ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

8 JUNE 2020

ESTIMATED ENERGY COSTS

2020-21 RETAIL TARIFFS

FOR USE BY THE QUEENSLAND COMPETITION AUTHORITY IN ITS FINAL DETERMINATION ON RETAIL ELECTRICITY TARIFFS

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ESTIMATED ENERGY COSTS FOR 2020-21 RETAILER TARIFFS: FINAL DETERMINATION, ACIL ALLEN, JUNE 2020

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C O N T E N T S

1 INTRODUCTION

ACIL Allen has been engaged by the Queensland Competition Authority (the QCA) to provide advice on the energy related costs likely to be incurred by a retailer to supply customers on notified retail prices for the 2020-21 regulatory period.

Retail prices generally consist of three components:

— network costs
— energy costs
— costs associated with retailing to end users.

ACIL Allen's engagement relates to the energy costs component only. In accordance with the Ministerial Delegation (the Delegation), and the Consultancy Terms of Reference (TOR) provided by the QCA, the methodology developed by ACIL Allen provides an estimate of energy costs to be incurred by a retailer to supply customers on notified prices for 2020-21. Although the QCA's determination is to apply only to the area outside of the Energex distribution area, the TOR specifically requests that ACIL Allen's analysis cover the same tariff classes as covered in the analyses for the 2013-14 to 2019-20 determinations, and therefore includes the load profiles for residential and small business customers in south east Queensland.

This report provides estimates of the energy costs for use by the QCA in its Final Determination.

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 QCA's *Draft Determination: Regulated retail electricity prices for 2020-21* (March 2020), where those submissions refer to the methodology used to estimate the cost of energy in regulated retail electricity prices.
— Chapter 4 summarises our derivation of the energy cost estimates.
— Finally, Appendix A summarises our high-level comparison with the AEMC's 2019 Residential Electricity Price Trends Report released in December 2019.

2

OVERVIEW OF APPROACH

2.1 Introduction

In preparing advice on the estimated energy costs, ACIL Allen is required to have regard to the actual costs of making, producing or supplying the goods or services which in this case are the customer retail services to be supplied to customers on notified prices for the tariff year 1 July 2020 to 30 June 2021.

In undertaking the task, ACIL Allen has not been asked to provide advice on:

— the effect that the price determination might have on competition in the Queensland retail market
— the Queensland Government uniform tariff policy
— time of use pricing
— any transitional arrangements that might be considered or required.

ACIL Allen understands that these matters will be considered by the QCA when making its Determination.

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.

2.3 Methodology

ACIL Allen's methodology follows the methodology used to provide advice to the QCA for the 2013-14 to 2019-20 determinations (refer to ACIL Allen's report for the 2014-15 Draft Determination and the 2014-15 Final Determination[2] for more details of the methodology).

The ACIL Allen methodology estimates costs from a retailing perspective. This includes wholesale energy market simulations to estimate expected pool costs and volatility and the hedging of the pool price risk by entering into electricity contracts with prices represented by the observable futures market data. Other energy costs are added to the wholesale energy costs and the total is then adjusted for network losses.

Demand profiles

The methodology is required to estimate the costs for following load profiles:

— NSLPs for the Energex and Ergon distribution networks

— controlled load profiles (CLPs) for the Energex distribution network.

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

TABLE 2.1 SOURCES OF LOAD DATA

Distribution Network	Load Type	Load Name	Source
Energex	NSLP	NSLP, ENERGEX	MSATS
Energex	CLP	QLDEGXCL31, ENERGEX	MSATS
Energex	CLP	QLDEGXCL33, ENERGEX	MSATS
Ergon	NSLP	NSLP, ERGON	MSATS

SOURCE:AEMO

ACIL Allen is aware that Energy Queensland has proposed three new controlled load network tariffs for 2020–25 in its latest Tariff Structure Statements (TSS):

— in the Energex area, a primary controlled load tariff for small business customers, where typical applications of this tariff will be single large loads such as irrigation pumps and motors (with individual NMIs), that can be interrupted as required by Energex.

— in the Ergon area, primary and secondary controlled load tariffs for SAC large customers, where these tariffs will be suitable for large customers where the nature of their operation (i.e. size of equipment, connection type, suitability for load control etc.) is similar/identical to that of SAC small customers on controlled load tariffs.

The terms and conditions for these tariffs will be set out in its annual pricing proposal (to be approved by the AER in late 2020).

ACIL Allen acknowledges that different tariffs may have different load profiles. However, the approach to estimating the WEC for a given tariff needs to be based on observable data. At this stage there is no information on the shape of the load associated with each of these new tariffs, nor how Energex and Ergon intend to manage these loads. Therefore, ACIL Allen is of the opinion that is it not possible to develop separate robust WEC estimates for these tariffs at this stage.

2.3.1 Wholesale energy costs - market-based approach

As with the 2013-14 to 2019-20 reviews, ACIL Allen continues to use the market hedging approach for estimating the WEC for 2020-21.

We have utilised our:

— stochastic demand model to develop 49 weather influenced simulations of hourly demand traces for each of the tariff profiles – using temperature data from 1970-71 to 2018-19 and demand data for 2016-17 to 2018-19

— stochastic outage model to develop 11 hourly power station availability simulations

— energy market models to run 539 simulations of hourly pool prices of the NEM using the stochastic demand traces and power station availabilities as inputs

— analysis of contract data to estimate contract prices

— hedge model taking the above analyses as inputs to estimate a distribution of hedged prices for each tariff class.

We have then analysed the distribution of outcomes produced by the above approach to provide a risk adjusted estimate of the WEC for each tariff class.

We have continued to rely on the Australian Energy Market Operator (AEMO) as a source for the various demand data required for the analysis. The QCA provided ACIL Allen with access to ASX Energy data, and OTC data from TFS Australia for the purpose of estimating contract prices.

The peak demand and energy forecasts for the demand profiles are referenced to the current AEMO demand forecasts for Queensland and take into account past trends and relationships between the NSLPs and the Queensland region demand. It is our assessment that the AEMO medium series demand projection for 2020-21 provided in AEMO's 2019 Electricity Statement of Opportunities (ESOO) is the most reasonable demand forecast for the purposes of this analysis.

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.

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

Table 2.2 provides a summary of the assumed changes to existing supply included in the 2020-21 market simulations.

TABLE 2.2 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 2.3 provides near term entrants that ACIL Allen considers committed projects for the 2020-21 simulations.

TABLE 2.3 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

Region	Name	Generation Technology	Capacity (MW)	Expected Entry
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
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

Region	Name	Generation Technology	Capacity (MW)	Expected Entry

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 2020 and 2021 calendar years, with the costs averaged to estimate the 2020-21 financial year costs.

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

— historical Large-scale Generation Certificate (LGC) market forward prices for 2020 and 2021 from brokers TFS[1]

— the published Renewable Power Percentage (RPP) for 2020 of 19.31 per cent, as published by the CER

— estimated RPP value for 2021 of 19.44 per cent[2]

— the binding Small-scale Technology Percentage (STP) for 2020 of 24.40 per cent, as published by the CER

— estimated STP value for 2021 of 22.15 per cent[3]

— CER clearing house price[4] for 2020 and 2021 for Small-scale Technology Certificates (STCs) of $40/MWh.

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.

[1] TFS data includes prices up to and including 8 May 2020.

[2] The estimated RPP value 2021 was estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2021.

[3] The STP value for 2021 was estimated using ACIL Allen's estimates of STC creations and liable acquisitions in 2021.

[4] 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.

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 Reports for Q4 2019 and Q1 2020 and ascribe RERT costs to the NEM regions of Victoria and New South Wales.

There are no costs ascribed to the Queensland region of the NEM for 2019-20.

2.3.4 Energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the Queensland 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 Energex and for the Ergon Energy east zone and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the wholesale energy cost estimates to incorporate losses.

The 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.

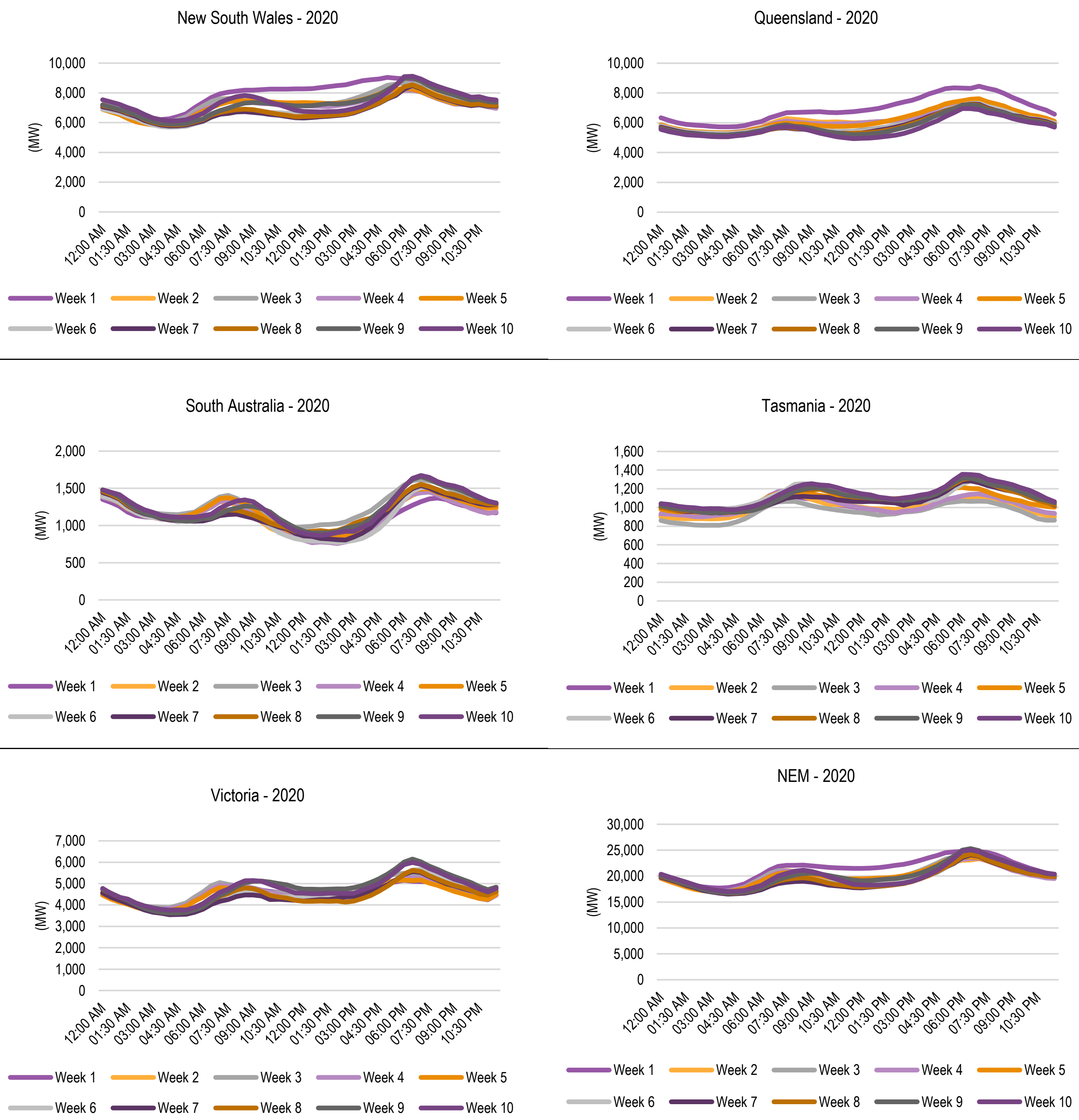
2.4 A note on COVID-19

The 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, April and the first nine days of May 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 from the second half of March onwards. 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 10 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.
    - In other words, the reduction in demand in 2020, when accounting for the change in temperature is actually less than it was in 2019.
    - 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.

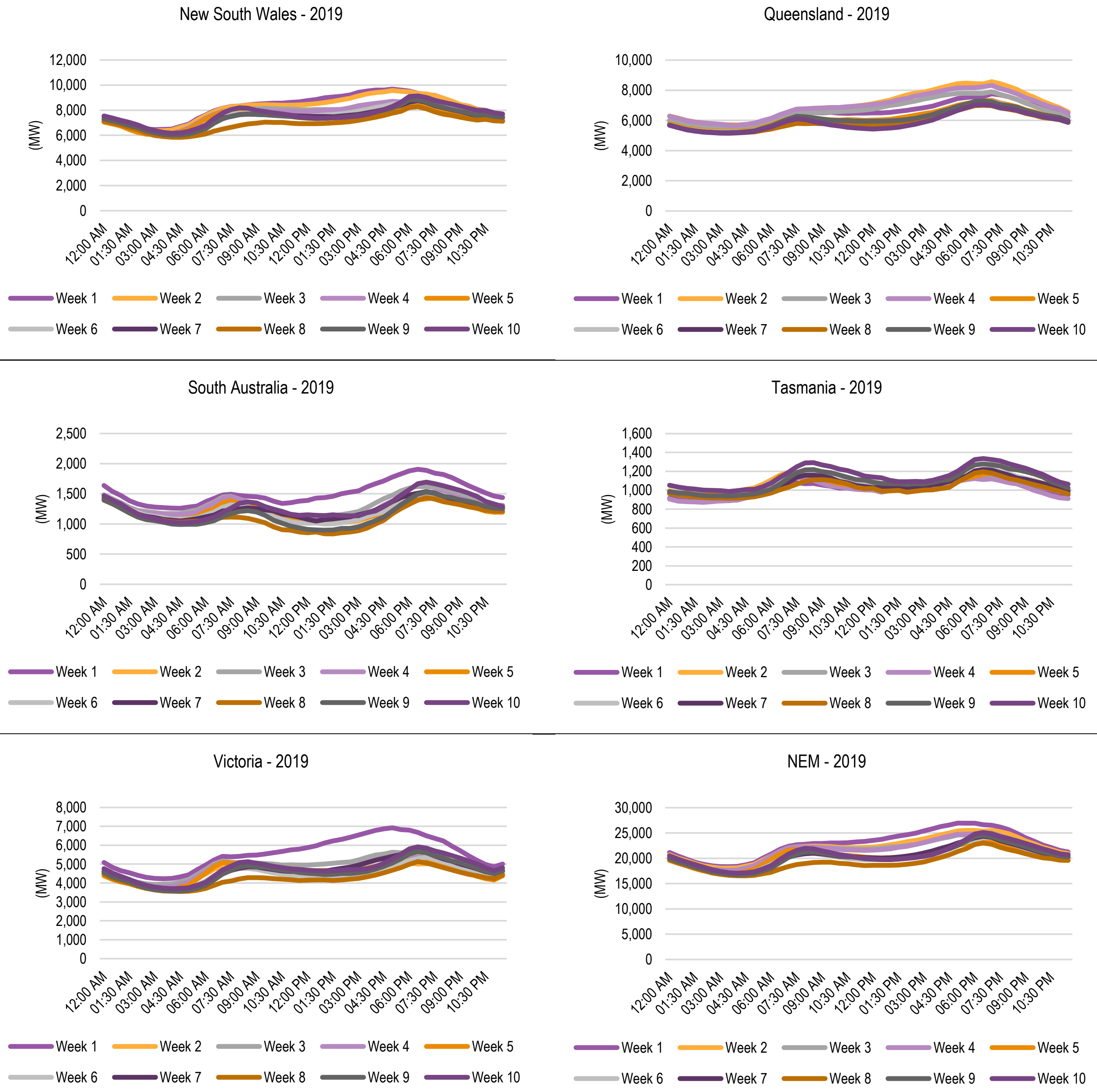
FIGURE 2.1 AVERAGE TIME OF DAY DEMAND (MW) BY REGION AND WEEK – 1 MARCH 2020 TO 9 MAY 2020



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 8 = 19 – 25 April 2020; Week 9 = 26 April – 2 May 2020; Week 10 = 3 – 9 May 2020 . Demand reported is scheduled and semi-scheduled generation requirements.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

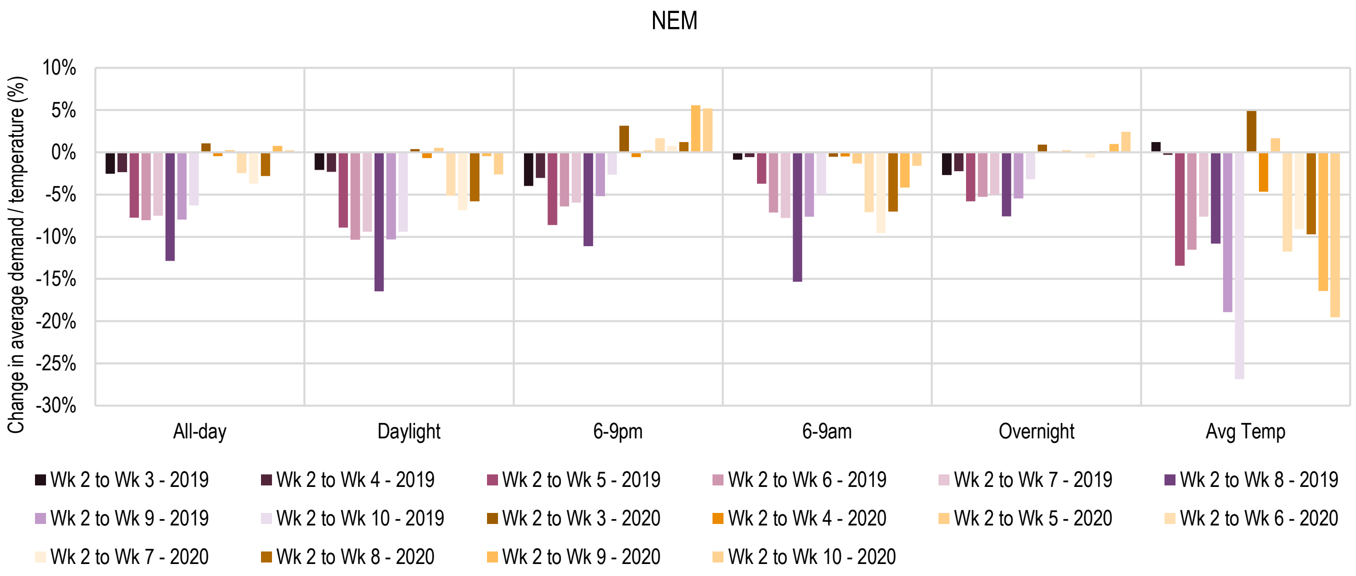
FIGURE 2.2 AVERAGE TIME OF DAY DEMAND (MW) BY REGION AND WEEK – 1 MARCH 2019 TO 9 MAY 2019



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 8 = 19 – 25 April 2019. Week 9 = 26 April – 2 May 2019; Week 10 = 3 – 9 May 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 SINCE THE WEEK OF 8-14 MARCH – 2019 AND 2020



Note: Week 1 = 1-7 March; Week 2 = 8-14 March; Week 3 = 15-21 March; Week 4 = 22-28 March; Week 5 = 29 March – 4 April; Week 6 = 5 – 11 April; Week 7 = 12 – 18 April; Week 7 = 19 – 25 April. 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 QCA forwarded to ACIL Allen a total of 13 submissions (including one confidential submission)[5] 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 costs
1	Bundaberg Regional Irrigators Group	Nil	Nil	Nil
2	CANEGROWERS	Yes	Nil	Nil
3	Confidential	Nil	Nil	Nil
4	COTA Queensland	Nil	Nil	Nil
5	Cotton Australia	Nil	Nil	Nil
6	Energy Queensland (EQL)	Yes	Nil	Nil
7	Kalamia Cane Growers Organisation	Nil	Nil	Nil
8	Mainstream Aquaculture Queensland	Yes	Nil	Nil
9	Pioneer Valley Water Co-operative	Nil	Nil	Nil
10	Queensland Council of Social Services (QCOSS)	Yes	Nil	Nil
11	Queensland Electricity Users Network (QEUN)	Yes	Nil	Nil
12	Queensland Consumers Association	Yes	Nil	Nil
13	Queensland Farmers Federation	Nil	Nil	Nil

Note: Yes = an issue was raised that required ACIL Allen's consideration
SOURCE: ACIL ALLEN ANALYSIS OF QCA SUPPLIED DOCUMENTS

[5] Details of the confidential submission have not been included in this report.

3.1 Wholesale energy cost

Most stakeholders support the current approach to estimating wholesale energy costs. Specifically, Energy Queensland (EQL) stated on page 6 of their submission:

Energy Queensland continues to support the QCA's approach to estimating wholesale energy costs, acknowledging the consistent approach which has been applied over a number of years. Energy Queensland is also supportive of the QCA's consultant, ACIL Allen, using the same methodology to estimate wholesale energy costs for both the QCA and the AER (in calculating the Default Market Offer prices).

Energy Queensland asserts that rooftop and large-scale solar PV can lead to low, and at times, negative pool prices. On page 7 of their submission Energy Queensland stated:

Energy Queensland remains of the view that extreme negative prices are a risk to market participants and deserve as much attention in market modelling as extreme high price events. Energy Queensland notes that Figure 4.15[6] of ACIL Allen's report on Estimated Energy Costs for the QCA's Final Determination for 2019-20 regulated retail electricity prices has not been provided in its report to the QCA for this year's Draft Determination. Energy Queensland requests that this figure again be provided to demonstrate the careful consideration of low and negative prices.

ACIL Allen notes that there has been an observable fall in the load factor in the actual NSLP for most DNSP areas in recent years due to an increase in penetration of rooftop solar PV panels – the increased penetration no longer reduces the peak demand (since the peak demand now occurs between 6:30pm and 8:30pm) for most NSLPs but continues to reduce the average metered demand throughout the middle of the day.

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 hedging costs will increase.

ACIL Allen agrees that there is likely to be an increase in the number of negative spot price outcomes due to the continued uptake of roof-top PV and development of large-scale utility PV. However, that spot prices can sometimes be negative does not make them special. During these periods, the hedging strategy is likely to result in a hedge position that is long relative to the physical demand of the NSLP. Hence, during these periods the retailer in effect incurs a cost equal to the difference between the spot price and the hedge price multiplied by the extent their hedge position is long. This holds true when either the spot price is negative or positive – providing the spot price is less than the hedge price.

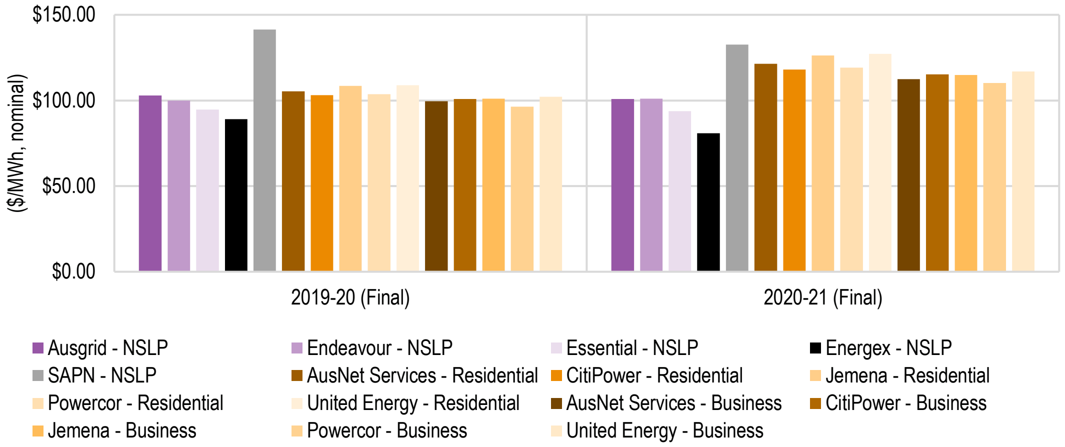
When spot prices are negative, they are likely to be equal to either the price floor in a renewable energy Power Purchase Agreement (PPA) (below which the renewable generator party of the PPA does not receive payment for its generation from its counterparty) or negative the LGC price. There are some PPAs that do not have price floors, in which case the renewable energy generator is indifferent to the spot price and hence may offer its generation into the spot market at the market price floor of -\$1,000/MWh. However, the trend in PPA terms in recent years is to include a price floor of around negative \$50-\$60/MWh.

Energy Queensland also asked that the equivalent of Figure 4.15 from ACIL Allen's report on Estimated Energy Costs for the QCA's Final Determination for 2019-20 be included for the latest determination – this is provided in Figure 4.13.

Mainstream Aquaculture on page one of its submission provide a comparison of quarterly base future prices by state as at September 2017, for contracts between quarter three 2017 and quarter two 2021. Mainstream Aquaculture then query why electricity costs in Queensland are 40 per cent higher than Victoria. It is unclear whether they are referring to the WEC or end user retail tariffs. In any case, the graph below confirms the WECs in Queensland are the lowest of all distribution zones for 2019-20 and 2020-21.

[6] Estimated Energy Costs for 2019-20 Retail Tariffs: Final Determination, ACIL Allen, May 2019, pg 22

FIGURE 3.1 COMPARISON OF WEC ($/MWH, NOMINAL) BY DISTRIBUTION ZONE



Note: WECs for the Victorian distribution zones correspond to the 2019 and 2020 calendar years.

SOURCE: QCA, AER, ESC

Although challenging to decipher, QEUN on pages 13 through to 20 of its submission makes an ex-post comparison between the WECs of previous determinations and actual market outcomes, and appear to suggest the WEC methodology is overstating the cost incurred by a prudent and efficient retailer in procuring wholesale electricity to meet its retail load (including its NSLP). We make the following observations regarding the pertinent points in the QEUN's submission:

— The QEUN compares the WEC with the Queensland time weighted spot price (TWP) (for a selection of corresponding determination years). This is not meaningful – the time weighted price is a simple average of the half-hourly spot prices and does not take account the shape of the load profile. If the NSLP was perfectly flat in shape, hour by hour across the entire year, then it would make sense to consider the TWP – but of course, this is not the case.

— If a retailer was to purchase all its energy requirements for the NSLP from the spot market, then a demand weighted price (DWP), which is the sum product of the half-hourly spot prices and corresponding NSLP demands divided by the sum of the demands, would be the appropriate measure.

— Figure 3.2 compares the Energex NSLP DWP and WEC for the past six determinations. The WEC is below the DWP for half the determination years - this is in stark contrast with the QEUN's unfortunate conclusions.

— That the WEC is not below the DWP for all years is not reason to dismiss the WEC estimation methodology or a retailer's prudent approach to hedging price risk. Figure 3.2 also shows that the volatility of the WEC is far less that of the DWP. A retailer, selling electricity to its retail customers at a fixed price will naturally want to minimise spot price risk. For example, if in 2016-17 a retailer purchased all its retail electricity load on the spot market then it would have paid 75 per cent more than if it adopted a hedging strategy similar to that used to estimate the WEC.

— A prudent retailer will not purchase all its electricity requirements on the spot market – the risk is too great. Unless of course, it was able to pass this risk directly onto consumers. This in turn would mean that consumers, including households, would face volatile, and largely unpredictable, electricity bills.

— The hedging strategy adopted when estimating the WEC seeks to minimise the spot price risk. This strategy, whilst maximising certainty, does not necessarily minimise cost. Or put another way, price certainty implicitly includes a premium.

By inference, the QEUN's analysis and commentary indirectly suggests that the DWP should be used instead of the WEC. For several reasons, this is not appropriate:

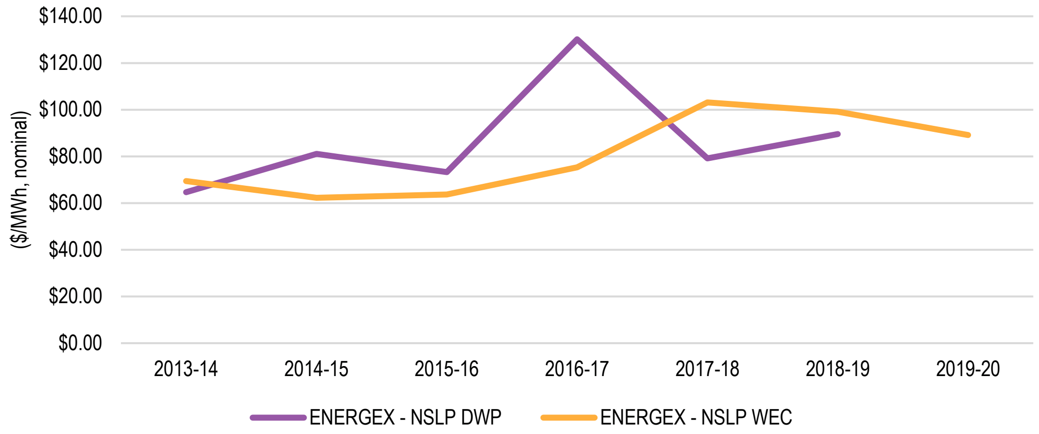
— The DWP is an ex-post outcome. Retailers retail electricity at a fixed ex-ante price, and the QCA is required to produce a price determination ex-ante.

— The resulting DWP will be a function of the underlying state of the market, and equally importantly, unpredictable stochastic drivers such as weather influenced demand and renewable energy resources, as well as power station availability. These stochastic drivers give rise to the volatility of spot price outcomes for a given year.

In practise, retailers do not purchase all their energy requirements at the spot price. They enter into hedging arrangements to minimise spot price risk. These hedging arrangements are built up over time ex-ante (usually over a two to three year period prior to the determination year), and as such, the cost of the hedging arrangements will reflect at that point in time the market's risk weighted view of the future spot price.

That contract prices end up being higher than the eventuating spot price simply means the conditions that eventuated were less than the market's risk weighted view ex-ante.

FIGURE 3.2 COMPARISON OF ENERGEX NSLP DEMAND WEIGHTED (SPOT) PRICE WITH WHOLESALE ELECTRICITY COST (WEC) ($/MWH, NOMINAL) FOR PREVIOUS DETERMINATIONS



Note: Due to the five-month lag in AEMO publishing the NSLP data, it is not meaningful to calculate the DWP for 2019-20.
SOURCE: ACIL ALLEN AND AEMO

3.2 COVID-19

Some stakeholders have raised the issue of the effects of COVID-19 pandemic on the cost of wholesale energy. Specifically, CANEGROWERS stated on page 3 of their submission:

The Australian coal and energy sector has seen the cost of electricity generation fall sharply since the onset of the COVID-19 pandemic. This reflects global reductions in prices for oil, coal and LNG as consumers and businesses modify their behaviour. Occurring since ACIL-Allen has prepared is cost of energy report, this new price environment is not reflected in the draft determination. CANEGROWERS calls on QCA to revise its cost of energy calculations to take into account the sharply lower global cost of energy.

Conversely, as part of the submission by Queensland Council of Social Services (QCOSS), page 7 of the Ertrog Consulting report stated:

In regard to COVID-19, our position agrees with the position taken by the AER in regard to the DMO prices for 2020-21: it is premature to adjust notified prices at this time to take into account COVID-19. There is no more certainty now about the impacts of COVID-19 than there was when the AER made its Final Determination on the DMO for 2020-21. Nor do we expect there to be any more certainty before the QCA completes its analysis for its Final Determination on notified prices for 2020-21. On that basis, we advise that the QCA should not attempt to make any further adjustment to its determination of notified prices for 2020-21 to take into account COVID-19.

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 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 (this is not to say they will not in the future). We have analysed the change in demand over the COVID-19 period in Section 2.4.
— 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.
— 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, largely locked in, wholesale energy costs – which could negate any decrease in contract prices.
— Although it may be the case that international export coal and gas prices have declined in recent times, they have not necessarily declined solely due to COVID-19. Indeed, coal and LNG prices have been in decline for about six to nine months. Further, the decline in export fuel prices needs to be considered in conjunction with the change in exchange rate (since export fuel prices are listed in US dollar terms). The Australian dollar has weekend against the US dollar over the same period thus offsetting the decline in fuel price to some extent.
— COVID-19 may also temporarily delay the commissioning of committed new investment wind and solar farms due to delays in delivery of project components.
— Finally, COVID-19 is likely to impact the uptake of rooftop PV. A decline in uptake has been reported over the past two months due to policies restricting movement of installers and availability of stock.
— In summary, COVID-19 may impact different segments of the NEM in different ways such that the effects cancel out to a large degree.

On page 12 of their submission, Queensland Electricity Users Network (QEUN) suggests that the Queensland Government implement the following measures in relation to estimating the cost of wholesale electricity amid the COVID-19 pandemic:

The Queensland Government caps wholesale electricity prices at $70/MWh and due to the unprecedented and unknown impacts of COVID19 engages two consultants (or a different consultant to the AER's Default Market Offer) to estimate the total cost of energy to be included in regulated retail prices for regional Queensland.

It is not appropriate for ACIL Allen to respond to this suggestion as the first part of the suggestion is a matter for the State Government, and the second part for the QCA. However, we note that ACIL Allen undertaking the WEC analysis for the AER in the DMO determination means that a larger, deeper and broader pool of stakeholders across a larger number of jurisdictions are able to scrutinise the WEC methodology.

As part of the submission by Queensland Council of Social Services (QCOSS), which is also supported by the Queensland Consumers Association, page 13 of the Etrog Consulting report stated:

In our response to the Interim Consultation Paper, we said:

– *As in previous years, we support the QCA's estimation of energy costs for 2020-21 being based on the application of the same methodology that was used in previous years.*

In its Draft Determination, the QCA has maintained this position, which we support. We also support this being maintained in the QCA's Final Determination.

We note that contract prices and other components of the energy cost calculation published after the set cut-off date are not taken into account in calculating energy costs.

Given that the QCA's Final Determination is being published later this year than in previous years (in June rather than in May), the QCA should consider setting the cut-off date this year to be later than in previous years – at least to the end of May, and preferably into June.

ACIL Allen agrees that accuracy is improved if the latest possible data is included in our analysis. The key input used in our analysis that is a function of the market data cut-off date are the contract prices and trade volumes, which we obtain from ASX Energy. For the Final Determination, the market data cut-off date has been extended to 8 May 2020.

ACIL Allen's approach assumes that a retailer builds their book of hedges ahead of the start of the DMO period. ACIL Allen uses all trades (generally 2-3 years) back to the first trade recorded by ASX Energy for the given product, which generally more closely reflect, in practice, how retailers build up their portfolio of hedging contracts over time – taking into account their evolving view on their market share and customer load.

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 2020-21.

4.1.1 Historic energy price levels

Figure 4.1 shows the average time of day pool (spot) price for the Queensland region of the NEM, and the average time of day load profiles for Queensland, the Energex NSLP, the Energex controlled load profiles (tariffs 31 and 33), and the Ergon NSLP for the past eight years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the tariffs.

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 Queensland. 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.

Prices in 2017-18 declined by about $20/MWh compared with 2016-17 to about $73/MWh (representing a decrease of just over 20 per cent). This decline is driven by a slight decrease in gas prices, the commissioning of just under 700 MW of solar and wind farms, the decline in coal costs in New South Wales coal fired power stations, and the return to service of Swanbank E.

Prices in 2018-19 increased by about $8/MWh compared with 2017-18 to about $80/MWh. This is largely driven by an increase in morning and evening peak prices due to an increase in gas prices, and an increase in prices at other times due to an increase in the export coal price (which affects NSW and some Queensland coal fired power stations), rather than an increase in price volatility.

Compared with 2018-19, wholesale spot prices to date in 2019-20 have decreased by about $25/MWh in Queensland. This is largely a result of the continued commissioning of large-scale renewable generation across the NEM, as well as a decline in gas prices due to a slightly better global supply outlook, which has meant LNG exporters have made more supply available to the domestic market due to depressed international prices. South-east Queensland temperature outcomes in January and February 2020 were comparatively milder than January and February 2019 – with temperature about equal to the long-term average. South-east Queensland rainfall over the same period in 2020 was above average, and in contrast to the dry summer of 2018-19.

In relation to each profile, we note the following:

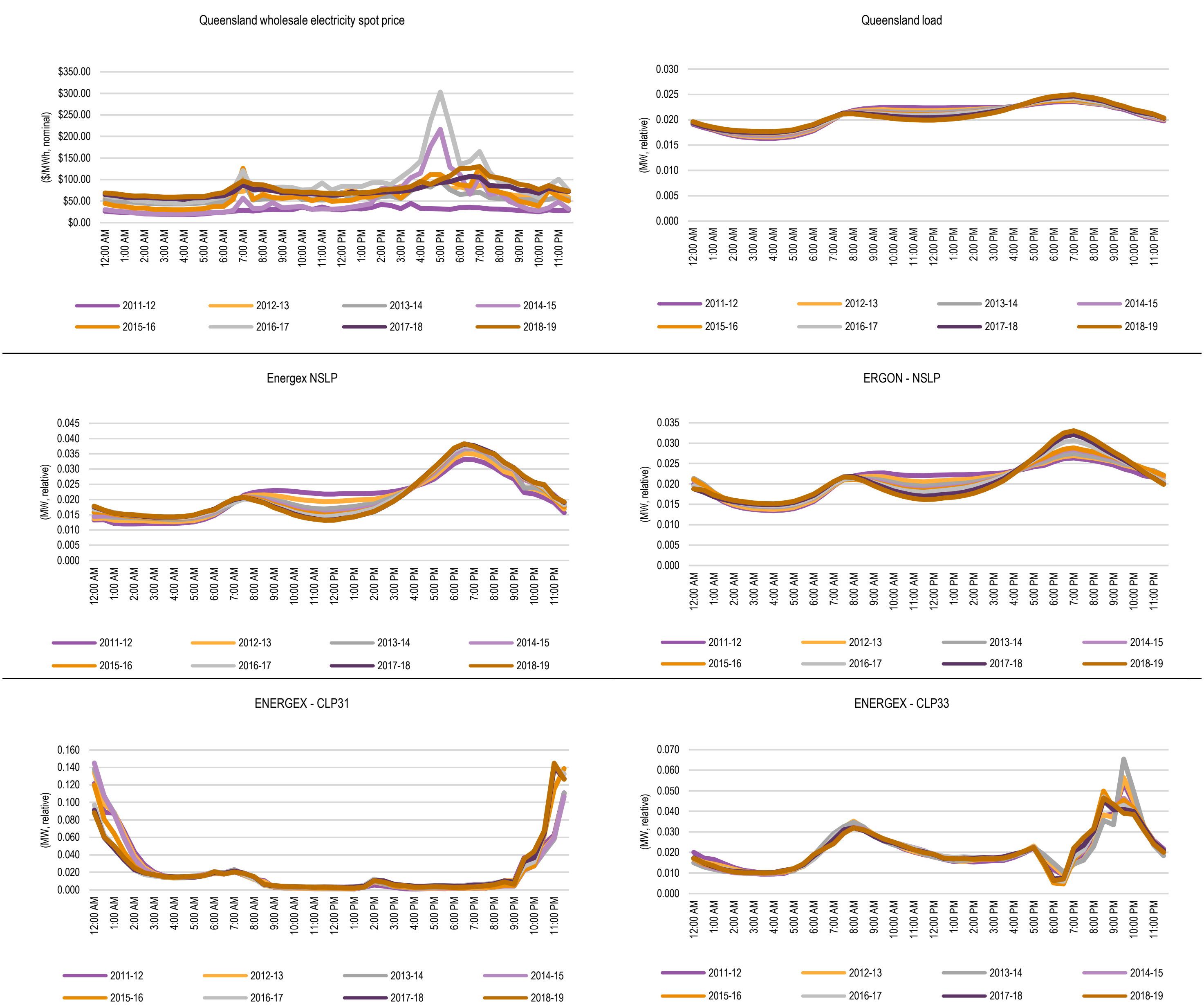
— The annual time of day price profile has been volatile over the past eight years – with the overall level and shape of the price profile changing from one year to the next. For example, in 2011-12 the time of day profile was very flat compared with 2014-15. In 2012-13 and 2013-14, prices increased largely because of the carbon tax. Between 2016-17 and 2018-19 price volatility has decreased – particularly during the evening peak periods. Prices have generally peaked in the afternoon and evening, whereas in some years there is also a morning peak. In short, the profile of prices varies from one year to the next – noting that these are the annual profiles (seasonal profiles are even more variable over time).

— The load profile of tariff 31 has been relatively consistent from one year to the next since 2011-12 – ramping up from about 9:30 pm, peaking at about midnight and then ramping down to about 3:00 am. This is inversely correlated with the price profile – with load higher at times of lower spot prices. This has resulted, on average, in a relatively low wholesale energy cost for tariff 31, compared with the other tariffs.

— The load profile of tariff 33 has been relatively consistent from one year to the next for most parts of the day. However, there was some volatility between 5:30 pm and 10:30 pm over the past few years. The load exhibits a morning peak at around 8:00 am – and prices also experience uplift around that time. The load also exhibits an evening peak at around 9:30 pm – but this varied from year to year (note that in 2014-15 and 2015-16 it tends to peak around 8:30 pm). Compared with tariff 31, the load profile of tariff 33 is weighted slightly more towards the daylight hours and the evening peak, and hence it is not surprising that its wholesale energy costs are higher than those of tariff 31.

— Over the past five years, the Energex NSLP load profile, and to a similar degree in more recent times, the Ergon NSLP, 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. The Energex NSLP load profile has a higher weighting towards the peak periods – particularly the evening peak and hence it is not surprising that the NSLP has the highest wholesale energy cost out of the two NSLP profiles.

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



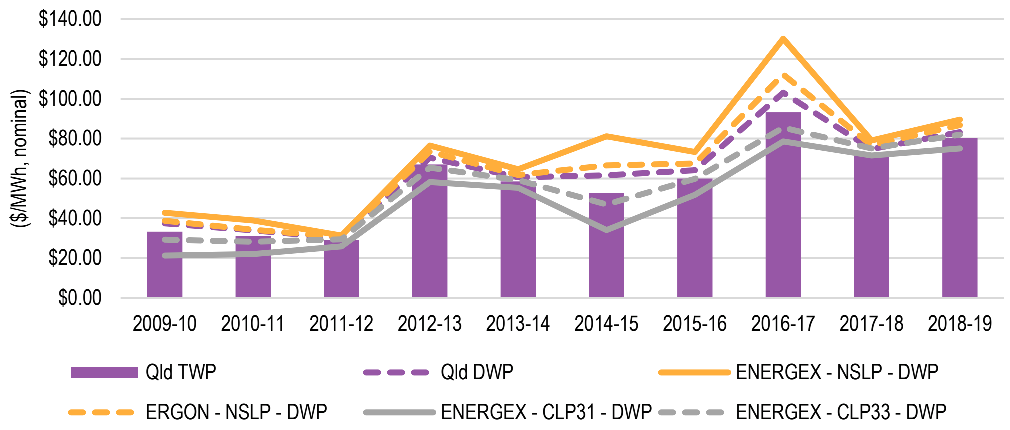
Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Figure 4.2 shows the actual annual demand weighted spot price (DWP) for each of the tariff loads compared with the time weighted average spot price in Queensland (TWP) over the past 10 years. As expected, the DWPs for tariffs 31 and 33 are below the DWP for the NSLPs in each year, with tariff 31 having the lowest price. Although the rank order in prices by tariff 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, 2017-18, and 2018-19, the relatively flatter half-hourly price profile resulted in the profiles having relatively similar wholesale spot prices. However, from 2014-15 and 2016-17, the increased price volatility across the afternoon period has resulted in the NSLP spot price diverging away from tariff 31 and 33. Conversely, the increase in off-peak spot prices in 2015-16 lifted the DWP of tariff 31 and 33 up towards that of the NSLP.

It is also worth noting that it has only been for four of the past 10 years that the control loads have noticeably lower DWPs when compared with the NSLPs. Certainly in 2017-18 the DWPs across all tariff classes were comparatively very similar. ACIL Allen raises this point as it is often questioned/noted in submissions that the wholesale energy costs for the control loads produced by our methodology are no longer substantially lower than those of the NSLPs. The control loads are subject to the DNSPs in that are used to manage network congestion – hence their shape is not purely a result of consumer behaviour.

FIGURE 4.2 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY TARIFF AND QUEENSLAND TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2018-19



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

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

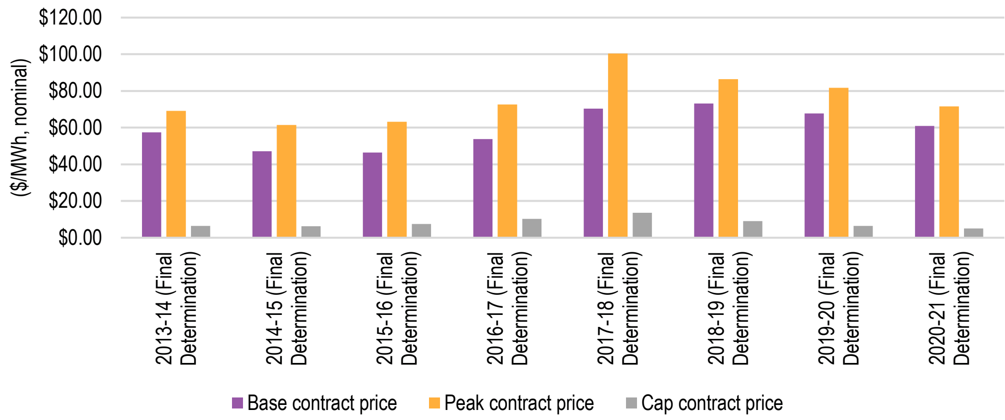
The volatility of spot prices (timing and incidence) in the Queensland region of the NEM provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) available to retailers does not really 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 tariffs year on year, as is shown in Figure 4.3.

The market modelling undertaken by ACIL Allen, and reported in this chapter, broadly aligns with the market's expectations of price outcomes in 2020-21. Compared with the 2019-20 Final Determination, futures contract prices for 2020-21, on an annualised trade weighted basis to date, have:

— decreased by about $6.90/MWh for base contracts
— decreased by about $10.10/MWh for peak contracts
— decreased by about $1.40/MWh for cap contracts.

The market is clearly expecting some softening in price outcomes due to the strong increase in renewable investment coming on-line in 2020 and 2021. About 5,200 MW of renewable investment will enter the NEM over the next 18 months – about 1,350 MW of which will be in Queensland. 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.

FIGURE 4.3 QUARTERLY BASE, PEAK AND CAP CONTRACT PRICES ($/MWH) – FINAL DETERMINATION 2020-21 AND PREVIOUS FINAL DETERMINATIONS



SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY DATA

4.2 Estimation of the Wholesale Energy Cost

4.2.1 Estimating contract prices

Contract prices for Queensland were estimated using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed up until 8 May 2020 inclusive.

Table 4.1 shows the estimated quarterly swap and cap contract prices for the 2020-21 Final Determination and compares them with the estimates under the 2019-20 Final Determination.

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

	Q3	Q4	Q1	Q2
		Final Determination 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
		Final Determination 2020-21		
Base	$58.16	$60.21	$73.12	$52.10
Peak	$68.15	$68.71	$88.81	$60.89
Cap	$2.18	$3.60	$12.16	$2.48
		Percentage change from 2019-20 to 2020-21		
Base	-15%	-6%	-9%	-12%
Peak	-10%	-5%	-17%	-16%
Cap	-24%	-28%	-18%	-20%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 8 MAY 2020

Trade weighted base, peak and cap contract prices for 2020-21 are on average 10 per cent, 12 per cent and 21 per cent lower than 2019-20, respectively.

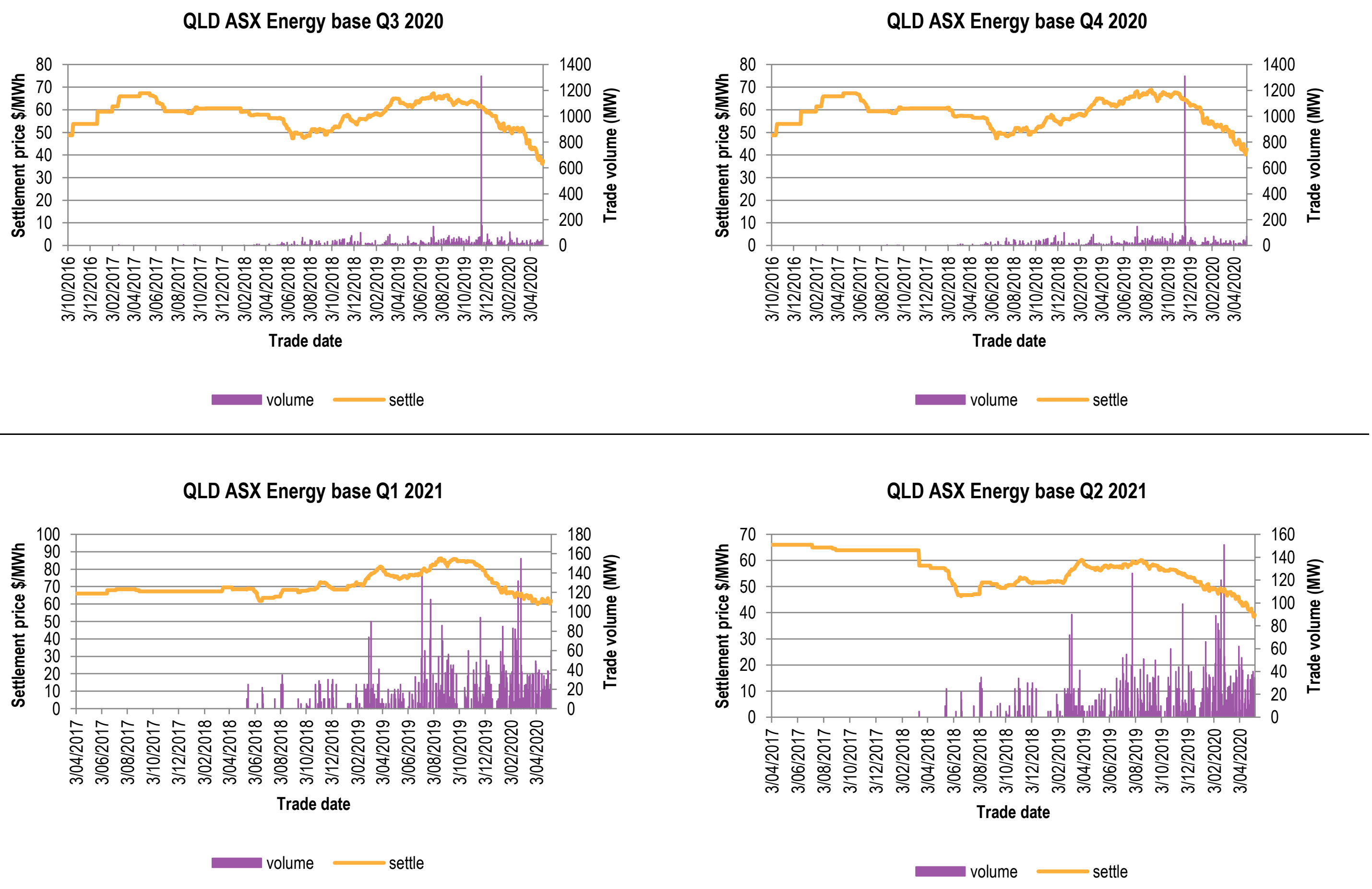
The lower base, peak and cap contract prices reflect the market's expectation that both the underlying price and price volatility will reduce in 2020-21 due to the continued commissioning of new renewable capacity.

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 ASX Energy quarterly base futures, peak futures and cap contracts up to 8 May 2020. Trade volumes up to 8 May 2020 inclusive are:

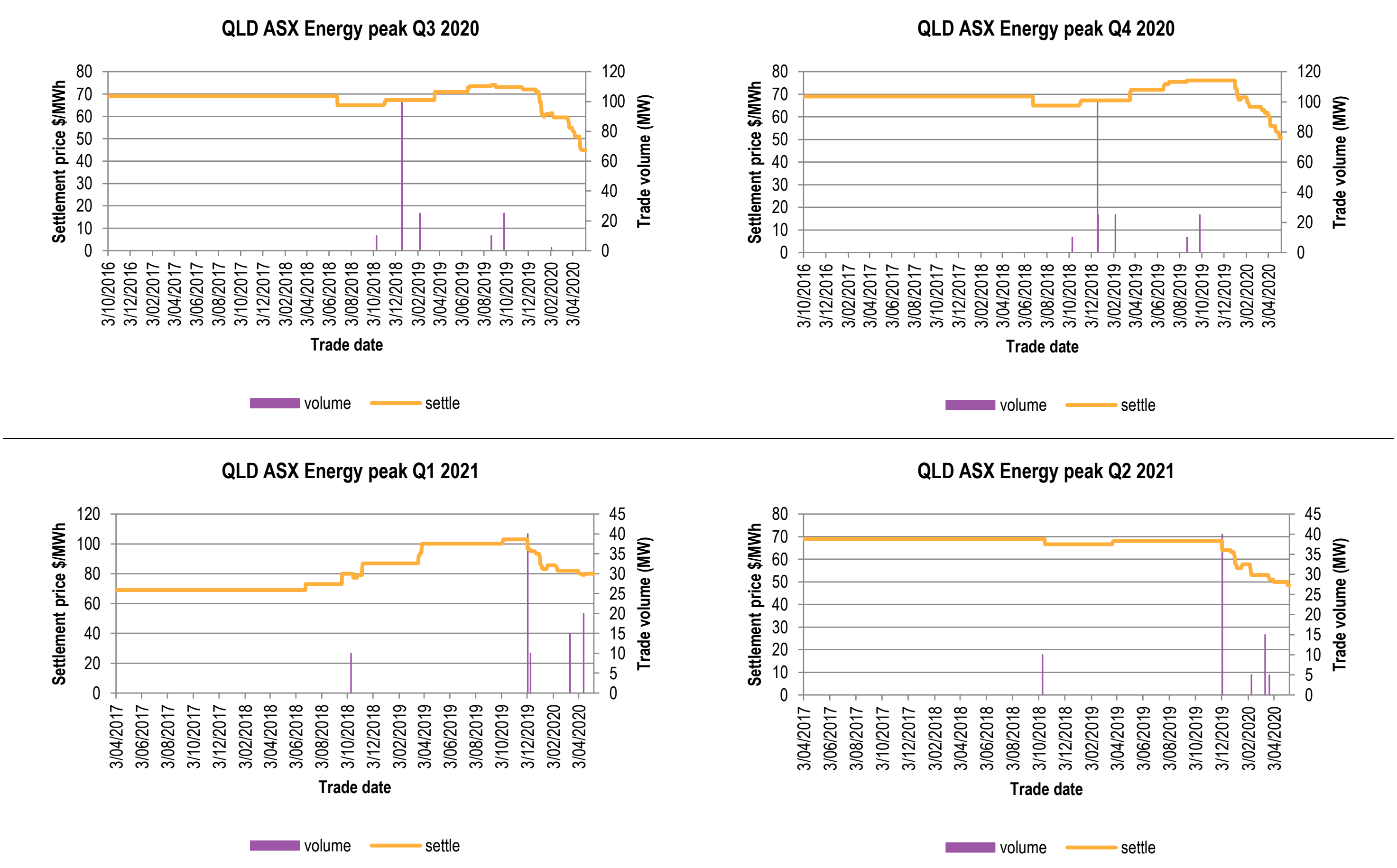
— Base futures have traded strongly, with total volumes of 8,786 MW (Q3 2020), 8,647 MW (Q4 2020), 6,260 MW (Q1 2021), and 5,588 MW (Q2 2021).
— Peak futures have also traded strongly with 197 MW (Q3 2020), 195 MW (Q4 2020), 95 MW (Q1 2021) and 75 MW (Q2 2021).
— Cap contract trade volumes have also traded strongly with 1,130 MW (Q3 2020), 923 MW (Q4 2020), 888 MW (Q1 2021) and 316 MW (Q2 2021).

FIGURE 4.4 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY BASE FUTURES



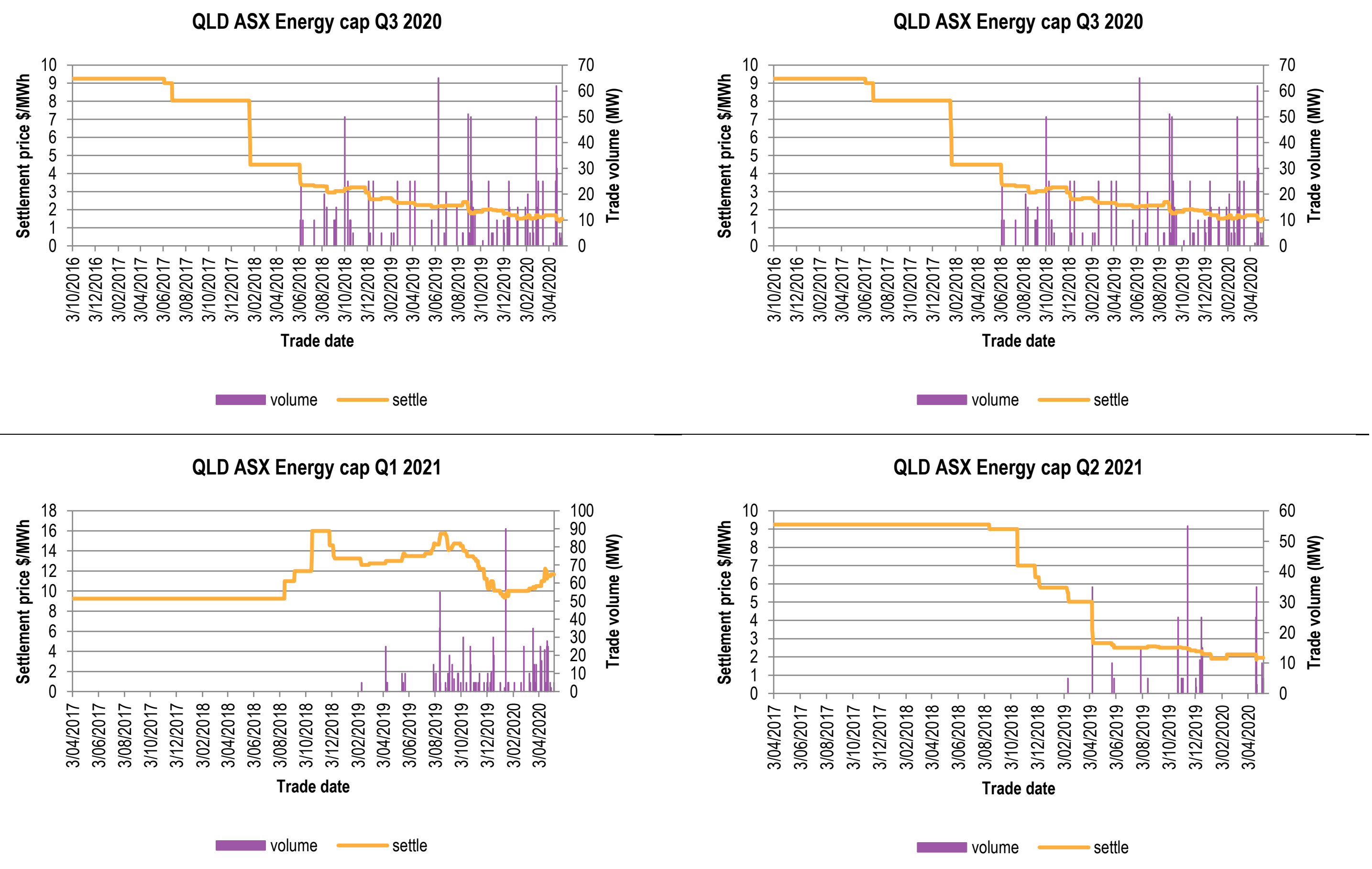
SOURCE: ASX ENERGY DATA UP TO 8 MAY 2020

FIGURE 4.5 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY PEAK FUTURES



SOURCE: ASX ENERGY DATA UP TO 8 MAY 2020

FIGURE 4.6 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY $300 CAP CONTRACTS



SOURCE: ASX ENERGY DATA UP TO 8 MAY 2020

4.2.2 Estimating wholesale spot prices

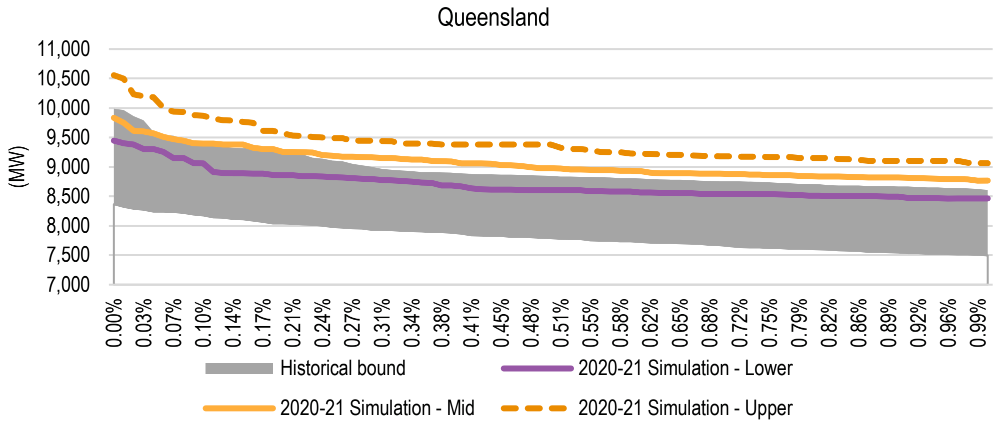
ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for 2020-21 for the 539 simulations (49 demand and 11 outage sets).

Figure 4.7 shows the range of the upper one percent segment of the demand duration curves for the 49 simulated Queensland demand sets resulting from the methodology, along with the 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[7]. 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 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.

[7] 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.

FIGURE 4.7 TOP ONE PERCENT HOURLY DEMANDS – QUEENSLAND

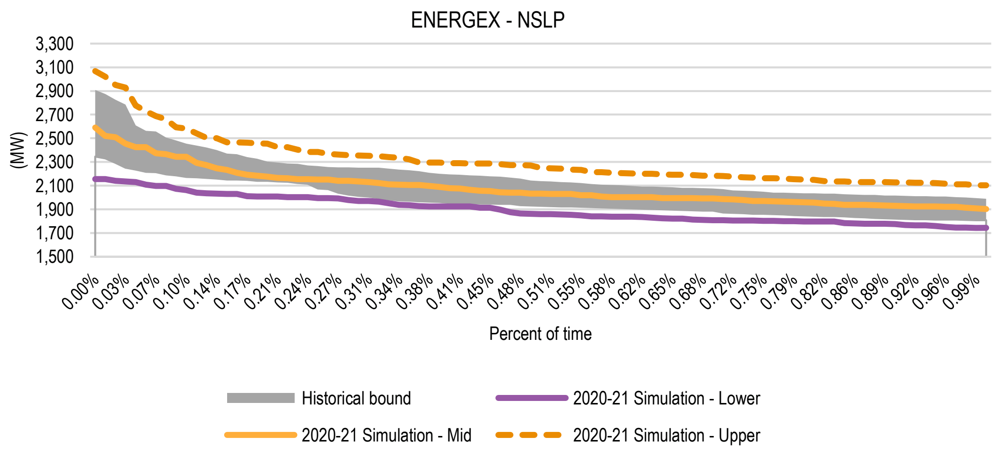


SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

Figure 4.8 shows the range of the simulated Energex NSLP demand envelopes recent outcomes and covers an average range of about 500 MW across the top one percent of hours. This variation results in the annual load factor[8] of the 2020-21 simulated demand sets ranging between 26 percent and 35 percent compared with a range of 43 percent to 29 percent for the actual NSLP between 2008-09 and 2018-19 (as shown in Figure 4.9). 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 – the increased penetration no longer reduces the peak demand (since the peak demand now occurs between 6:30pm and 8:30pm) but continues to reduce the average metered demand throughout the middle of the day.

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.

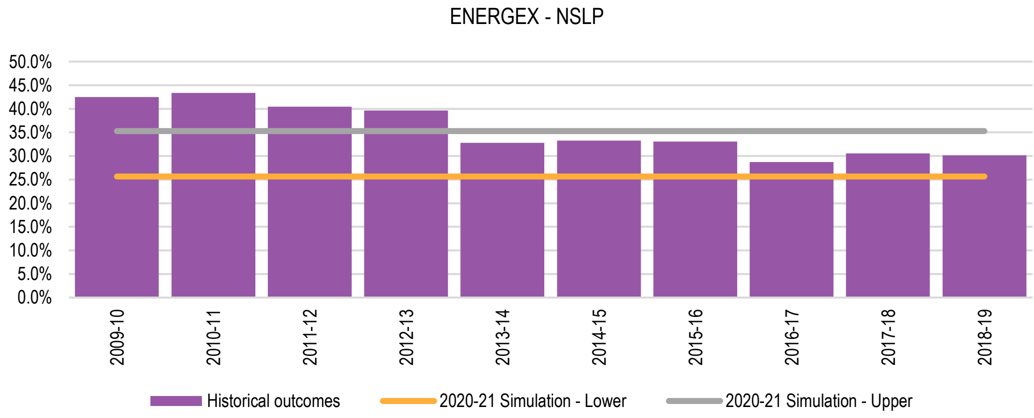
FIGURE 4.8 TOP ONE PERCENT HOURLY DEMANDS – ENERGEX NSLP



SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

[8] 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.

FIGURE 4.9 COMPARISON OF LOAD FACTOR OF SIMULATED HOURLY DEMAND DURATION CURVES FOR ENERGEX NSLP AND HISTORICAL OUTCOMES



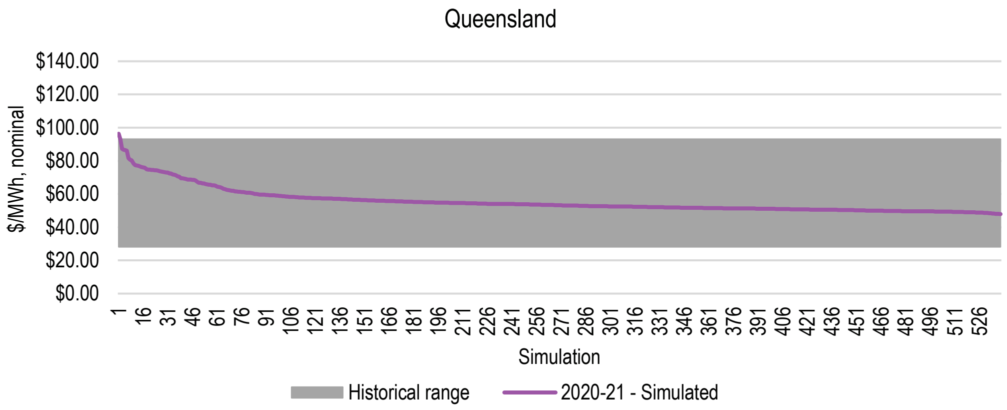
SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

The modelled annual time weighted pool prices (TWP) for Queensland in 2020-21 from the 539 simulations range from a low of $47.91/MWh to a high of $96.32/MWh. This compares with the lowest recorded Queensland TWP in the last 18 years of $28.12/MWh in 2005-06 to the highest of $93.13/MWh in 2016-17. The average TWP simulated for 2020-21 is $55.60/MWh – about 30 per cent less than the actual 2018-19 outcomes.

Figure 4.10 compares the modelled annual Queensland TWP for the 539 simulations for 2020-21 with the Queensland 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 relative to pre-LNG export facility levels, 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, 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 below the historic upper bound of actual outcomes. This is not surprising – price volatility in the market in 2020-21 is projected to be lower due to the large amount of capacity entering the market. Although it is generally stated that renewable capacity is intermittent and therefore may contribute to an increase in price volatility, the sheer increase in capacity entering the market in 2020 and 2021 outweighs this feature.

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.

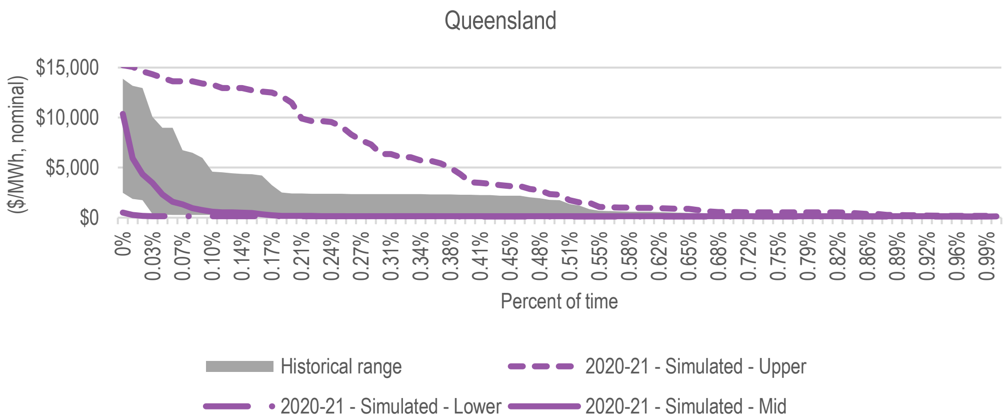
FIGURE 4.10 ANNUAL TWP FOR QUEENSLAND FOR 539 SIMULATIONS FOR 2020-21 COMPARED WITH ACTUAL ANNUAL OUTCOMES IN PAST YEARS



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

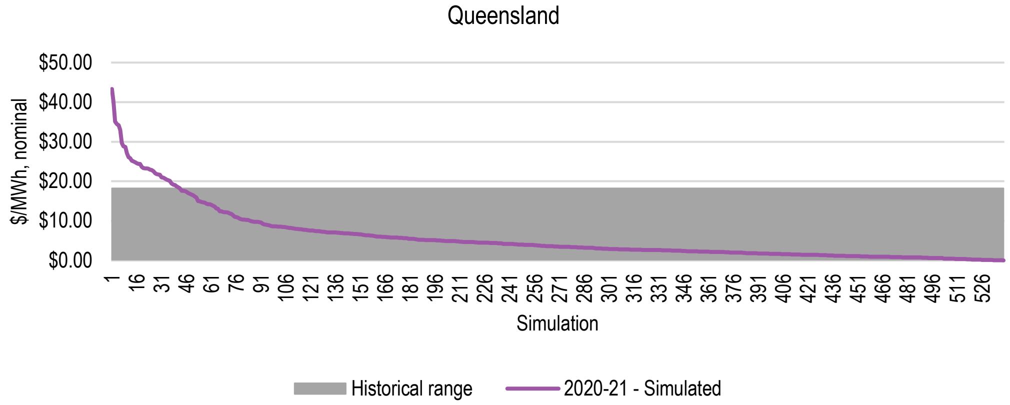
FIGURE 4.11 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR 2020-21 FOR QUEENSLAND AND HISTORICAL OUTCOMES



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 4.12.

FIGURE 4.12 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND TWP BY PRICES ABOVE $300/MWH FOR QUEENSLAND IN 2020-21 FOR 539 SIMULATIONS COMPARED WITH ACTUAL OUTCOMES IN PAST YEARS

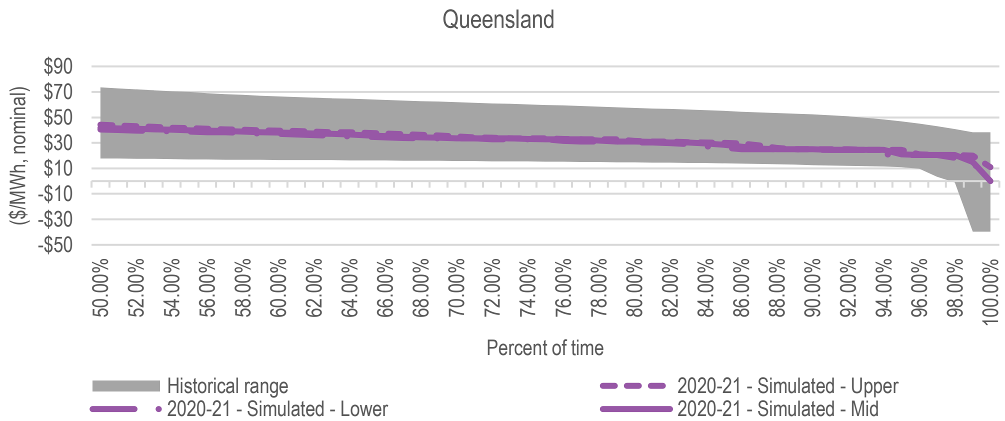


SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

Figure 4.13 compares the lower 50 per cent of hourly prices in the simulations with historical spot prices. Figure 4.14 compares the annual average time of day prices in the simulations with historical time of day spot prices. The continued increase in rooftop PV penetration and development of utility scale solar is projected to reduce price outcomes in 2020-21 during daylight hours and also the volatility in price outcomes during daylight hours.

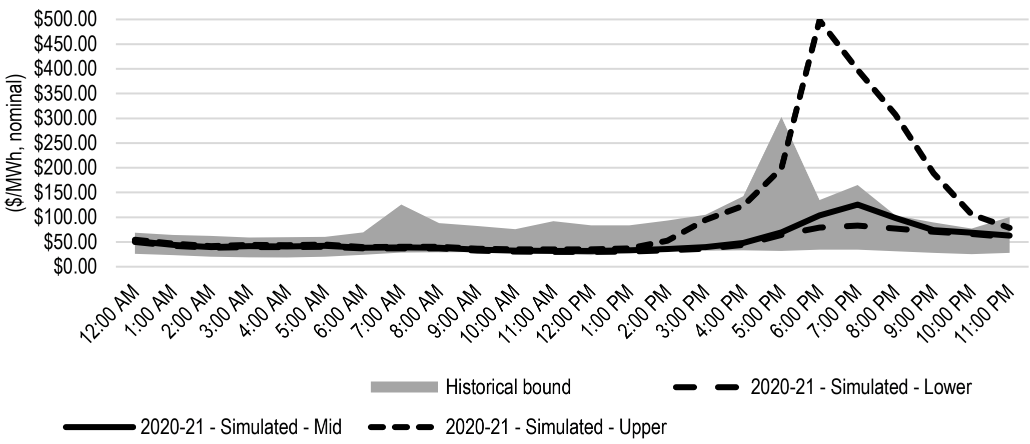
Simulated prices during daylight hours for 2020-21 are on average around $40/MWh – well below the annualised base contract price of about $61/MWh (as shown in Figure 4.15). Indeed, simulated prices during daylight hours are slightly lower than prices between 1am and 4am (historically the period of lowest price outcomes prior to the development of utility scale solar). During these periods, retailers will be making hedge difference payments.

FIGURE 4.13 COMPARISON OF LOWER 50 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND AND HISTORICAL OUTCOMES



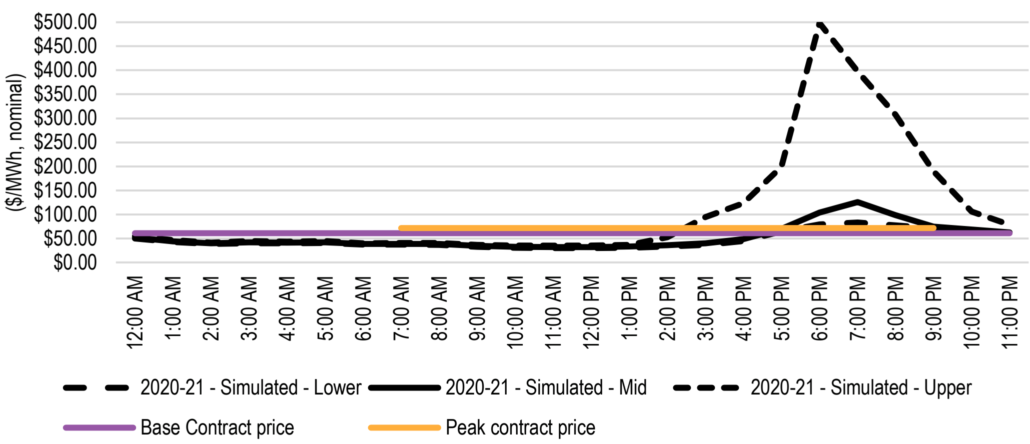
SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

FIGURE 4.14 COMPARISON OF ANNUAL AVERAGE TIME OF DAY SIMULATED HOURLY PRICE CURVES FOR QUEENSLAND AND HISTORICAL OUTCOMES



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

FIGURE 4.15 COMPARISON OF ANNUAL AVERAGE TIME OF DAY SIMULATED HOURLY PRICE CURVES FOR QUEENSLAND AND CONTRACT PRICES



Note: Quarterly trade weighted contact prices from Section 4.2.1 have been annualised

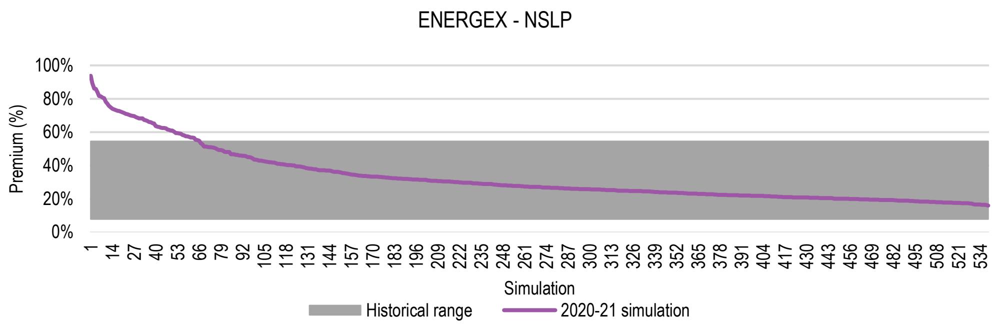
SOURCE: ASX ENERGY AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

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 Queensland 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 Queensland demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the Energex NSLP with the Queensland TWP. Figure 4.16 shows that, for the past 19 financial years, the DWP for the Energex NSLP as a percentage premium over the Queensland TWP has varied from a low of 8 percent in 2011-12 and 2017-18 to a high of 54 percent in 2014-15. 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 4.16 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 539 simulations is sound.

FIGURE 4.16 ANNUAL DWP FOR ENERGEX NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR QUEENSLAND FOR 539 SIMULATIONS FOR 2020-21 COMPARED WITH ACTUAL OUTCOMES IN PAST YEARS



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

ACIL Allen is satisfied the modelled Queensland pool prices from the 539 simulations cover the range of expected price outcomes for 2020-21 in terms of annual averages and distributions. These comparisons clearly show that the 49 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future 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 are calculated for each settlement class for each quarter as follows:

— The base contract volume is set to equal the 60th 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 70th percentile of the peak period hourly demands across all 49 demand sets minus the base contract volumes for the quarter.

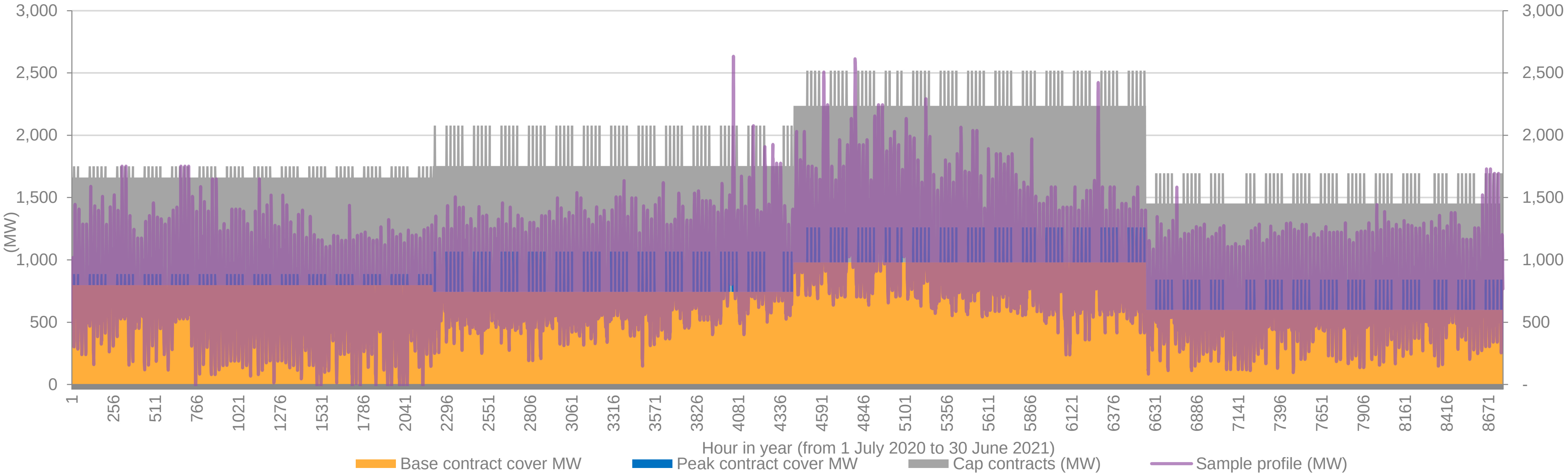
— The cap contract volume is set at 100 per cent of the median of the annual peak demands across the 49 demand sets minus the base and peak contract volumes.

The settings for the optimal contract strategy are slightly lower than those adopted for the 2019-20 determination – reflecting the continued carving out of demand during daylight hours due to the continued uptake of rooftop PV.

In other words, the same hourly hedge volumes (in MW terms) apply to each of the 49 demand sets for a given settlement class, 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 temperature 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 4.17.

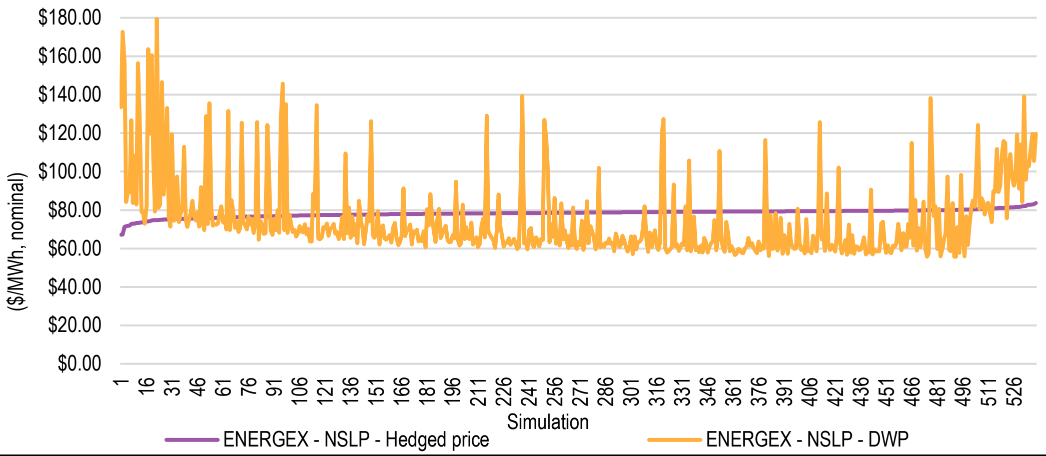
FIGURE 4.17 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 539 SIMULATIONS FOR 2020-21 FOR ENERGEX NSLP



SOURCE: ACIL ALLEN

Figure 4.18 shows that, by using the above contracting strategies, the variation in the annual hedged price for the 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 4.18 ANNUAL HEDGED PRICE AND DWP ($/MWH, NOMINAL) FOR ENERGEX NSLP 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 tariff class for the 2020-21 Final Determination are shown in Table 4.2.

TABLE 4.2 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2020-21 AT THE QUEENSLAND REFERENCE NODE

Settlement classes	2019-20 – Final Determination	2020-21 – Final Determination	Change from 2019-20 to 2019-20 (%)
Energex - NSLP - residential and small business	$89.16	$80.90	-9.26%
Energex - Controlled load tariff 9000 (31)	$64.91	$63.49	-2.19%
Energex - Controlled load tariff 9100 (33)	$72.85	$65.35	-10.30%
Energex - NSLP - unmetered supply	$89.16	$80.90	-9.26%
Ergon Energy - NSLP - CAC and ICC	$75.58	$72.41	-4.19%
Ergon Energy - NSLP - SAC demand and street lighting	$75.58	$72.41	-4.19%

SOURCE: ACIL ALLEN ANALYSIS

Compared with the 2019-20 Final Determination, the estimated WEC for 2020-21 for the Energex NSLP has decreased by about $8.30/MWh, decreased by about $3.20/MWh for the Ergon NSLP, decreased by about $7.50/MWh for control load tariff 33, and decreased by about $1.40/MWh for control load tariff 31.

The decrease in estimated WEC for the Energex NSLP reflects the projected decrease in price in Queensland and other regions of the NEM due to the expected continued entry of around renewable investment over the next 18 months, and softening of gas prices. The WEC for the Ergon NSLP decreases, but not be the same extent as the Energex NSLP. This is due to the projected increase in rooftop PV installations in the Ergon area over the next 18 months increasing the peakiness of the load profile more so than in the Energex area.

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

The change in WEC of the CLPs is reflecting the change in shape of the load profiles. Control load tariff 31 has about 65 per cent of its load requirements occurring between 10pm and 2am at night, and our modelling is suggesting that prices during these periods are not declining (given the extent of rooftop and utility scale investment and a fully year's operation of Wivenhoe do not reduce prices during these periods).

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[9]) 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 2020 and 2021 calendar years, with the costs averaged to estimate the 2020-21 financial year costs.

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

— historical Large-scale Generation Certificate (LGC) market forward prices for 2020 and 2021 from brokers TFS[10]
— the Renewable Power Percentage (RPP) for 2020 of 19.31 per cent, as published by the CER
— the estimated RPP value for 2021 of 19.44 per cent[11]
— the binding Small-scale Technology Percentage (STP) for 2020 of 24.4 per cent, as published by the CER
— estimated STP value for 2021 of 22.15 per cent[12]
— CER clearing house price[13] 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.

[9] 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.
[10] TFS data includes prices up to and including 8 May 2020.
[11] The RPP value for 2021 was estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2021.
[12] The STP value for 2021 was estimated using ACIL Allen's estimates of STC creations and liable acquisitions in 2021.
[13] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

The LGC price used in assessing the cost of the scheme for 2020-21 is found by taking the trade-weighted average of the forward prices for the 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 4.19). The average LGC prices calculated from the TFS data are $31.75/MWh for 2020 and $19.82/MWh for 2021.

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 between 2019 and 2021
- 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 4.19 LGC PRICES FOR 2020 AND 2021 ($/LGC, NOMINAL)

SOURCE: TFS AND ACIL ALLEN ANALYSIS

The published 2020 RPP value of 19.31 per cent has been set by the CER in March 2020.

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 is also used in the denominator of the 2021 STP estimate.

Key elements of the 2021 RPP estimation are shown in Table 4.3.

TABLE 4.3 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 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 $4.99/MWh in 2020-21 as shown in Table 4.4.

TABLE 4.4 ESTIMATED COST OF LRET – 2020-21

	2020	2021	Cost of LRET 2020-21
RPP %	19.31%	19.44%	
Average LGC price ($/LGC, nominal)	$31.75	$19.82	
Cost of LRET ($/MWh, nominal)	$6.13	$3.85	$4.99

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 2020-21.

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 4.5.

TABLE 4.5 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: CER AND ACIL ALLEN ANALYSIS

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2020-21 as set out in Table 4.6.

Since the 2019-20 Final Determination, the cost of LRET has almost halved, driven by lower LGC prices in 2020-21 and the cost of SRES has increased by over 28 per cent, driven by higher than expected installations in 2020 and 2021.

TABLE 4.6 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH, NOMINAL)

	2019-20 Final Determination	2020-21 Final Determination	Change
LRET	$9.38	$4.99	($4.39)
SRES	$7.26	$9.31	$2.05
Total	$16.64	$14.30	($2.34)

4.4 Estimation of other energy costs

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

— Market fees and charges including:

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

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the National Transmission Planner (NTP) and the Energy Consumers Australia (ECA).[14]

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2019-20*, the fees for 2020-21 are $0.71/MWh. The breakdown of total fees is shown in Table 4.7 and compared to the 2019-20 Final Determination.

TABLE 4.7 NEM MANAGEMENT FEES ($/MWH, NOMINAL)

Cost category	2019-20 Final Determination	2020-21 Final Determination
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.

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.[15]

TABLE 4.8 ANCILLARY SERVICES COSTS

Cost category	2019-20 Final Determination	2020-21 Final Determination
Ancillary services costs	$0.37	$1.53

SOURCE:AEMO

4.4.3 Prudential costs

Prudential costs have been calculated for the Energex and Ergon NSLP. The prudential costs for the Energex NSLP are then used as a proxy for prudential costs for the Energex controlled load profiles.

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

[14] ECA and FRC 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 estimates, therefore ACIL Allen has used DNSP customer numbers to estimate the cost of ECA and FRC requirements in $/MWh terms.

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

— 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 4.9 for each season for Energex NSLP gives an estimated MCL of $6,730.

However, as this applies for a rolling 42 days it actually covers 42 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh in the Energex NSLP is $6,730/42 = $160.24/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 $160.24 gives $0.46/MWh for Energex NSLP, as shown in Table 4.9**.**

TABLE 4.9 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

The components of the AEMO prudential costs for the Ergon NSLP are shown in Table 4.10. The estimated AEMO prudential costs for the Ergon NSLP are $0.35/MWh.

TABLE 4.10 AEMO PRUDENTIAL COSTS FOR ERGON NSLP – 2020-21

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$81.16	$45.94	$52.47
Participant Risk Adjustment Factor	1.2076	1.1158	1.1304
OS Volatility factor	1.62	1.28	1.35
PM Volatility factor	3.10	1.79	2.07
OSL	$6,718	$2,669	$3,278

Factor	Summer	Winter	Shoulder
PML	$1,344	$534	$656
MCL	$8,061	$3,202	$3,933
Average MCL		$5,055	
AEMO prudential cost ($/MWh, nominal)		**$0.35**	

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 0.25 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

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

— the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 8 percent on average for a base contract, 14 percent for a peak contract and 19 percent for a cap contract

— the intra monthly spread charge currently set at $12,300 for a base contract of 1 MW for a quarter, $13,600 for a peak contract and $5,900 for a cap contract

— the spot isolation rate currently set at $1,500 for a base contract, $1,500 for a peak contract and $600 for a cap contract.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter (rounded up) as shown for Queensland region in Table 4.11. 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 0.25 per cent return on cash lodged with the clearing (giving a net funding cost of 6.55 percent) results in the prudential cost per MWh for each contract type.

Average initial margins for Queensland using the average contract prices and initial margin parameters results in a prudential cost per MWh for each contract type as shown in Table 4.11.

TABLE 4.11 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$60.85	$25,000	$0.75
Peak	$71.58	$25,000	$1.74
Cap	$5.07	$9,000	$0.27

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 the Energex 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 as shown in Table 4.12. The same process was undertaken for the Ergon NSLP and is summarised in Table 4.13.

TABLE 4.12 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	$0.75	0.9931	$0.74
Peak	$1.74	0.1156	$0.20
Cap	$0.27	1.2956	$0.35
Total cost		**$1.29**	

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.13 HEDGE PRUDENTIAL FUNDING COSTS FOR ERGON NSLP – 2020-21

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$0.75	0.9984	$0.75
Peak	$1.74	0.0922	$0.16
Cap	$0.27	0.6568	$0.18
Total cost		**$1.08**	

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 4.14. The calculations for 2019-20 are shown in Table 4.15 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.

TABLE 4.14 TOTAL PRUDENTIAL COSTS ($/MWH, NOMINAL) – 2020-21 FINAL DETERMINATION

Cost category	Energex NSLP	Ergon NSLP
AEMO pool	$0.46	$0.35
Hedge	$1.29	$1.08
Total	$1.75	$1.43

SOURCE: ACIL ALLEN ANALYSIS

TABLE 4.15 TOTAL PRUDENTIAL COSTS ($/MWH, NOMINAL) – 2019-20 FINAL DETERMINATION

Cost category	Energex NSLP	Ergon NSLP
AEMO pool	$0.40	$0.29
Hedge	$1.78	$1.22
Total	$2.18	$1.51

SOURCE: ACIL ALLEN ANALYSIS

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 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 Reports for Q4 2019 and Q1 2020 and ascribe RERT costs to the NEM regions of Victoria and New South Wales.

There are no costs ascribed to the Queensland region of the NEM for 2019-20 therefore estimated RERT costs for the Queensland region in the 2020-21 Final Determination are zero.

4.4.5 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement for the Energex NSLP and Ergon NSLP as set out in Table 4.16 and Table 4.17, respectively, for the 2020-21 Final Determination and is compared with the costs for 2019-20 Final Determination.

TABLE 4.16 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ENERGEX NSLP

Cost category	2019-20 Final Determination	2020-21 Final Determination
NEM management fees	$0.63	$0.71
Ancillary services	$0.37	$1.53
Hedge and pool prudential costs	$2.18	$1.75
Total	**$3.18**	**$3.99**

TABLE 4.17 TOTAL OF OTHER COSTS ($/MWH, NOMINAL) – ERGON NSLP

Cost category	2019-20 Final Determination	2020-21 Final Determination
NEM management fees	$0.63	$0.71
Ancillary services	$0.37	$1.53
Hedge and pool prudential costs	$1.51	$1.43
Total	**$2.51**	**$3.67**

4.5 Estimation of energy losses

The methodology up to this point produces price estimates at the Queensland regional reference node (RRN). Prices at the Queensland RRN must be adjusted for losses to the end-users. Distribution loss factors (DLF) for Energex and Ergon Energy east zone and average Marginal Loss Factors (MLF) for transmission losses from the reference node to major supply points in the distribution networks are applied.

The transmission loss factors from the Queensland reference node to the distribution network for Energex and Ergon Energy's east zone area are based on the average energy-weighted marginal loss factors (MLFs) for the Energex and Ergon Energy east zone Transmission Node Identities (TNIs). This analysis results in a transmission loss factor of 1.007 for Energex and 0.964 for the Ergon Energy east zone. These estimates are based on AEMO's final MLFs for 2020-21 weighted by the 2018-19 energy for the TNIs. 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 2020-21 is shown in Table 4.18.

TABLE 4.18 ESTIMATED TRANSMISSION AND DISTRIBUTION LOSS FACTORS FOR ENERGEX AND ERGON ENERGY'S EAST ZONE

Settlement classes	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Energex - NSLP - residential and small business and unmetered supply	1.052	1.007	1.060
Energex - Control tariff 9000	1.052	1.007	1.060
Energex - Control tariff 9100	1.052	1.007	1.060
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.031	0.964	0.993
Ergon Energy - NSLP - SAC demand and street lighting	1.093	0.964	1.053

SOURCE: ACIL ALLEN ANALYSIS BASED ON QUEENSLAND TNI ENERGY FOR 2018-19; AEMO'S FINAL MLFS FOR 2020-21 AND AEMO'S ENERGEX AND ERGON EAST ZONE FINAL DLFS FOR 2020-21.

As described by AEMO[16], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

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

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 2020-21 total energy costs (TEC) for the Final Determination for each of the settlement classes are presented in Table 4.19.

TABLE 4.19 ESTIMATED TEC FOR 2020-21 FINAL DETERMINATION

Settlement class	WEC at Qld reference node ($/MWh)	Renewable energy costs at Qld reference node ($/MWh)	Other costs Qld reference node ($/MWh)	Total transmission and distribution loss factor (MLF x DLF)	Network losses ($/MWh)	TEC at the customer terminal ($/MWh)	Change from 2019-20 Final Determination ($/MWh)	Change from 2019-20 Final Determination (%)
Energex - NSLP - residential and small business	$80.90	$14.30	$3.99	1.060	$5.95	$105.14	($10.92)	-9.41%
Energex - Controlled load tariff 9000 (31)	$63.49	$14.30	$3.99	1.060	$4.91	$86.69	($3.55)	-3.93%
Energex - Controlled load tariff 9100 (33)	$65.35	$14.30	$3.99	1.060	$5.02	$88.66	($10.03)	-10.16%
Energex - NSLP - unmetered supply	$80.90	$14.30	$3.99	1.060	$5.95	$105.14	($10.92)	-9.41%
Ergon Energy - NSLP - CAC and ICC	$72.41	$14.30	$3.99	0.993	($0.63)	$89.75	($3.75)	-4.01%
Ergon Energy - NSLP - SAC demand and street lighting	$72.41	$14.30	$3.99	1.053	$4.79	$95.17	($1.83)	-1.89%

SOURCE: ACIL ALLEN ANALYSIS

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

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.
- Hedge portfolio:
  - 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.
- Hedge or contract prices:
  - 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.

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