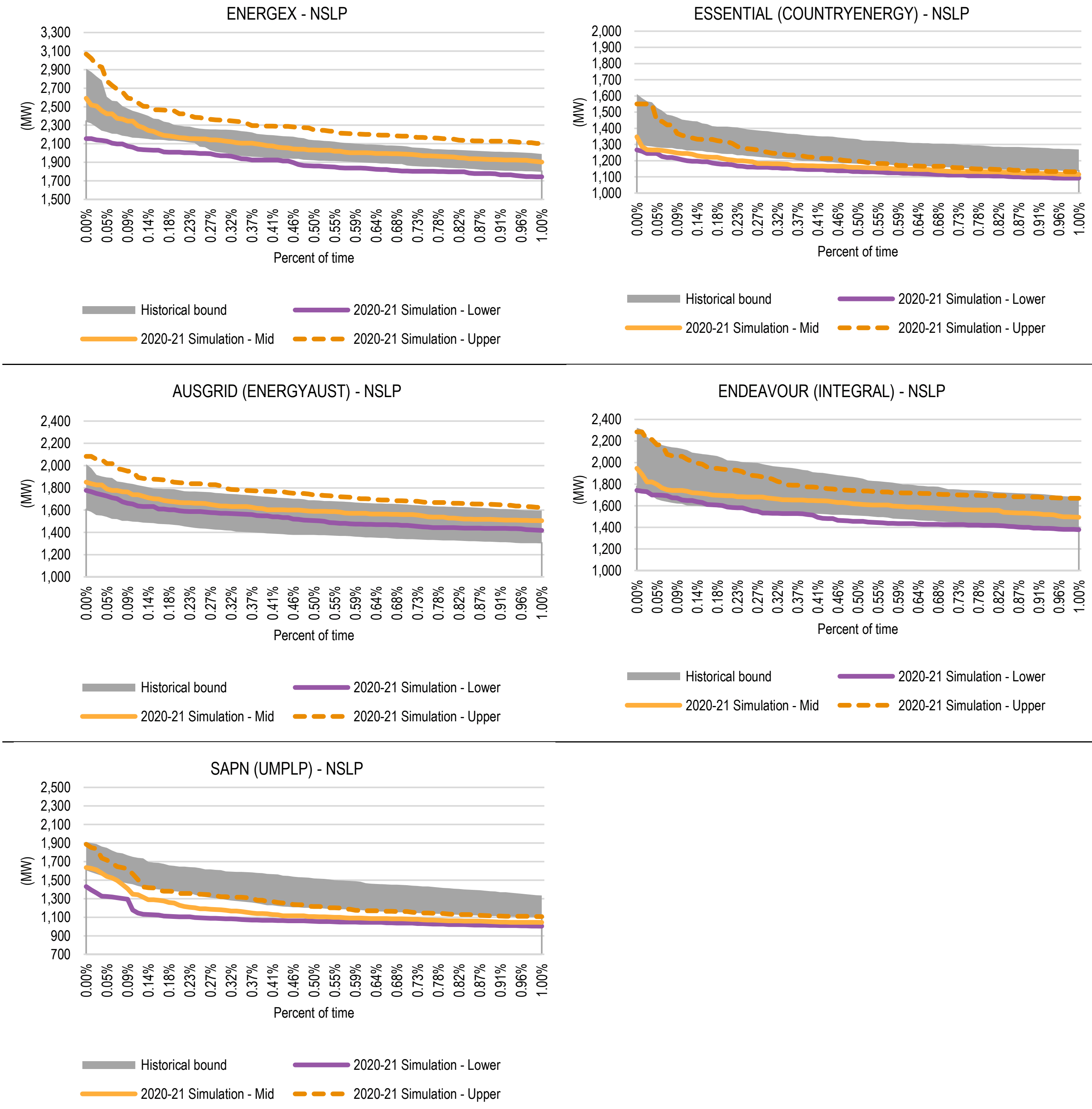
[12] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

— 32 percent and 40 percent compared with a range of 41 percent to 51 percent for the actual Essential NSLP between 2009-10 and 2018-19
— 26 percent and 31 percent compared with a range of 31 percent to 36 percent for the actual Ausgrid NSLP between 2009-10 and 2018-19
— 25 percent and 34 percent compared with a range of 31 percent to 39 percent for the actual Endeavour NSLP between 2009-10 and 2018-19
— 20 percent and 27 percent compared with a range of 21 percent to 33 percent for the actual SAPN NSLP between 2009-10 and 2018-19.

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 4.17 TOP ONE PERCENT HOURLY DEMANDS - NSLPS



SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

FIGURE 4.18 COMPARISON OF LOAD FACTOR OF 2020-21 SIMULATED HOURLY DEMAND DURATION CURVES AND HISTORICAL OUTCOMES - NSLPS

SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

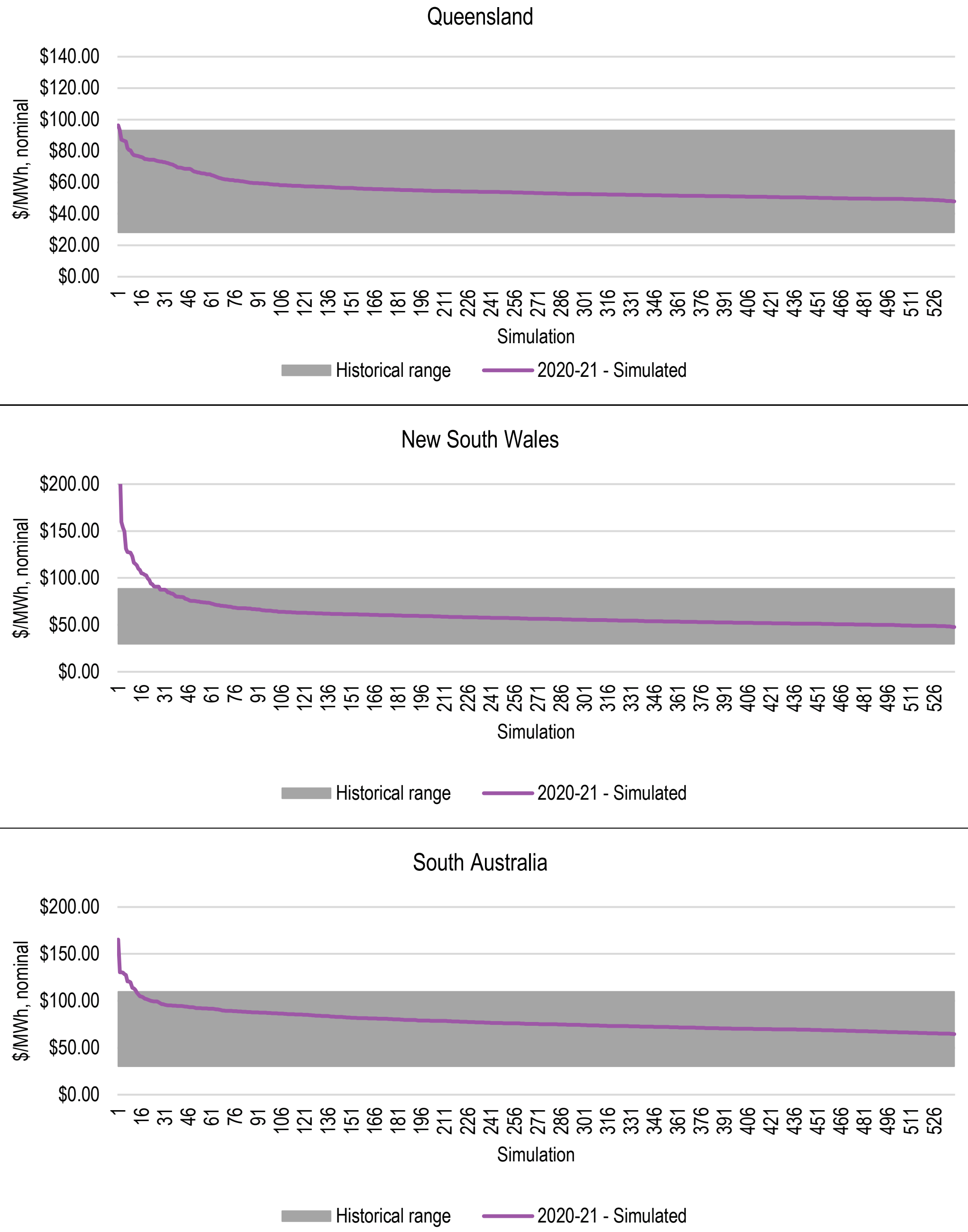
Figure 4.19 compares the modelled annual regional TWP for the 539 simulations for 2020-21 with the regional TWPs from the past 19 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential prices for 2020-21 when compared with the past 19 years of history. The lower part of the distribution of annual simulated outcomes sits above a number of the actual annual outcomes (particularly for the earlier years of the market), due to the increase in gas prices in recent years, and the operating costs of coal plant have increased since the market's inception, and these, coupled with the assumed substantial demand growth due to the LNG terminals in Queensland, have the effect of influencing an increase in the lower bound of annual price outcomes.

The upper bound of the simulations for 2020-21 sits well above the historic upper bound of actual outcomes for New South Wales and South Australia, and at about the same level as the upper bound of historical outcomes in Queensland.

In Queensland, the modelling assumes the commencement of CleanCo from July 2019 in which we assume Wivenhoe to operate more frequently since it is no longer part of a large portfolio, which will place a natural cap on price outcomes. In New South Wales, the recent observed increase in variation in thermal power station availability has been included in the simulations which contributes to the increase in range of simulated annual price outcomes.

ACIL Allen is satisfied that in an aggregate sense the distribution of the 539 simulations for 2020-21 cover an adequately wide range of possible annual pool price outcomes for all three regions.

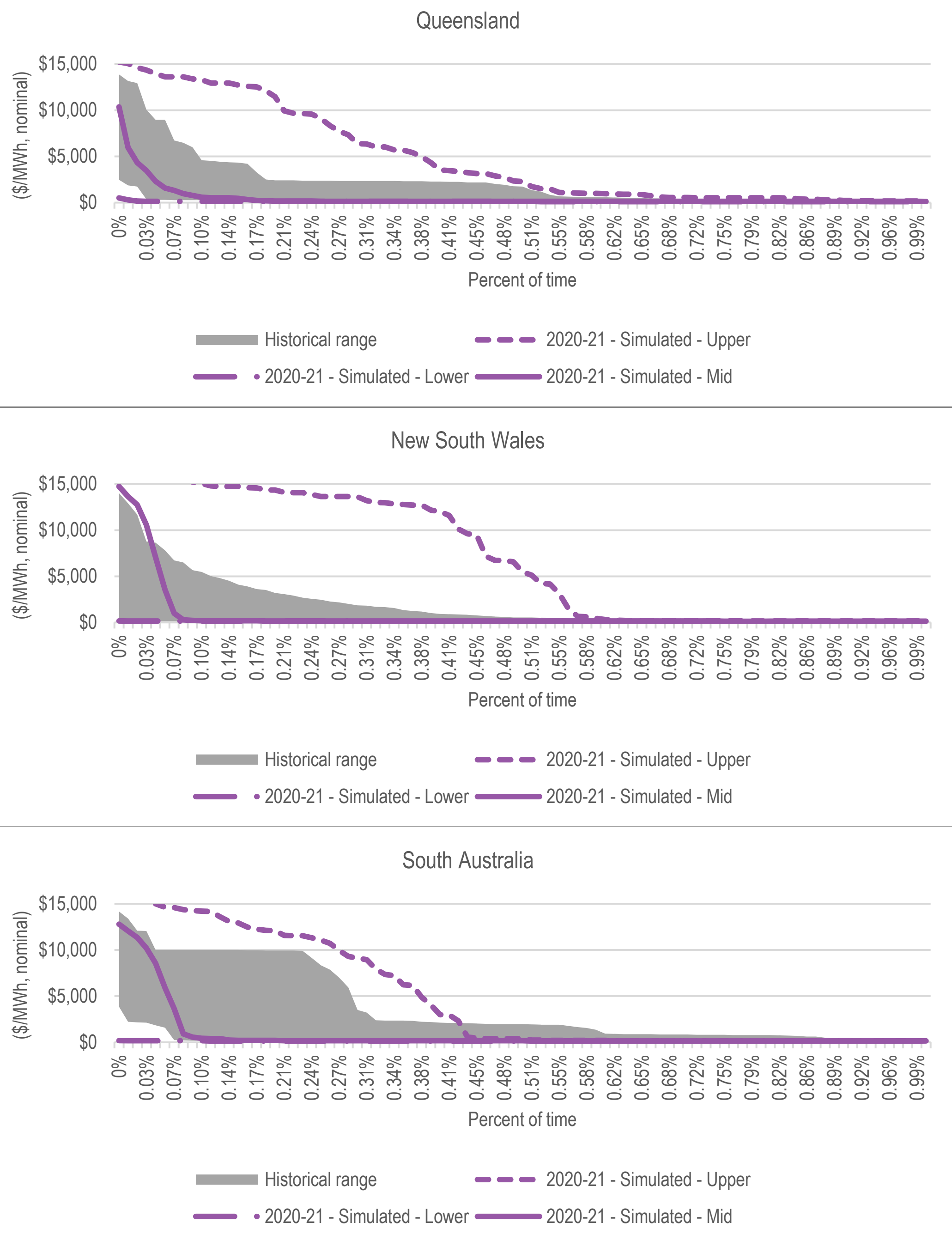
FIGURE 4.19 ANNUAL TWP FOR QUEENSLAND, NEW SOUTH WALES, AND SOUTH AUSTRALIA FOR 539 SIMULATIONS FOR 20-21 COMPARED WITH RANGE OF ACTUAL ANNUAL OUTCOMES IN PAST YEARS



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

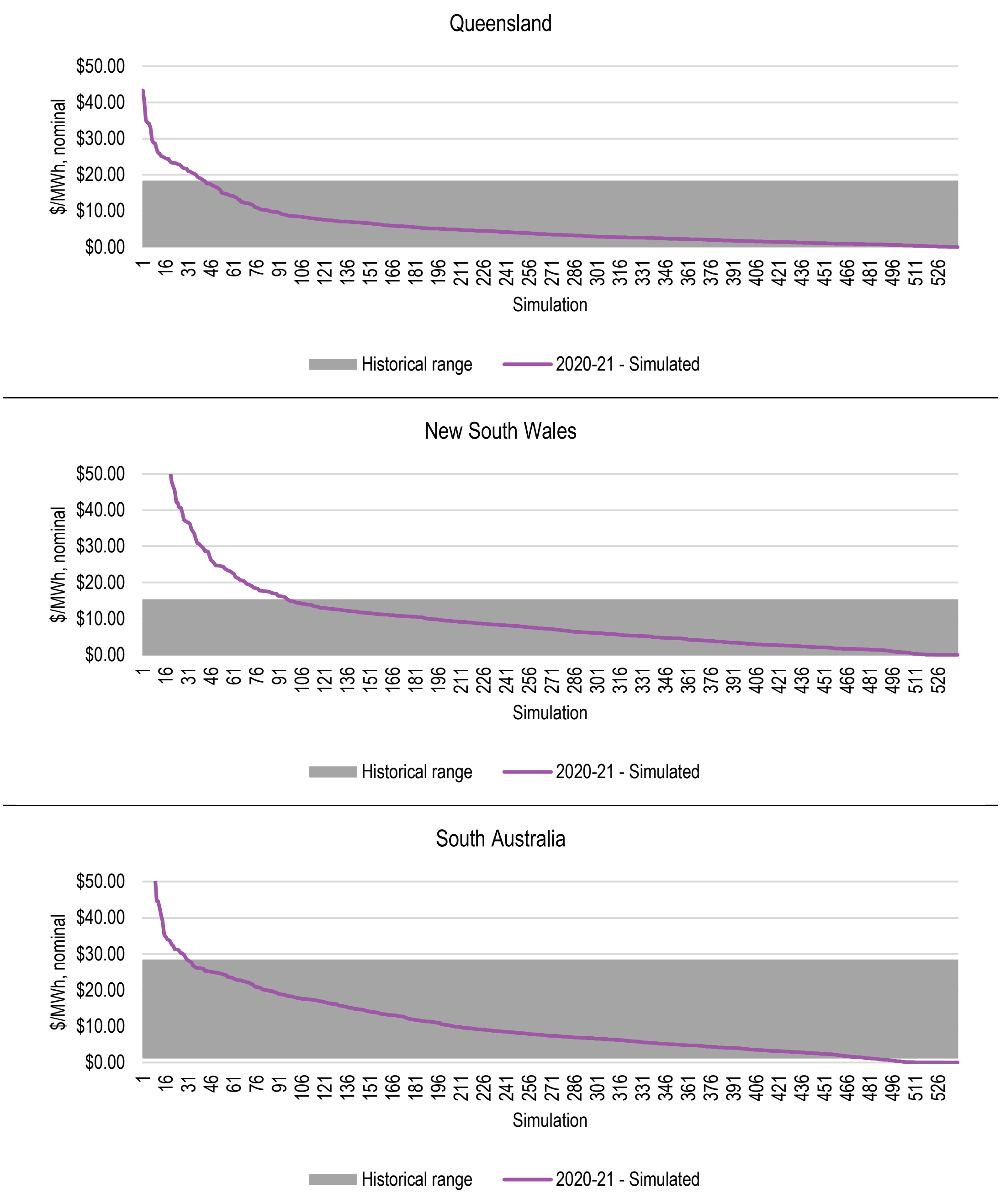
FIGURE 4.20 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND, NEW SOUTH WALES AND SOUTH AUSTRALIA FOR 2020-21 AND RANGE OF HISTORICAL OUTCOMES



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 539 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 539 simulations is consistent with those recorded in history as shown in Figure 4.21.

FIGURE 4.21 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND, NEW SOUTH WALES, AND SOUTH AUSTRALIA TWP BY PRICES ABOVE $300/MWH IN 2020-21 FOR 539 SIMULATIONS COMPARED WITH RANGE OF ACTUAL OUTCOMES IN PAST YEARS



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

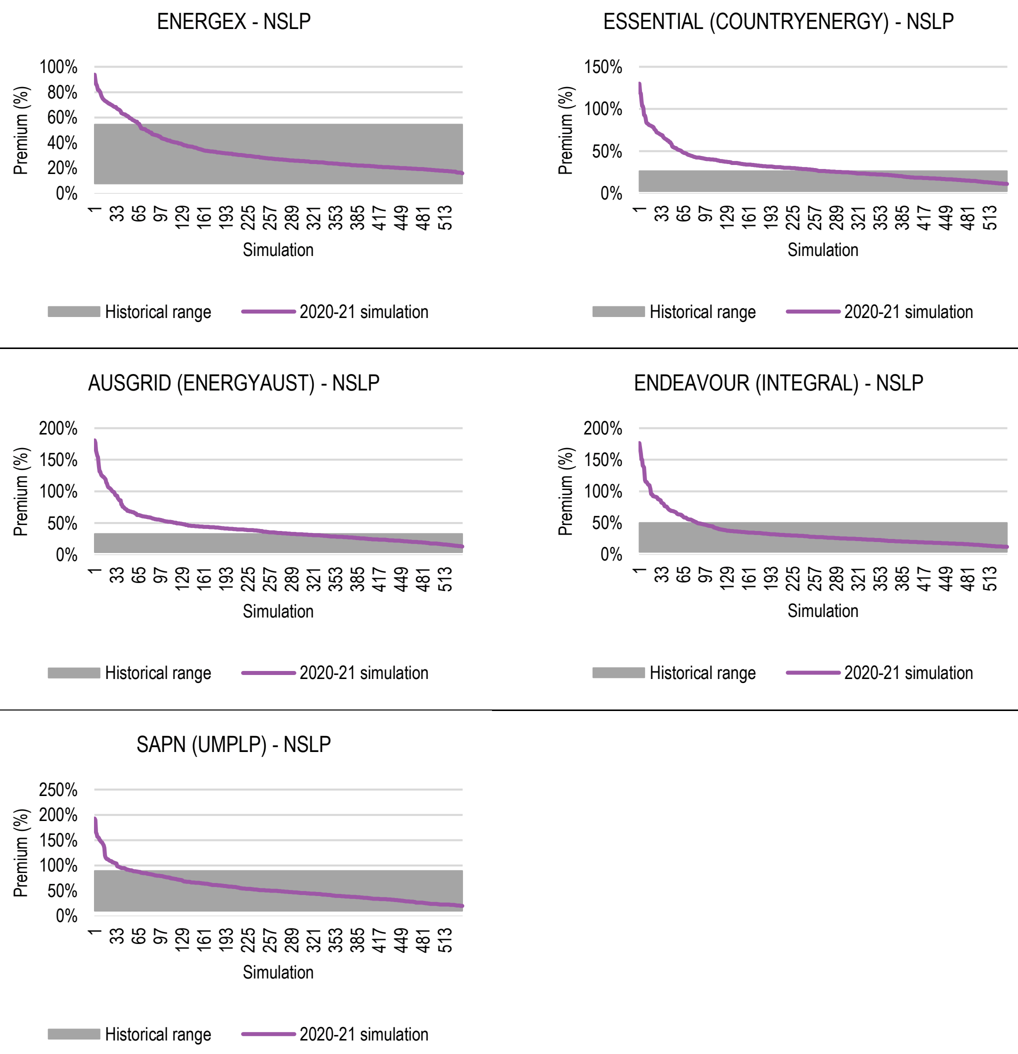
The maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. The shape of the NSLP demand trace and its relationship to the shape of the regional demand/price traces is a critical factor in the cost of supplying the NSLP demand.

A test of the appropriateness of the 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 4.22 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 539 simulations for 2020-21 for each NSLP, this percentage varies from 12 percent to 193 percent. The modelling suggests a greater range in the premium for 2020-21 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 5,000 MW or so of renewable energy projects between now and 2021.

The comparison with actual outcomes over the past 10 years in Figure 4.22 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 539 simulations is sound.

FIGURE 4.22 ANNUAL DWP FOR NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR 539 SIMULATIONS FOR 2020-21 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 539 simulations cover the range of expected price outcomes for 2020-21 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 49 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 2020-21.

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 2020-21 are calculated for each NSLP for each quarter as follows:

— The base contract volume is set to equal the 50th (Essential, Endeavour, SAPN), 60th (Energex[13], Ausgrid) percentile of the off-peak period hourly demands across all 49 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 49 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 49 demand sets minus the base and peak contract volumes.

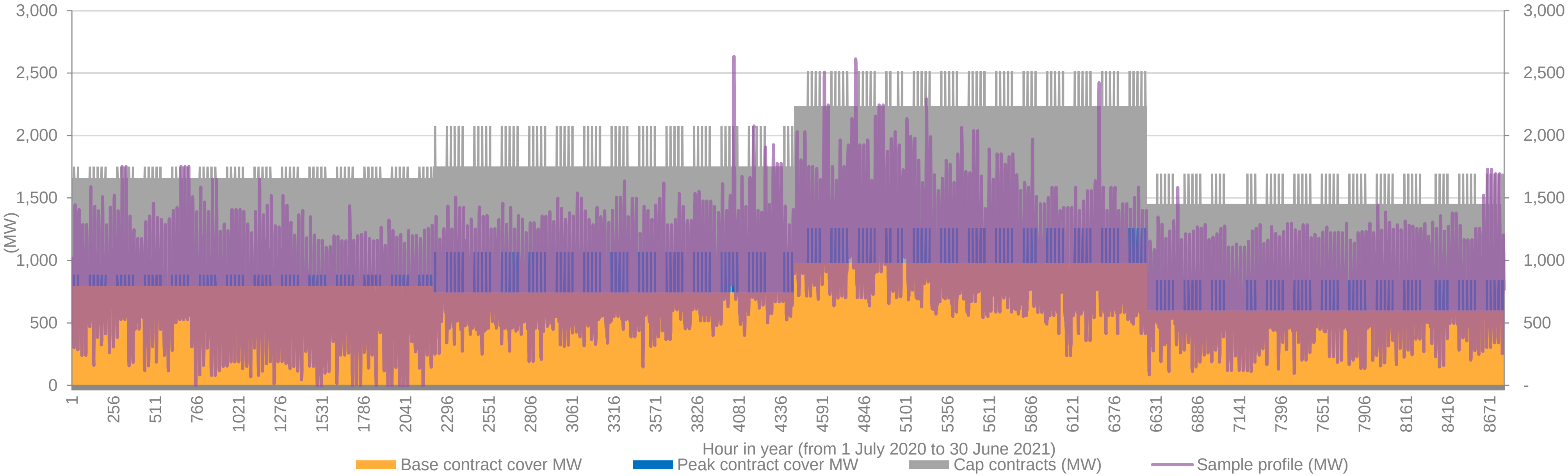
In other words, the same hourly hedge volumes (in MW terms) apply to each of the 49 demand sets for a given NSLP and year, and hence to each of the 539 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 49 demand sets. Therefore, the approach 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 539 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.23 to Figure 4.27.

Generally, the contracting strategies place little, if any, reliance on peak contracts – with the notable exception being the Energex NSLP. This is not surprising – the trade weighted price differential between base and peak contracts in Queensland is about $10/MWh (on an annual basis), compared with a differential of $16/MWh in New South Wales, and $26/MWh in South Australia. In other words, peak contracts in Queensland are relatively more attractive than in New South Wales and South Australia. As a consequence, the hedging strategy search algorithm finds there is benefit in entering into peak contract arrangements for the Energex NSLP. If the differential between peak and base contract prices in New South Wales and South Australia was smaller, then the resulting strategy may well include more peak contracts for the NSLPs in these regions.

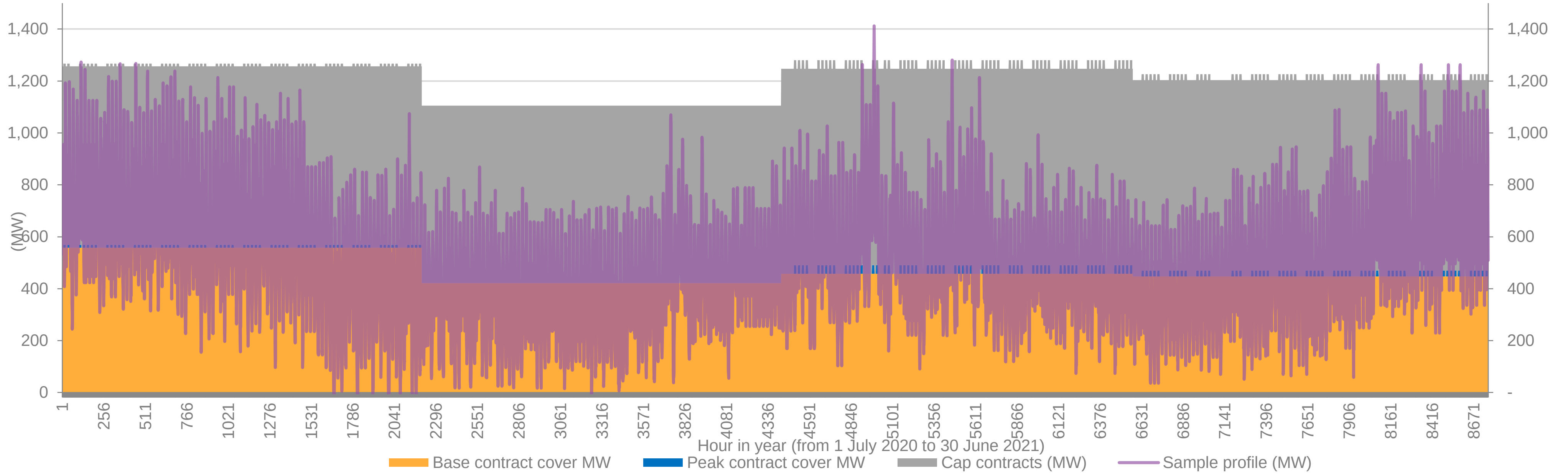
[13] For 2019-20, we have used the hedging strategy adopted for the QCA 2019-20 determination for the Energex NSLP – to remain consistent with that determination. However, given the continued strong uptake in rooftop PV over the past 12 months in Queensland, we have adjusted the strategy slightly for 2020-21.

FIGURE 4.23 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR ENERGEX NSLP



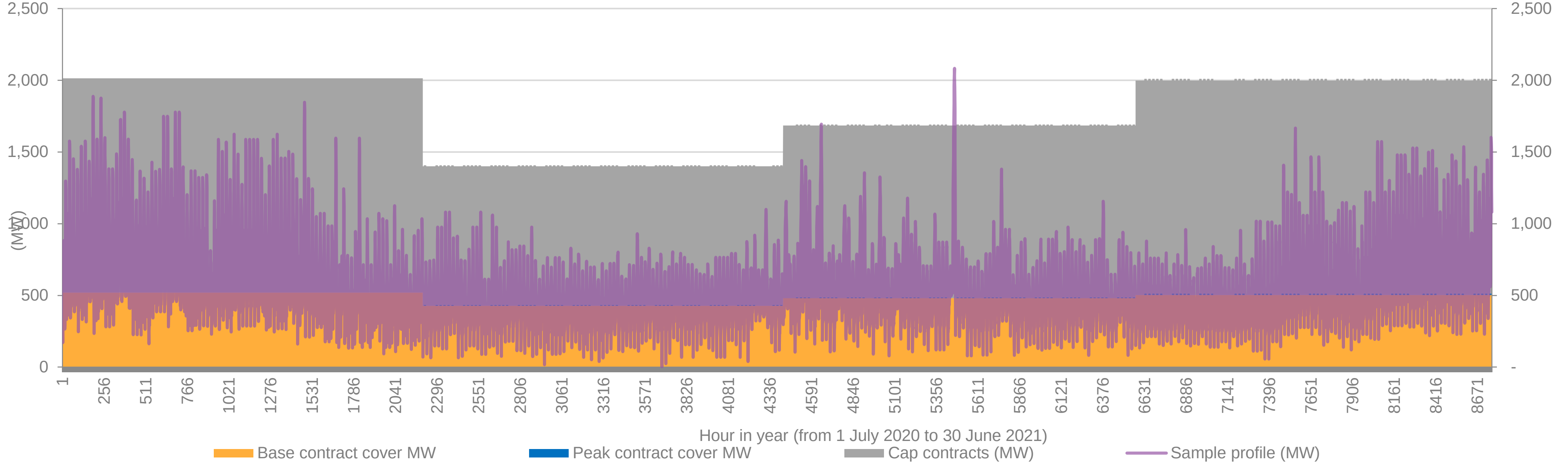
SOURCE: ACIL ALLEN

FIGURE 4.24 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR ESSENTIAL (COUNTRYENERGY) NSLP



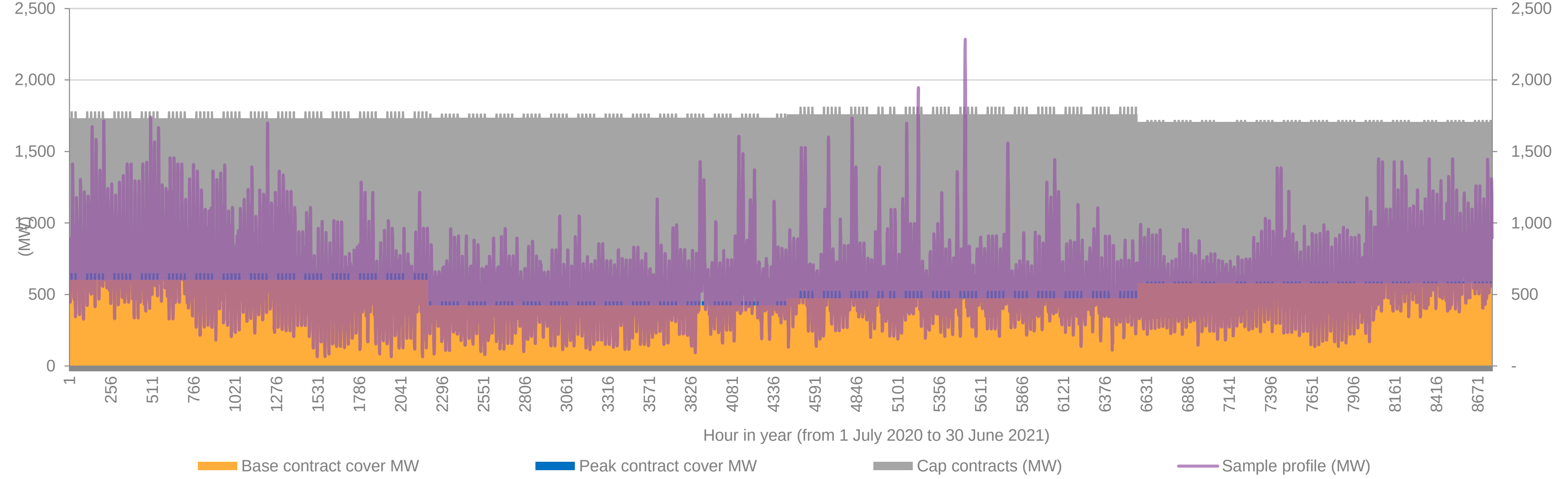
SOURCE: ACIL ALLEN

FIGURE 4.25 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR AUSGRID (ENERGYAUST) NSLP



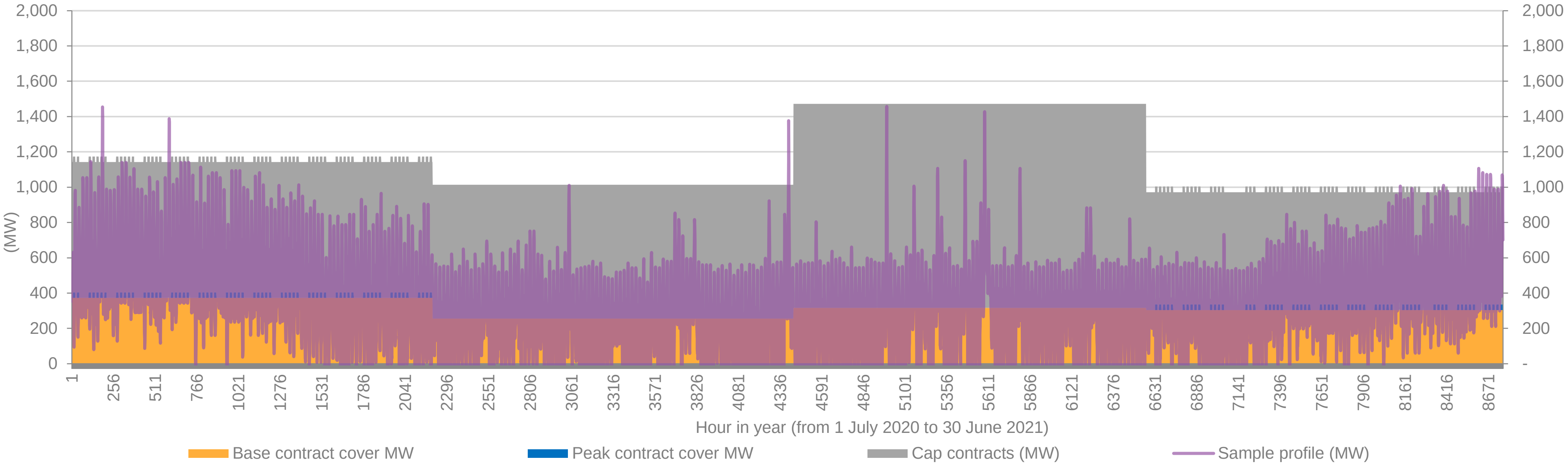
SOURCE: ACIL ALLEN

FIGURE 4.26 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR ENDEAVOUR (INTEGRAL) NSLP



SOURCE: ACIL ALLEN

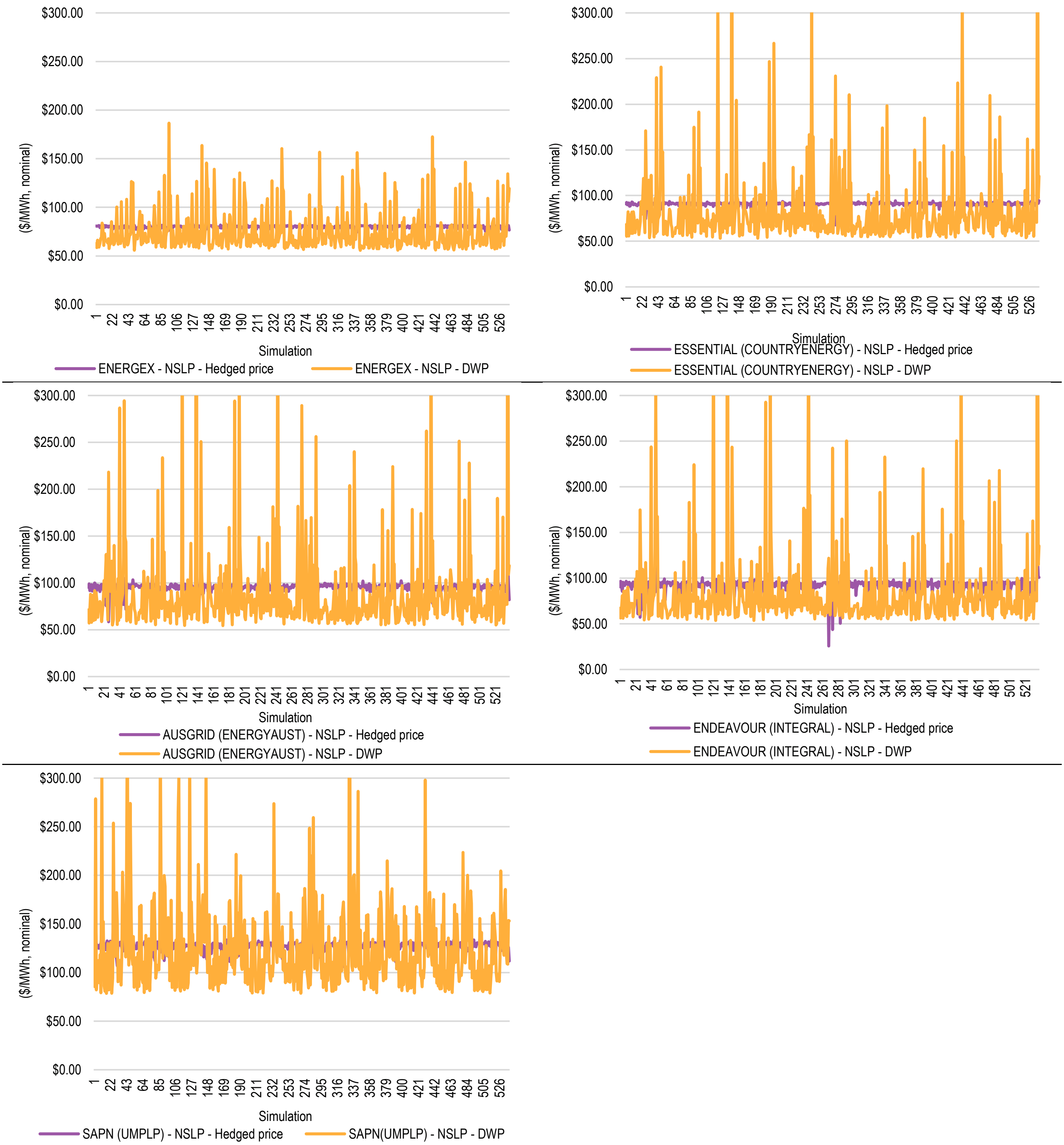
FIGURE 4.27 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR SAPN (UMPLP) NSLP



SOURCE: ACIL ALLEN

Figure 4.28 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 4.28 ANNUAL HEDGED PRICE AND DWP ($/MWH, NOMINAL) FOR NSLPS FOR THE 539 SIMULATIONS – 2020-21



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 539 annual hedged prices. ACIL Allen's estimate of the WEC for each profile for 2019-20 and 2020-21 are shown in Table 4.4.

TABLE 4.4 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2019-20 AND 2020-21 AT THE REGIONAL REFERENCE NODE

Settlement classes	2019-20	2020-21	Change from 2019-20 to 2020-21 (%)
Ausgrid - NSLP	$102.99	$100.92	-2.00%
Endeavour - NSLP	$99.94	$101.07	1.13%
Essential - NSLP	$94.69	$93.84	-0.90%
Ausgrid - CLP1	$76.74	$65.44	-14.72%
Ausgrid - CLP2	$72.46	$63.63	-12.18%
Endeavour - CLP	$90.44	$93.20	3.05%
Essential - CLP	$87.08	$79.06	-9.21%
Energex - NSLP	$89.16	$82.45	-7.52%
Energex - CLP1	$64.91	$64.32	-0.90%
Energex - CLP2	$72.85	$65.99	-9.43%
SAPN - NSLP	$141.39	$132.61	-6.21%
SAPN - CLP	$92.23	$77.58	-15.89%

SOURCE: ACIL ALLEN ANALYSIS

The WECs for the New South Wales NSLPs decrease slightly (Ausgrid and Essential) or increase slightly (Endeavour) between 2019-20 and 2020-21. This is despite a slight decrease overall in the contract prices between these two years. However, contract prices in quarter one and four (the summer quarters) do not change and decrease only be three per cent respectively – and it is these quarters that tend to display the great level of volatility in terms of demand and spot price outcomes. Further, the projected continued uptake of rooftop PV installations for customers in these networks is resulting in the profiles becoming sufficiently peakier so as to increase the cost of hedging the NSLP profiles (all other things equal). Further, the WEC for the Endeavour NSLP increases whereas the WECs for the Ausgrid and Essential NSLPs decrease slightly. Historical data (see Figure 4.2) shows the time of day shape of the Endeavour NSLP tends to exhibit a higher degree of volatility which will be influencing the projected WEC estimates.

The WECs for the NSLPs in Queensland and South Australia decline between 2019-20 and 2020-21 as a result of stronger declines in contract prices (compared with New South Wales) and less change in the demand profiles since the penetration of rooftop PV is much greater already in these two regions compared with New South Wales.

As discussed earlier, the WEC for each tariff class is unlikely to increase (or decrease for that matter) by the same amount between one determination and the next – whether in dollar or percentage terms – due to their different load shapes and differences in how the load shapes are changing over time.

The change in WEC for the CLPs is a mixed result – with some increasing slightly, and others decreasing by 15 per cent between 2019-20 and 2020-21. The change in WEC of the CLPs is reflecting the change in shape of the load profiles. For example, the Endeavour CLP WEC increases by about three per cent between 2019-20 and 2020-21 – this is largely a result of the change in its shape as discussed earlier. It is worth noting that it is the distribution network service providers more than consumer behaviour that control the shape of the CLPs.

4.3 Estimation of renewable energy policy costs

Renewable energy scheme (RET)

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

Energy costs associated with the LRET and the SRES have been estimated using price information from brokers TFS, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen. Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2019, 2020 and 2021 calendar years, with the costs averaged to estimate the 2019-20 and 2020-21 financial year costs.[15]

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 2019, 2020 and 2021 from brokers TFS[16]
— the Renewable Power Percentages (RPPs) for 2019 and 2020 of 18.60 per cent and 19.31 per cent, respectively, as published by the CER (the published RPP for 2020 used in the 2020-21 estimate only)
— estimated RPP values for 2020 of 19.61 per cent (used in the 2019-20 estimate only) and for 2021 of 19.44 per cent, respectively[17]
— the binding Small-scale Technology Percentages (STPs) for 2019 and 2020 of 21.73 per cent and 24.4 per cent, respectively, as published by the CER
— estimated STP value for 2021 of 22.15 per cent[18]
— CER clearing house price[19] for 2020 and 2021 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.

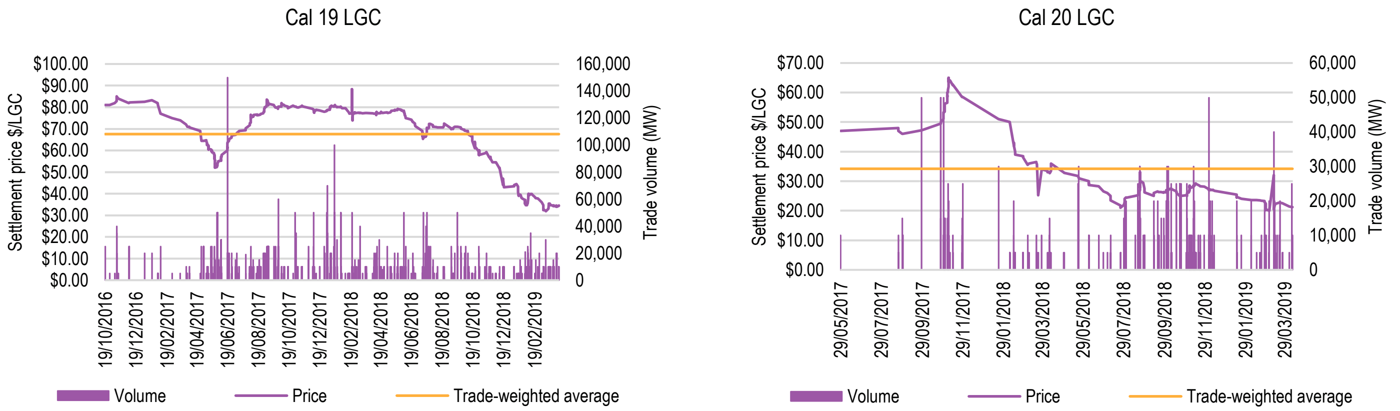
ACIL Allen has estimated the average LGC price using LGC forward prices provided by broker TFS.

The LGC price used in assessing the cost of the scheme for 2019-20 and 2020-21 is found by taking the trade-weighted average of the forward prices for the 2019, 2020 and 2021 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 4.29 and Figure 4.30). The average LGC prices

[14] Emissions Intensive Trade Exposed (EITE) industries such as aluminium are wholly or partially exempted and receive Partial Exemption Certificates (PEC) to be surrendered to the named liable entity.
[15] Two estimates for 2020 have been presented – one for 2019-20, which is assumed to have been calculated in April 2019, and the other for 2020-21, which is calculated using data up to 25 March 2020.
[16] For 2019-20 and 2020-21, TFS data includes prices up to and including 10 April 2019 and 25 March 2020, respectively.
[17] The RPP values for 2020 and 2021 were estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET targets for 2020 and 2021, respectively.
[18] The STP value for 2021 was estimated using ACIL Allen's estimates of STC creations and liable acquisitions in 2021.
[19] 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.

calculated from the TFS data are $67.58/MWh for 2019 and $34.21/MWh for 2020 for 2019-20, and $31.88/MWh for 2020 and $19.28/MWh for 2021 for 2020-21.

FIGURE 4.29 LGC PRICES FOR 2019 AND 2020 FOR 2019-20 ($/LGC, NOMINAL)



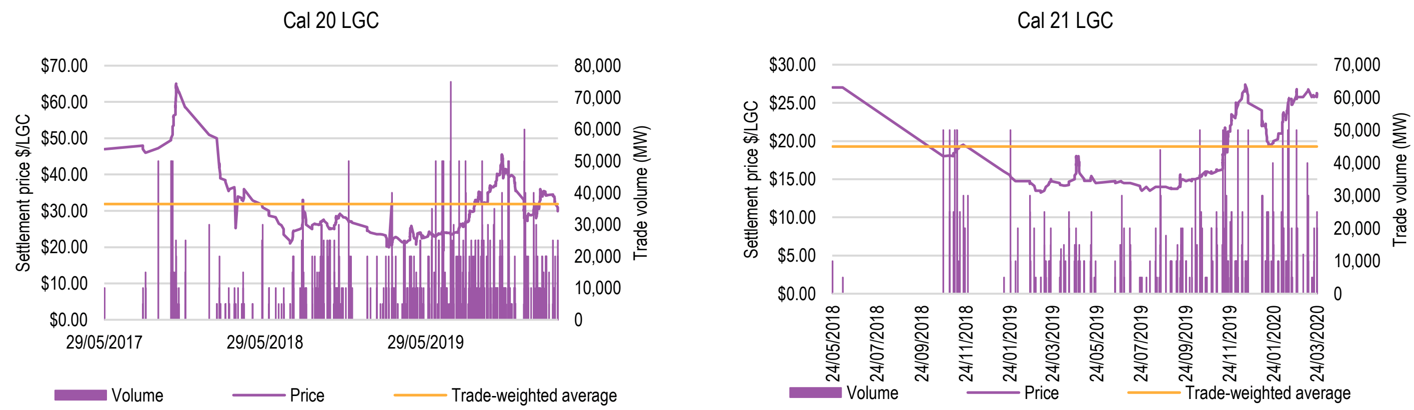
SOURCE: TFS AND ACIL ALLEN ANALYSIS

Since the time of estimating the cost for 2019-20, LGC forward prices have fallen due to:

— A number of renewable projects reaching financial close in recent months with most of the projects expected to be commissioned during 2019 and 2020
  – The surge in investment in renewables have been driven by falling costs of renewables, demand for PPAs from corporates and increased appetite of renewable investors to take on merchant exposure

The significantly lower average price for 2020 reflects the high likelihood that the LRET scheme will be fully subscribed by 2020.

FIGURE 4.30 LGC PRICES FOR 2020 AND 2021 FOR 2020-21 ($/LGC, NOMINAL)



SOURCE: TFS AND ACIL ALLEN ANALYSIS

The published 2019 and 2020 RPP values of 18.60 per cent and 19.31 per cent, respectively, have been set by the CER. The 2020 RPP was set by the CER in March 2020, and therefore is only used in the 2020-21 estimate, since the 2019-20 estimate is assumed to have been set using information up until 10 April 2019.

The estimated 2020 RPP value of 19.61 per cent is estimated using information up until 10 April 2019, by using the mandated target for 2020 of 33.8 TWh and ACIL Allen's estimate of electricity acquisitions in 2020 of 172.6 TWh.

The estimated 2020 RPP of 19.61 per cent is different to the CER's published 2020 RPP of 19.31 per cent, because of a difference in estimated electricity acquisitions and the cumulative adjustment to the mandated target to account for voluntarily surrendered LGCs.

Key elements of the 2020 RPP estimation are shown inTable 4.5.

TABLE 4.5 ESTIMATING THE 2020 RPP VALUE (USED IN 2019-20 ONLY)

	2020
LRET target, MWh (CER)	33,850,000
Estimated electricity acquisitions, MWh (ACIL Allen)	172,572,480
Estimated RPP	19.61%

NOTE: FOR USE IN THE 2019-20 ESTIMATE ONLY
SOURCE: CER AND ACIL ALLEN ANALYSIS

The estimated 2021 RPP value of 19.44 per cent was estimated using the mandated target for 2021 of 33 TWh and ACIL Allen's estimate of relevant acquisitions minus exemptions of 169.7 TWh, which was also used in the denominator of the 2021STP estimate.

Key elements of the 2021 RPP estimation are shown in Table 4.6.

TABLE 4.6 ESTIMATING THE 2021 RPP VALUE

	2021
LRET target, MWh (CER)	33,000,000
Relevant acquisitions minus exemptions, MWh (CER)	169,720,876
Estimated RPP	19.44%

SOURCE: CER AND ACIL ALLEN ANALYSIS

ACIL Allen calculates the cost of complying with the LRET in 2019 and 2020 by multiplying the RPP values for 2019 and 2020 by the average LGC prices for 2019 and 2020, respectively. The cost of complying with the LRET in 2019-20 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $9.64/MWh in 2019-20 as shown in Table 4.7.

TABLE 4.7 ESTIMATED COST OF LRET – 2019-20

	2019	2020	Cost of LRET 2019-20
RPP %	18.60%	19.61%	
Average LGC price ($/LGC, nominal)	$67.58	$34.21	
Cost of LRET ($/MWh, nominal)	$12.57	$6.71	$9.64

SOURCE: CER, TFS, ACIL ALLEN ANALYSIS

ACIL Allen calculates the cost of complying with the LRET in 2020 and 2021 by multiplying the RPP values for 2020 and 2021 by the average LGC prices for 2020 and 2021, respectively. The cost of complying with the LRET in 2020-21 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $4.95/MWh in 2020-21 as shown in Table 4.8.

TABLE 4.8 ESTIMATED COST OF LRET – 2020-21

	2020	2021	Cost of LRET 2020-21
RPP %	19.31%	19.44%	
Average LGC price ($/LGC, nominal)	$31.88	$19.28	
Cost of LRET ($/MWh, nominal)	$6.16	$3.75	$4.95

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 2019-20 and 2020-21.

As discussed earlier, the estimate for 2019-20 is assumed to have been calculated in April 2019, using the following inputs:

- The CER's binding 2019 STP of 21.73 per cent (equivalent to 37.5 million STCs as a proportion of total estimated electricity consumption for the 2019 year). This estimate includes an uplift of 7.9 million STCs due to the carryover of overflow STCs from 2018.
- The CER's binding 2020 STP of 24.40 per cent (equivalent to 42.6 million STCs as a proportion of total estimated electricity consumption for the 2020 year). This estimate includes an uplift of 5.9 million STCs due to the carryover of overflow STCs from 2019.

The binding 2020 STP of 24.4 per cent has been used in the 2019-20 estimate to account for the overflow STCs from 2019 that would have been incurred in the 2019-20 year.

ACIL Allen estimates the cost of complying with SRES to be $9.23/MWh in 2019-20 as set out in Table 4.9.

TABLE 4.9 ESTIMATED COST OF SRES – 2019-20

	2019	2020	Cost of SRES 2019-20
STP %	21.73%	24.4%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$8.69	$9.76	$9.23

SOURCE: ACIL ALLEN ANALYSIS

The estimate for 2020-21, which incorporates all available information to date, uses the following inputs:

- The CER's binding 2020 STP of 24.4 per cent (equivalent to 42.6 million STCs as a proportion of total estimated electricity consumption for the 2020 year). This estimate includes an uplift of 5.9 million STCs due to the carryover of overflow STCs from 2019.
- ACIL Allen's estimate of the STP value for 2021 of 22.15 per cent - equivalent to 37.6 million STCs as a proportion of total estimated electricity consumption for the 2021 year. This is lower than the 2020 estimate due to an expectation that SGU installations will be at similar levels to 2020 and that the 2020 STP value is a reasonably accurate of estimate of actual STC creations in 2020 (i.e. no overflow from 2020 to 2021).

ACIL Allen estimates the cost of complying with SRES to be $9.31/MWh in 2020-21 as set out in Table 4.10. The cost of SRES in 2020-21 is estimated to be slightly higher than in 2019-20.

TABLE 4.10 ESTIMATED COST OF SRES – 2020-21

	2020	2021	Cost of SRES 2020-21
STP %	24.4%	22.15%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$9.76	$8.86	$9.31

SOURCE: ACIL ALLEN ANALYSIS

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2019-20 and 2020-21 as set out in Table 4.11.

Since the 2019-20 estimate, the cost of LRET has decreased by around 49 per cent, driven by lower LGC prices in 2020-21 and the cost of SRES has increased by one per cent, driven by slightly higher expected installations in 2021.

TABLE 4.11 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH, NOMINAL)

	2019-20	2020-21	Change
LRET	$9.64	$4.95	($4.69)
SRES	$9.23	$9.31	$0.08
Total	$18.87	$14.26	($4.61)

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 2019, 2020 and 2021 of 8.5 per cent, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2019, 2020 and 2021 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 2019-20 and 2020-21, as set out in Table 4.12 and Table 4.13, respectively.

TABLE 4.12 ESTIMATED COST OF ESS ($/MWH, NOMINAL) – 2019-20

	2019	2020	Cost of ESS 2019-20
ESS target	8.5%	8.5%	
Average ESC price ($/MWh, nominal)	$21.49	$20.80	
Cost of ESS ($/MWh, nominal)	$1.83	$1.77	$1.80

SOURCE: IPART, TFS

TABLE 4.13 ESTIMATED COST OF ESS ($/MWH, NOMINAL) – 2020-21

	2020	2021	Cost of ESS 2020-21
ESS target	8.5%	8.5%	
Average ESC price ($/MWh, nominal)	$24.51	$24.75	
Cost of ESS ($/MWh, nominal)	$2.08	$2.10	$2.09

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.[20]

In the AEMC's 2019 price trends report[21], the cost of REES appears to be unchanged from the 2018 report.

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 has used the estimates of the cost of REES provided in the latest AEMC price trends report.

TABLE 4.14 ESTIMATED COST OF REES ($/MWH, NOMINAL)

	2019-20	2020-21
Cost of REES	$2.50	$2.50

SOURCE: AEMC

4.4 Estimation of other energy costs

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

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

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the National Transmission Planner (NTP) and the Energy Consumers Australia (ECA)[22].

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2018-19* and *Electricity Final Budget & Fees 2019-20*, the fees for 2019-20 and 2020-21 are $0.63/MWh and $0.71/MWh, respectively. The breakdown of total fees is shown in Table 4.15.

[20] 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

[21] Published on 9 December 2019 at: https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2019

[22] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2018-19* 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 4.15 NEM MANAGEMENT FEES ($/MWH, NOMINAL)

Cost category	2019-20	2020-21
NEM fees (admin, registration, etc.)	$0.50	$0.56
FRC - electricity	$0.080	$0.077
NTP - electricity	$0.025	$0.040
ECA - electricity	$0.029	$0.032
Total NEM management fees	**$0.63**	**$0.71**

SOURCE: AEMO, AER

4.4.2 Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs over the preceding 52 weeks of currently available NEM ancillary services data as a basis for 2020-21, the cost of ancillary services is estimated to be $1.53/MWh.

Using the average costs over the 52 weeks preceding April 2019, the estimate for 2019-20 is $0.37/MWh.

The increase in the estimate for 2020-21 is due a number of events that increased the demand for and price of FCAS services including, the Basslink outage in August 2019 to October 2019, the planned outage of the Heywood to Mortlake line in September 2019, the South Australian islanding in November 2019 and the VIC-SA interconnector outage in January 2020.[23]

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 4.16 for each season for Ausgrid NSLP gives an estimated MCL of $9,553.

[23] For the purposes of FCAS recovery, the market is treated globally. Hence, for the purpose of recovery, participants are treated equally, regardless of region.

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 $9,553/42 = $227.45/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 $227.45 gives $0.65/MWh for Ausgrid NSLP, as shown in Table 4.16.

The components of the AEMO prudential costs for each of the other jurisdictions' NSLPs are shown in Table 4.17, Table 4.18, Table 4.19 and Table 4.20.

TABLE 4.16 AEMO PRUDENTIAL COSTS FOR AUSGRID NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$98.14	$65.01	$49.44
Participant Risk Adjustment Factor	1.9434	1.4395	1.1243
OS Volatility factor	1.48	1.32	1.35
PM Volatility factor	2.75	1.88	1.77
OSL	$15,150	$5,706	$3,063
PML	$3,030	$1,141	$613
MCL	$18,180	$6,848	$3,676
Average MCL		$9,553	
AEMO prudential cost ($/MWh, nominal)		**$0.65**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.17 AEMO PRUDENTIAL COSTS FOR ENDEAVOUR NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$98.14	$65.01	$49.44
Participant Risk Adjustment Factor	1.7539	1.2434	1.1435
OS Volatility factor	1.48	1.32	1.35
PM Volatility factor	2.75	1.88	1.77
OSL	$12,990	$4,581	$3,142
PML	$2,598	$916	$628
MCL	$15,588	$5,497	$3,770
Average MCL		$8,270	
AEMO prudential cost ($/MWh, nominal)		**$0.57**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.18 AEMO PRUDENTIAL COSTS FOR ESSENTIAL NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$98.14	$65.01	$49.44
Participant Risk Adjustment Factor	1.4838	1.2223	1.1421
OS Volatility factor	1.48	1.32	1.35
PM Volatility factor	2.75	1.88	1.77
OSL	$10,107	$4,465	$3,136
PML	$2,021	$893	$627
MCL	$12,129	$5,358	$3,763
Average MCL		$7,074	
AEMO prudential cost ($/MWh, nominal)		**$0.48**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.19 AEMO PRUDENTIAL COSTS FOR ENERGEX NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$81.16	$45.94	$52.47
Participant Risk Adjustment Factor	1.5292	1.2993	1.2775
OS Volatility factor	1.62	1.28	1.35
PM Volatility factor	3.10	1.79	2.07
OSL	$9,572	$3,353	$3,938
PML	$1,914	$671	$788
MCL	$11,486	$4,024	$4,725
Average MCL		$6,730	
AEMO prudential cost ($/MWh, nominal)		**$0.46**	

SOURCE: ACIL ALLEN ANALYSIS, AEMO

TABLE 4.20 AEMO PRUDENTIAL COSTS FOR SAPN NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$125.13	$85.23	$70.94
Participant Risk Adjustment Factor	2.7020	1.1684	1.3026
OS Volatility factor	1.84	1.47	1.42
PM Volatility factor	4.92	2.24	1.88
OSL	$39,369	$6,092	$5,765
PML	$7,874	$1,218	$1,153
MCL	$47,242	$7,310	$6,919
Average MCL		$20,418	
AEMO prudential cost ($/MWh, nominal)		**$1.40**	

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 0.50 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 4.21. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 6.80 per cent but adjusted for an assumed 0.50 per cent return on cash lodged with the clearing (giving a net funding cost of 6.30 percent) results in the prudential cost per MWh for each contract type.

Average initial margins for Queensland and South Australia, using their corresponding initial margin parameters, and the resulting prudential cost per MWh are shown in Table 4.22 and Table 4.23, respectively.

TABLE 4.21 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – NEW SOUTH WALES 2020-21

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$73.16	$29,000	$0.83
Peak	$89.99	$25,000	$1.67
Cap	$8.78	$12,000	$0.35

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

TABLE 4.22 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – QUEENSLAND 2020-21

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$62.11	$25,000	$0.72
Peak	$72.22	$25,000	$1.67
Cap	$5.22	$9,000	$0.26

SOURCE: ACIL ALLEN ANALYSIS, ASX ENERGY, RBA

TABLE 4.23 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE – SOUTH AUSTRALIA 2020-21

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$77.41	$45,000	$1.29
Peak	$96.92	$48,000	$3.21
Cap	$12.56	$20,000	$0.58

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 4.24, Table 4.25, Table 4.26, Table 4.27 and Table 4.28.

TABLE 4.24 HEDGE PRUDENTIAL FUNDING COSTS FOR AUSGRID NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.83	0.9007	$0.75
Peak	$1.67	0.0049	$0.01
Cap	$0.35	2.4142	$0.83
Total cost		**$1.59**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.25 HEDGE PRUDENTIAL FUNDING COSTS FOR ENDEAVOUR NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.83	0.8800	$0.73
Peak	$1.67	0.0264	$0.04
Cap	$0.35	2.0538	$0.71
Total cost		**$1.49**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.26 HEDGE PRUDENTIAL FUNDING COSTS FOR ESSENTIAL NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.83	1.0825	$0.90
Peak	$1.67	0.0000	$0.00
Cap	$0.35	0.7764	$0.27
Total cost		**$1.17**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.27 HEDGE PRUDENTIAL FUNDING COSTS FOR ENERGEX NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.72	0.9931	$0.71
Peak	$1.67	0.1156	$0.19
Cap	$0.26	1.2956	$0.34
Total cost		**$1.24**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.28 HEDGE PRUDENTIAL FUNDING COSTS FOR SAPN NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.29	1.5345	$1.99
Peak	$3.21	0.0000	$0.00
Cap	$0.58	1.4994	$0.86
Total cost		**$2.85**	

SOURCE: ACIL ALLEN ANALYSIS

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2020-21 as set out in Table 4.29. The calculations have been made for 2019-20 and are also shown in Table 4.29 for comparison. Prudential costs for 2020-21 are generally lower than 2019-20 due to lower hedge prices and lower expected price volatility across 2020-21. Some of the New South Wales NSLPs show a slight increase in prudential costs which reflects higher expected volatility in Q1, which more than offsets lower expected volatility in the other quarters of 2020-21.

TABLE 4.29 TOTAL PRUDENTIAL COSTS ($/MWH, NOMINAL)

Jurisdiction	2019-20	2020-21
Ausgrid NSLP	$2.17	$2.25
Endeavour NSLP	$2.01	$2.05
Essential NSLP	$1.82	$1.66
Energex NSLP	$2.18	$1.70
SAPN NSLP	$4.92	$4.25

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 propose to take the RERT costs as published by AEMO for the 12-month period prior to the determination year.

At the time of writing this report for the Final Determination, the costs of the RERT for 2019-20 have been reported by AEMO – which are contained in the RERT Quarterly Report for Q4 2019 and several RERT activation estimates for Q1 2020. Therefore, the RERT costs incurred over summer 2019-20 have been used to estimate RERT costs for the 2020-21 DMO. These costs apply to the New South Wales region for the 2020-21 DMO and are estimated to be $0.36/MWh.

As in the Draft Determination, the RERT costs incurred over summer 2018-19 have been used to estimate RERT costs for the 2019-20 DMO. These costs apply to the South Australian region for the 2019-20 DMO and are estimated to be $0.63/MWh.

ACIL Allen has expressed the cost based on energy consumption – which requires 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, as shown in Table 4.30 for 2019-20 and Table 4.31 for 2020-21.

TABLE 4.30 ESTIMATED COST OF RERT IN SOUTH AUSTRALIA ($/MWH, NOMINAL) – 2019-20

	2019-20
Total RERT costs in 2018-19 ($'m)	$34.5
SA energy in 2018-19 (GWh)	42,981
VIC energy in 2018-19 (GWh)	11,370
Total energy in 2018-19 (GWh)	54,352
RERT cost ($/MWh, nominal)	**$0.63**

SOURCE: AEMO

TABLE 4.31 ESTIMATED COST OF RERT IN NEW SOUTH WALES ($/MWH, NOMINAL) – 2020-21

	2020-21
Total RERT costs in New South Wales 2019-20 ($'m)	$24.73
NSW energy in 2019-20 (GWh)	68,914
RERT cost ($/MWh, nominal)	**$0.36**

SOURCE: 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 4.35**,** for the 2020-21 Final Determination and is compared with the costs for 2019-20.

TABLE 4.32 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – AUSGRID NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.71
Ancillary services	$0.37	$1.53
Hedge and pool prudential costs	$2.17	$2.25
Reserve and Emergency Reserve Trader	$0.00	$0.36
Total	**$3.17**	**$4.85**

TABLE 4.33 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ENDEAVOUR NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.71
Ancillary services	$0.37	$1.53
Hedge and pool prudential costs	$2.01	$2.05
Reserve and Emergency Reserve Trader	$0.00	$0.36
Total	**$3.01**	**$4.65**

TABLE 4.34 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ESSENTIAL NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.71
Ancillary services	$0.37	$1.53
Hedge and pool prudential costs	$1.82	$1.66
Reserve and Emergency Reserve Trader	$0.00	$0.36
Total	**$2.82**	**$4.26**

TABLE 4.35 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ENERGEX NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.71
Ancillary services	$0.37	$1.53
Hedge and pool prudential costs	$2.18	$1.70
Total	**$3.18**	**$3.94**

TABLE 4.36 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – SAPN NSLP

Cost category	2019-20	2020-21
NEM management fees	$0.63	$0.71
Ancillary services	$0.37	$1.53
Hedge and pool prudential costs	$4.92	$4.25
Reserve and Emergency Reserve Trader	$0.63	$0.00
Total	**$6.55**	**$6.49**

4.5 Estimation of energy losses

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

The MLFs used to estimate losses for 2019-20 are based on the updated draft 2019-20 MLFs published by AEMO on 1 April 2019. The DLFs used to estimate losses for 2019-20 are based on the final DLFs published by AEMO in April 2019.

The MLFs used to estimate losses for the Final Determination for 2020-21 are based on the final 2020-21 MLFs published by AEMO on 1 April 2020. The DLFs used to estimate losses for 2020-21 are based on the final DLFs published by AEMO on 1 April 2020.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2019-20 and 2020-21 is shown in Table 4.37.

TABLE 4.37 ESTIMATED TRANSMISSION AND DISTRIBUTION LOSSES

Settlement class	2019-20			2020-21		
	Distribution losses	Transmission losses	Total loss factor	Distribution losses	Transmission losses	Total loss factor
Ausgrid - NSLP	5.00%	-0.05%	1.049	4.79%	0.16%	1.050
Endeavour - NSLP	6.28%	-0.70%	1.055	6.87%	-0.63%	1.062
Essential - NSLP	6.91%	-1.06%	1.058	6.64%	-1.07%	1.055
Ausgrid - CLP1	5.32%	-0.05%	1.053	5.14%	0.16%	1.053
Ausgrid - CLP2	5.32%	-0.05%	1.053	5.14%	0.16%	1.053
Endeavour - CLP	6.28%	-0.70%	1.055	6.87%	-0.63%	1.062
Essential - CLP	6.91%	-1.06%	1.058	6.64%	-1.07%	1.055
Energex - NSLP	5.59%	0.84%	1.065	5.20%	0.70%	1.059
Energex – CLP31	5.59%	0.84%	1.065	5.20%	0.70%	1.059
Energex – CLP33	5.59%	0.84%	1.065	5.20%	0.70%	1.059
SAPN - NSLP	10.10%	0.82%	1.110	10.70%	0.08%	1.108
SAPN - CLP	10.10%	0.82%	1.110	10.70%	0.08%	1.108

SOURCE: AEMO, ACIL ALLEN ANALYSIS

As described by AEMO[24], 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 2019-20 and 2020-21 total energy costs (TEC) for the Final Determination for each of the profiles are presented in Table 4.38 to Table 4.40.

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

TABLE 4.38 ESTIMATED TEC FOR 2019-20 AND 2020-21 ($/MWH, NOMINAL) - FINAL DETERMINATION

Profile	2019-20 Total energy costs at the customer terminal ($/MWh, nominal)	2020-21 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2019-20 to 2020-21 ($/MWh, nominal)	Change from 2019-20 to 2020-21 (%, nominal)
Ausgrid - NSLP	$133.04	$128.23	($4.81)	-3.62%
Endeavour - NSLP	$130.42	$129.63	($0.79)	-0.61%
Essential - NSLP	$125.04	$120.75	($4.29)	-3.43%
Ausgrid - CLP1	$105.92	$91.24	($14.68)	-13.86%
Ausgrid - CLP2	$101.41	$89.33	($12.08)	-11.91%
Endeavour - CLP	$120.40	$121.28	$0.88	0.73%
Essential - CLP	$116.98	$105.15	($11.83)	-10.11%
Energex - NSLP	$118.44	$106.59	($11.85)	-10.01%
Energex – CLP31	$92.62	$87.39	($5.23)	-5.65%
Energex – CLP33	$101.07	$89.16	($11.91)	-11.78%
SAPN - NSLP	$187.93	$172.69	($15.24)	-8.11%
SAPN - CLP	$133.37	$111.72	($21.65)	-16.23%

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.39 ESTIMATED TEC FOR 2019-20 FINAL DETERMINATION ($/MWH, NOMINAL)

Profile	WEC at regional reference node ($/MWh, nominal)	Other wholesale costs at regional reference node ($/MWh, nominal)	Network loss factor	Wholesale network losses ($/MWh, nominal)	Total wholesale costs at the customer terminal ($/MWh, nominal)	LRET costs at regional reference node ($/MWh, nominal)	SRES costs at regional reference node ($/MWh, nominal)	Other environmental costs at regional reference node ($/MWh, nominal)	Environ mental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$102.99	$3.17	1.049	$5.20	$111.36	$9.64	$9.23	$1.80	$1.01	$21.68	$133.04
Endeavour - NSLP	$99.94	$3.01	1.055	$5.66	$108.61	$9.64	$9.23	$1.80	$1.14	$21.81	$130.42
Essential - NSLP	$94.69	$2.82	1.058	$5.66	$103.17	$9.64	$9.23	$1.80	$1.20	$21.87	$125.04
Ausgrid - CLP1	$76.74	$3.17	1.053	$4.24	$84.15	$9.64	$9.23	$1.80	$1.10	$21.77	$105.92
Ausgrid - CLP2	$72.46	$3.17	1.053	$4.01	$79.64	$9.64	$9.23	$1.80	$1.10	$21.77	$101.41
Endeavour - CLP	$90.44	$3.01	1.055	$5.14	$98.59	$9.64	$9.23	$1.80	$1.14	$21.81	$120.40
Essential - CLP	$87.08	$2.82	1.058	$5.21	$95.11	$9.64	$9.23	$1.80	$1.20	$21.87	$116.98
Energex - NSLP	$89.16	$3.18	1.065	$6.00	$98.34	$9.64	$9.23	$0.00	$1.23	$20.10	$118.44
Energex - CLP1	$64.91	$3.18	1.065	$4.43	$72.52	$9.64	$9.23	$0.00	$1.23	$20.10	$92.62
Energex - CLP2	$72.85	$3.18	1.065	$4.94	$80.97	$9.64	$9.23	$0.00	$1.23	$20.10	$101.07
SAPN - NSLP	$141.39	$6.55	1.110	$16.27	$164.21	$9.64	$9.23	$2.50	$2.35	$23.72	$187.93
SAPN - CLP	$92.23	$6.55	1.110	$10.87	$109.65	$9.64	$9.23	$2.50	$2.35	$23.72	$133.37

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.40 ESTIMATED TEC FOR 2020-21 FINAL DETERMINATION ($/MWH, NOMINAL)

Profile	WEC at regional reference node ($/MWh, nominal)	Other wholesale costs at regional reference node ($/MWh, nominal)	Network loss factor	Wholesale network losses ($/MWh, nominal)	Total wholesale costs at the customer terminal ($/MWh, nominal)	LRET costs at regional reference node ($/MWh, nominal)	SRES costs at regional reference node ($/MWh, nominal)	Other environmental costs at regional reference node ($/MWh, nominal)	Environ mental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid - NSLP	$100.92	$4.85	1.050	$5.29	$111.06	$4.95	$9.31	$2.09	$0.82	$17.17	$128.23
Endeavour - NSLP	$101.07	$4.65	1.062	$6.55	$112.27	$4.95	$9.31	$2.09	$1.01	$17.36	$129.63
Essential - NSLP	$93.84	$4.26	1.055	$5.40	$103.50	$4.95	$9.31	$2.09	$0.90	$17.25	$120.75
Ausgrid - CLP1	$65.44	$4.85	1.053	$3.73	$74.02	$4.95	$9.31	$2.09	$0.87	$17.22	$91.24
Ausgrid - CLP2	$63.63	$4.85	1.053	$3.63	$72.11	$4.95	$9.31	$2.09	$0.87	$17.22	$89.33
Endeavour - CLP	$93.20	$4.65	1.062	$6.07	$103.92	$4.95	$9.31	$2.09	$1.01	$17.36	$121.28
Essential - CLP	$79.06	$4.26	1.055	$4.58	$87.90	$4.95	$9.31	$2.09	$0.90	$17.25	$105.15
Energex - NSLP	$82.45	$3.94	1.059	$5.10	$91.49	$4.95	$9.31	$0.00	$0.84	$15.10	$106.59
Energex - CLP1	$64.32	$3.94	1.059	$4.03	$72.29	$4.95	$9.31	$0.00	$0.84	$15.10	$87.39
Energex - CLP2	$65.99	$3.94	1.059	$4.13	$74.06	$4.95	$9.31	$0.00	$0.84	$15.10	$89.16
SAPN - NSLP	$132.61	$6.49	1.108	$15.02	$154.12	$4.95	$9.31	$2.50	$1.81	$18.57	$172.69
SAPN - CLP	$77.58	$6.49	1.108	$9.08	$93.15	$4.95	$9.31	$2.50	$1.81	$18.57	$111.72

SOURCE: ACIL ALLEN ANALYSIS

A AEMC 2019 RESIDENTIAL ELECTRICITY PRICE TRENDS REPORT

The AEMC's report, *2019 Residential Electricity Price Trends,* was released in December 2019 (the AEMC report). ACIL Allen notes that 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 only.

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 unclear if the AEMC adjusts the historic NSLPs to take into account changes in the shape in the future due to further uptake of rooftop PV.
  - If the profiles are not adjusted this will result in different wholesale costs estimates (all other things equal).
  - It also appears that the AEMC aggregate the NSLPs within each region to produce a state-based NSLP.

— Spot market modelling:
  - AEMC appear to have used some form of planning model to introduce a total of about 3,500 MW of additional capacity into the market, beyond the capacity of identified committed projects, between 2019-20 and 2021-22. There is no information given as to the timing and location of this additional capacity.
  - ACIL Allen does not introduce any additional capacity into the market, beyond the capacity of identified committed projects, between 2019-20 and 2020-21, since there is insufficient lead time for a current development project to reach financial close and be constructed and operational by 2020-21.
  - Inclusion of additional capacity would change the results of the spot price modelling, all other things equal.
  - AEMC appears to use historic bids (offer curves) when undertaking its spot price modelling for 2019-20 and 2020-21. These appear to be adjusted for assumed changes in underlying costs (such as fuel prices). 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 5,000 MW of renewable capacity between now and 2020-21, as well as changes

in underlying costs). AEMC acknowledges that bidding behaviour may change in the future and therefore affect their results.
  - AEMC appears to run 32 simulations of the spot market for a given year (although it is not immediately clear whether there are 32 simulations of the spot market, or 8 simulations of the spot market coupled with 4 different NSLPs traces), compared with ACIL Allen's 539 simulations. The risk of the smaller number of simulations is that extreme events with a low probability of occurring are either overstated or understated.
- <u>Hedge portfolio:</u>
  - AEMC appear to use a portfolio of quarterly base, peak and cap hedges to cover the NSLP, as do ACIL Allen, but do not provide the mix of these products or the extent that the portfolio of hedges covers the NSLP profile.
- <u>Hedge or contract prices:</u>
  - AEMC use a 2-year build-up of hedges using ASX Energy contract price data up to 3 September 2019.
  - It appears AEMC's portfolio build-up is assumed to be completed by April 2020, as does ACIL Allen.
  - This means that 7 months of actual ASX Energy prices are unable to be included in the analysis for 2020-21 (with the six-month period being September 2019 to April 2020).
  - 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 7 months of missing ASX Energy data, it is not clear whether the AEMC have used their modelled spot price outcomes as a substitute for contract prices (noting this was the approach adopted in the 2018 price review report). This means that in deriving the final estimate of the contract prices for each quarterly product for 2020-21, AEMC is either missing about 50 per cent of ASX Energy trade volumes and corresponding prices, or is using their modelled spot prices to represent 50 per cent of trade volumes and contract prices.
  - Rather than prespecifying 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 that the cumulative shape in actual volume of trades can be quite different to an exponential curve.
  - 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.

A.2 Renewable energy target costs

No information is provided in the AEMC report as to how the LGC prices are derived. It appears the AEMC uses the STP values as provided by the Clean Energy Regulator when calculating the SRES costs.

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

ACILALLEN.COM.AU

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