ACIL ALLEN

24 May 2023

Report to Queensland Competition Authority

# Estimated energy costs

## For use by the Queensland Competition Authority in its Final Determination of 2023-24 retail electricity tariffs

## About ACIL Allen

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

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

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

Suggested citation for this report

Estimated energy costs for 2023-24 retail electricity tariffs: Final Determination, ACIL Allen, May 2023

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# 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 2023-24 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 2023-24.

ACIL Allen is required to provide cost estimates for:

— the net system load profiles (NSLPs) and smart meter profiles in the Energex and Ergon distribution areas

— the load control profiles for small customers in the Energex distribution area

— the load control profiles for large business customers in the Ergon distribution area

— time-varying wholesale energy costs for small customers in the Energex distribution area

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

The report is presented as follows:

— Chapter 2 summarises our approach and methodology

— Chapter 3 provides updated spot price simulations.

— Chapter 4 responds to submissions on the QCA's *Draft determination: Regulated retail electricity prices for 2023–24* (March 2023) that refer to the methodology used to estimate energy costs in regulated retail electricity prices

— Chapter 5 summarises our derivation of the energy cost estimates.

# Overview of approach 2

## 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 2023 to 30 June 2024.

## 2.2 Components of the total energy cost estimates

ACIL Allen is required to estimate the Total Energy Costs (TEC) component of the retail tariffs. Total Energy Costs comprise the following components (as shown in Figure 2.1):

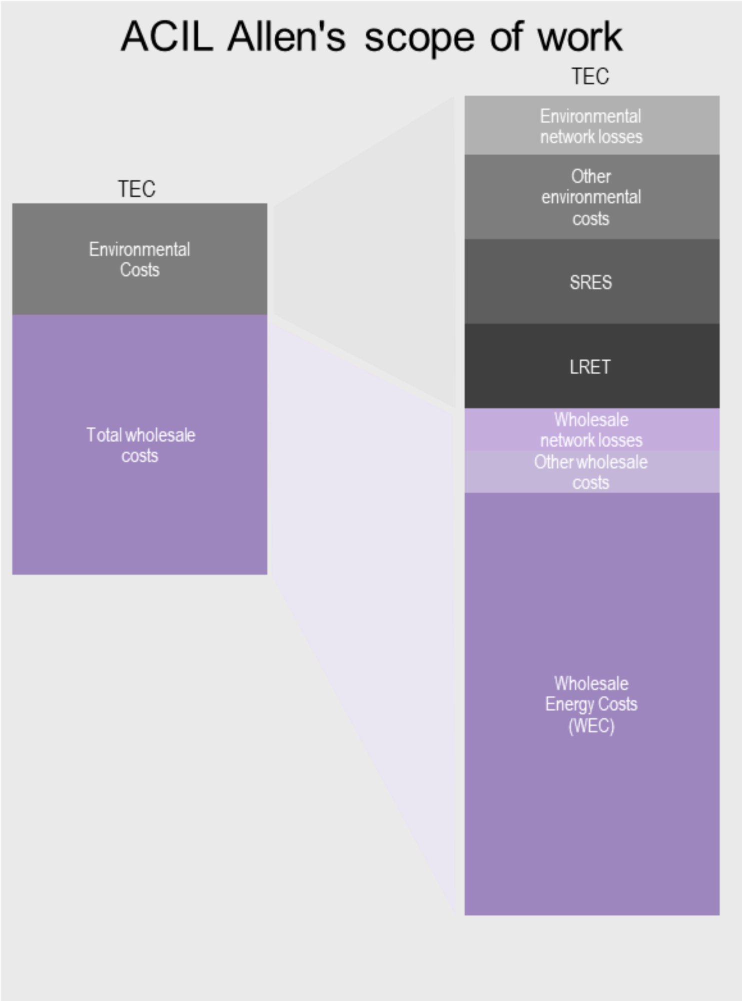
— Wholesale energy costs (WEC) for various demand profiles.

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

— Other wholesale costs: including National Electricity Market (NEM) fees, ancillary services charges, Reliability and Emergency Reserve Trader (RERT) costs, AEMO direction costs, and costs of meeting prudential requirements. In addition, this determination will also account for the known costs associated with the market interventions due to the triggering of administered pricing and spot market suspension that occurred in the NEM in June 2022.

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

**Figure 2.1** Components of TEC




*Source: ACIL Allen*

## 2.3 Methodology

ACIL Allen's methodology follows the methodology used to provide advice to the QCA for the 2013-14 to 2022-23 determinations.

The ACIL Allen methodology estimates costs from a retailing perspective. This involves estimating the energy and environmental costs that an electricity retailer would be expected to incur in a given determination year. The methodology includes undertaking wholesale energy market simulations to estimate expected spot market costs and volatility, and the hedging of the spot market price risk by entering electricity contracts with prices represented by the observable futures market data. Environmental and other energy costs are added to the wholesale energy costs and the total is then adjusted for network losses.

### 2.3.1 Estimating the WEC - market-based approach

Energy purchase costs are incurred by a retailer when purchasing energy from the NEM spot market to satisfy their retail load. However, given the volatile nature of wholesale electricity spot prices, which is an important and fundamental feature of an energy-only market (i.e., a market without a separate capacity mechanism), and that retailers charge their customers based on fixed rate tariffs (for a given period), a prudent retailer is incentivised to hedge its exposure to the spot market.

Hedging can be achieved by a number of means – a retailer can own or underwrite a portfolio of generators (the gen-tailer model), enter into bilateral contracts directly with generators, purchase over the counter (OTC) contracts via a broker, or take positions on the futures market. Typically, a retailer will employ a number of these hedging approaches. In addition, a retailer may choose to leave a portion of their load exposed to the spot market.

At the core of the market-based approach is an assumed contracting strategy that an efficient retailer would use to manage its electricity market risks. Such risks and the strategy used to mitigate them are an important part of electricity retailing. The contracting strategy adopted generally assumes that the retailer is partly exposed to the wholesale spot market and partly protected by the procured contracts.

The methodology simulates the cost of hedging by building up a portfolio of hedges consisting of base and peak swap contracts, and cap contracts (and this is discussed in more detail below).

Conceptually, in a given half-hourly settlement period, the retailer:

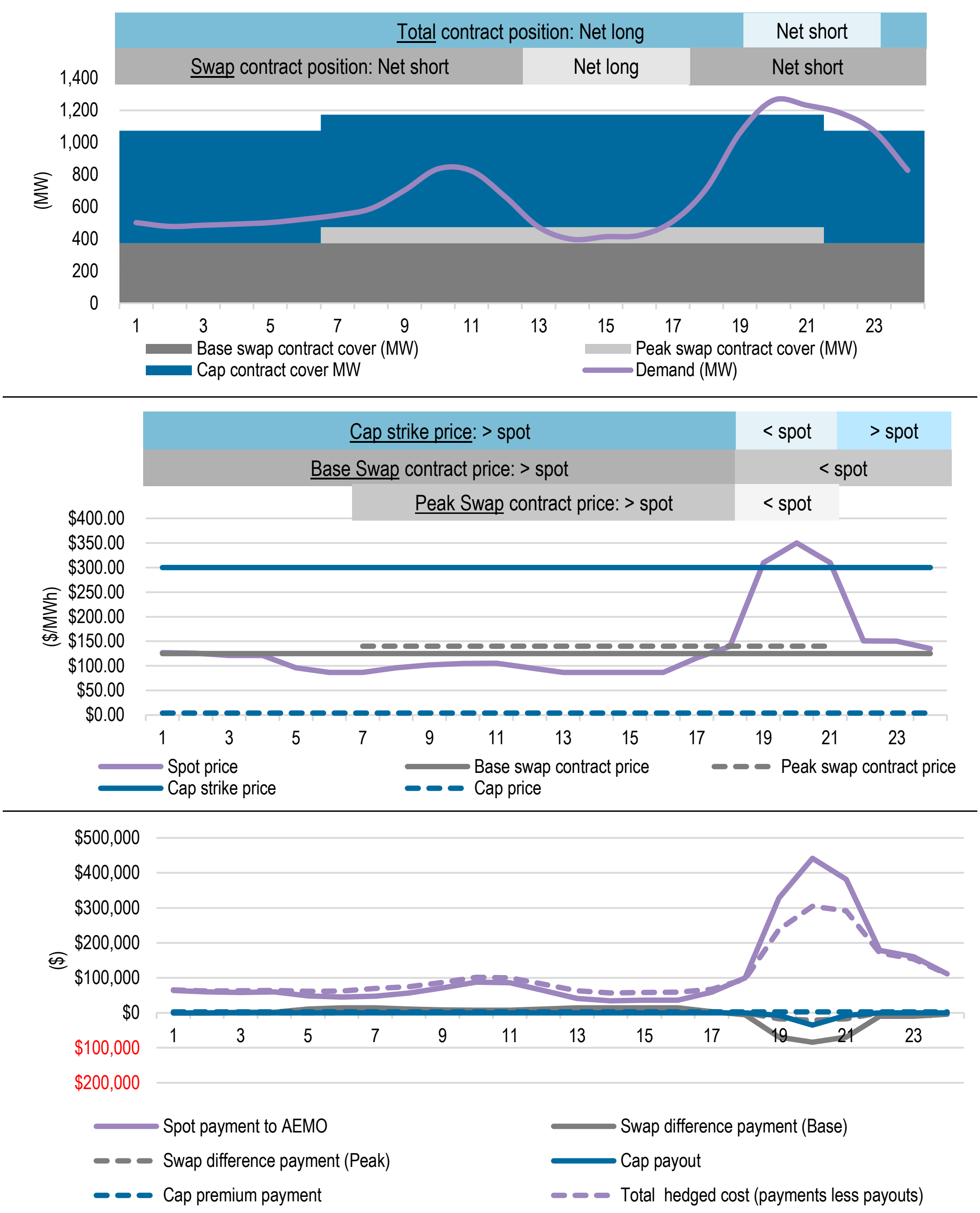
— Pays AEMO the spot price multiplied by the demand.
— Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract during the periods classified as peak. If the spot price is greater than the contract strike price than the counter party pays the retailer.
— Pays the contract counterparty the cap price multiplied by the cap contract quantity.
— If the spot price exceeds $300/MWh, receives from the contract counter party the difference between the spot price and $300, multiplied by the cap contract quantity.

Figure 2.2 shows an illustrative example of a hedging strategy for a given load across a 24-hour period.

In this example:

— The demand profile:
  – Varies between 400 MW and 1,300 MW.
  – Peaks between 6 pm and 10 pm, with a smaller morning peak between 9 am and 11 am.
— The hedging strategy:
  – Consists of 375 MW of base swaps, 100 MW of peak period swaps, and 700 MW of caps.
  – Means that demand exceeds the total of the contract cover between 7 pm and 10 pm by about 100 MW. Hence during these periods, the retailer is exposed to the spot price for 100 MW of the demand, and the remaining demand is covered by the hedges.
  – Demand is less than the hedging strategy for all other hours. Hence, during these periods the retailer in effect sells the excess hedge cover back to the market at the going spot price (and if the spot price is less than the contract price this represents a net cost to the retailer, and vice versa).

**Figure 2.2** Illustrative example of hedging strategy, prices and costs




*Source: ACIL Allen*

With this in mind, the WEC for a given demand profile for a given year is therefore generally a function of four components, the:

1. demand profile
2. wholesale electricity spot prices
3. forward contract prices
4. hedging strategy.

### Use of financial derivatives in estimating the WEC

As discussed above, retailers purchase electricity in the NEM at the spot price and use a number of strategies to manage their risk or exposure to the spot market. Market-based approaches adopted by regulators for estimating the WEC make use of financial derivative data given that it is readily available and transparent. This is not to say regulators are of the view that retailers only use financial derivatives to manage risk – it simply reflects the availability and transparency of data.

Some retailers also use vertical integration and Power Purchase Agreements (PPAs) to manage their risk. However, the associated costs, terms and conditions of these approaches are not readily available in the public domain. Further, smaller retailers may not be in a position to use vertical integration or PPAs and hence rely solely on financial derivatives.

Additionally, the value of long-dated assets associated with vertical integration and PPAs is determined by conditions in the market at a given point in time. The price in a PPA or the annualised historical cost of generation reflects the long term value of the generation anticipated at the time of commitment when the investor was faced with a variety of uncertain futures. As a consequence, there are considerable difficulties in using the price of PPAs or the annualised historical cost of generation as a basis for estimating current hedging costs.

In essence, the methodology uses available and transparent financial derivative data as a proxy for the range of other hedging instruments adopted by retailers.

### Use of load profiles in estimating the WEC

The following load profiles are required for the given determination year:

— system load for each region of the NEM (that is, the load to be satisfied by scheduled and semi-scheduled generation) – used to model the regional wholesale electricity spot prices
— Net System Load Profiles (NSLPs) for the Energex and Ergon distribution networks
— interval meter load data for residential and small business customers in the Energex distribution network
— interval meter load data for large business customers in the Ergon distribution network
— controlled load profiles (CLPs) for small customers in the Energex distribution network
— CLPs for small business customers on a primary load control tariff in the Energex distribution network
— CLPs for large business customers in the Ergon distribution network.

Historical load data is available from AEMO – as shown in Table 2.1. The exception is the load data for the small business primary CLP in the Energex distribution network, which is derived from 2019-20 Ergon Energy Agricultural Tariff Trial data set[1].

**Table 2.1** Sources of load data

| Distribution Network | Load Type | Load | Source |
|---|---|---|---|
| NA | System Load | QLD1 | MMS |
| Energex | NSLP | NSLP, ENERGEX | MSATS |
| Energex | Residential and small business customers on interval meters | Energex Residential < 100 MWh and Business < 100 MWh | QCA data request to AEMO |

[1] Details of this data set and our treatment of it can be found in our report to the QCA as part of the 2020-21 Supplementary Pricing Review (https://www.qca.org.au/wp-content/uploads/2020/10/rle_j0426-acil-allen-report-for-final-determination-28-sep-2020.pdf).

| Distribution Network | Load Type | Load | Source |
|---|---|---|---|
| Ergon | NSLP | NSLP, ERGON | MSATS |
| Ergon | Large business customers on interval meters | Ergon Business >= 100 MWh | QCA data request to AEMO |
| Energex | CLP – small customers | QLDEGXCL31, ENERGEX | MSATS |
| Energex | CLP – small customers | QLDEGXCL33, ENERGEX | MSATS |
| Energex | CLP – small business primary load control tariff | 2019-20 Ergon Energy Agricultural Tariff Trial | Energy Queensland |
| Ergon | CLP – large business primary and secondary load control tariffs | QLDEGXCL33, ENERGEX | MSATS |

*Source: AEMO*

***Use of interval meter data for residential and small business customers***

Since the Power of Choice reforms in 2017, new rooftop solar PV installations require the replacement of an existing accumulation meter with a new smart meter[2]. In previous determinations, the NSLP was used as the representative load profile for residential and small business customers because the majority (about 90 per cent in 2020, and 80 per cent in 2021) of residential and small business customers in Queensland were on accumulation (or basic) meters. And those customers with interval (or smart) meters were in the minority. However, ACIL Allen estimates the penetration of interval meters in Queensland in 2022 increased to about 30 per cent.

With the likely continued roll out of interval meters due to retailers responding to various market incentives, the end-of-life replacement of older accumulation meters and the AEMC's recommended target of 100 per cent uptake of smart meters by 2030, it is likely customers on interval meters will be the majority in the next few years.

In this determination we have used a combination of the NSLP and interval meter data in our estimation of the WEC. The use of interval meter data improves the estimation of the cost of supplying energy to small customers because the interval meter data in addition to the NSLP better reflects the shape of small customers load.

There are some considerations in making this decision:

— Data transparency: At this stage AEMO does not make interval meter load profile data publicly available on its website. This means, until AEMO publish this data, that the QCA will need to proactively request the data in time for each determination, and that the data cannot be readily accessed by stakeholders for verification.

— Data validity: The purpose of the determination is to estimate the WEC from a retailer's perspective. AEMO constructs the NSLP including rooftop PV exported to the grid. Inclusion of exports in the NSLP is not counter to the purpose of the determination given that retailers are charged by AEMO based on the NSLP. However, for customers on interval meters, presumably it would be the energy drawn from the grid that ought to be included in the WEC estimation process, that is, rooftop solar PV exports ought to be removed from the data as these are treated separately by retailers. ACIL Allen understands that prior to the introduction of five-minute

[2] In this report, smart meter is used interchangeably with interval meter for the purposes of estimating load profiles. That is, interval/smart meters record how much electricity is used in each NEM settlement period, versus accumulation meters which track total electricity usage at any point in time.

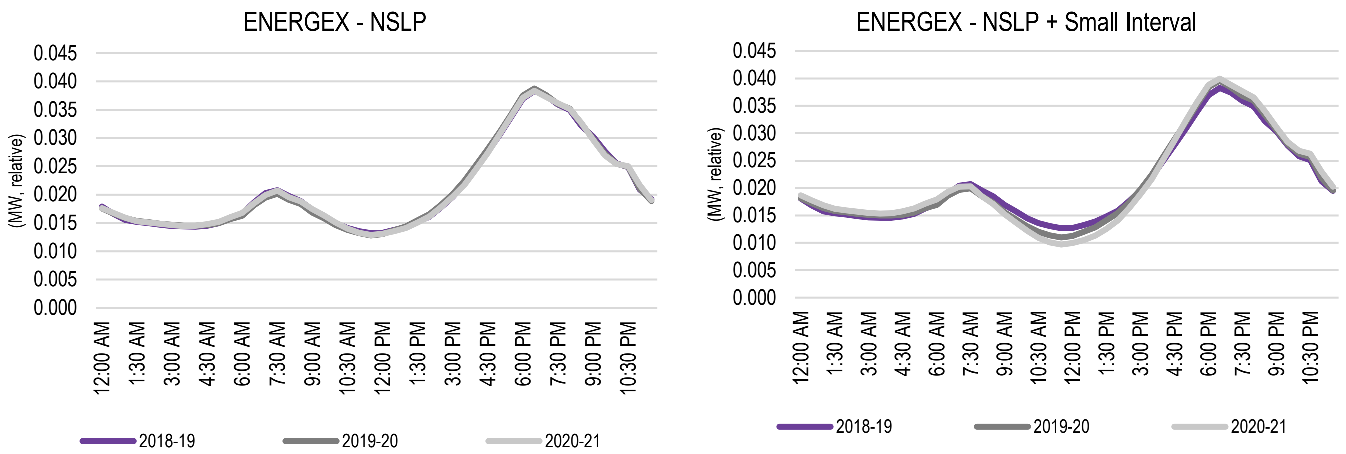
settlement (5MS) in October 2021, interval meter load data is available on an aggregate basis – that is, it includes exports from rooftop PV which cannot be readily separated from the load. Post 5MS, the data is separated into load drawn from the grid and solar exports injected to the grid.

— Step change in WEC estimates: If the aggregate load profile of customers on interval meters is different to that of customers on the NSLP, then delaying the aggregation of the interval meter load data into the WEC estimation process runs the risk of a step change in WEC from one year to the next (all other things equal), whereas including the interval meter load data sooner when it represents a smaller proportion of customers will result in a modest change.

ACIL Allen is of the view that it is better to commence using the interval meter data in combination with the NSLP data sooner rather than later as it removes the risk of a step change in WEC estimate. Although the interval meter data includes rooftop PV exports, this will gradually be unwound over the next few determinations as the methodology uses more recent post-5MS data. and in any case the interval meter data at this stage represents the load profiles of about 30 per cent of residential and small business customers.

Figure 2.3 shows that aggregating the NSLP and interval meter data does not change substantially the shape of the load profile when compared with the NSLP. However, the aggregate profiles show a continuation of the carve out of demand during daylight hours over the past few years (unlike the NSLP). This is likely due to a new rooftop PV installation at each given site being coupled with the replacement of the accumulation meter with an interval meter.

**Figure 2.3** Average time of day demand (MW, relative)




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*

### Customer groups and load profiles used

Table 2.2 summarises which load profiles are adopted for the estimation of the WEC for each customer settlement class (or customer group).

**Table 2.2** Load profiles adopted for estimation of WEC by customer settlement class

| Customer settlement class | Load profile used in WEC estimation |
|---|---|
| Energex - Residential and small business | Energex NSLP + Residential and small business interval meter load |
| Energex - Controlled load tariff 9000 (31) | QLDEGXCL31 |
| Energex - Controlled load tariff 9100 (33) | QLDEGXCL33 |
| Energex - Unmetered supply | Energex NSLP + Residential and small business interval meter load |
| Ergon Energy - CAC and ICC | Ergon large business interval meter load |
| Ergon Energy - SAC demand and street lighting | Ergon NSLP + Large business interval meter load |
| Energex – Small business primary load control tariff | 2019-20 Ergon Energy Agricultural Tariff Trial load |
| Ergon – Large business primary and secondary load control tariffs | QLDEGXCL33 |

*Source: ACIL Allen*

### Key steps to estimating the WEC

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

1. Forecast the hourly load profile – generally as a function of the underlying demand forecast as published by the Australian Energy Market Operator (AEMO), and accounting for further uptake of rooftop solar PV. A stochastic demand and renewable energy resource model to develop 51 weather influenced annual simulations of hourly demand and renewable energy resource traces which are developed so as to maintain the appropriate correlation between the various regional and NSLP/CLP/interval meter demands, and various renewable energy zone resources.
2. Use a stochastic availability model to develop 11 annual simulations of hourly thermal power station availability.
3. Forecast hourly wholesale electricity spot prices by using ACIL Allen's proprietary wholesale energy market model, *PowerMark*. *PowerMark* produces 561 (i.e. 51 by 11) simulations of hourly spot prices of the NEM using the stochastic demand and renewable energy resource traces and power station availabilities as inputs.
4. Estimate the forward contract price using ASX Energy contract price data, verified with broker data. The book build is based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price.
5. Adopt an assumed hedging strategy – the hedging strategy represents a strategy that a retailer would undertake to hedge against risk in the spot price in a given year. It is generally assumed that a retailer's risk management strategy would result in contracts being entered into progressively over a two- or three-year period, resulting in a mix (or portfolio) of base (or flat), peak and cap contracts.
6. Calculate the spot and contracting cost for each hour and aggregate for each of the 561 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

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

The distribution of outcomes produced by the above approach is then analysed to provide a risk assessed estimate of the WEC. ACIL Allen adopts the 95th percentile WEC from the distribution of WECs as the final estimate. In practice, the distribution of WECs from the simulations exhibits a relatively narrow spread when compared to estimates based on the load being 100 per cent exposed to the spot market, which is to be expected since they are hedged values. Choosing the 95th percentile reduces the risk of understating the true WEC, since only five per cent of WEC estimates exceed this value.

**Choosing the appropriate hedging strategy**

As mentioned above, multiple hedging strategies are tested by varying the mix of base/peak/cap contracts for each quarter. This is done by running the hedge model for a large number[3] of simulations for each strategy and analysing the resulting distribution of WECs for each given strategy – and in particular, keeping note of the 95th percentile WEC for each strategy. We select a strategy that is robust and plausible for each load profile, and minimises the 95th percentile WEC, noting that:

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

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

**Demand-side settings**

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

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

The key steps in developing the demand profiles are:

— The half-hourly demand profiles of the past three years are obtained. The profiles are adjusted by ‘adding’ back the estimated rooftop PV generation for the system demand and each NSLP and interval meter load profile (based on the amount of rooftop PV in each distribution network).
— A stochastic demand model is used to develop about 51 weather influenced simulations of hourly demand traces for the NSLPs and interval meter loads, each regional demand, and each renewable resource – importantly maintaining the correlation between each of these variables.

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

The approach takes the past three years of actual demand data, as well as the past 51 years of weather data and uses a matching algorithm to produce 51 sets of weather-related demand profiles of 17,520 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead, it accepts there is a relationship and uses a matching algorithm to find the closest matching weather outcomes for a given day across the entire NEM from the past three years to represent a given day in the past.

— The set of 51 simulations of regional system demands is then grown to the AEMO demand forecast using a non-linear transformation so that the average annual energy across the 51 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 51 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 seasonal peaks from the AEMO demand forecast.

— A relationship between the variation in the NSLPs and interval meter load profiles, and the corresponding regional demand from the past four years is developed to measure the change in NSLP and interval meter load as a function of the change in regional demand. This relationship is then applied to produce 51 simulations of weather related NSLP and interval meter load profiles of 17,520 half-hourly loads which are appropriately correlated with system demand, but also exhibit an appropriate level of variation in the NSLP and interval meter load across the 51 simulations.

— The projected uptake of rooftop PV for the determination year is obtained (using our internal rooftop PV uptake model).

— The half-hourly rooftop PV output profile is then grown to the forecast uptake and deducted from the system demand, NSLPs and interval meter loads.

***Date range of actual demand data used in the analysis***

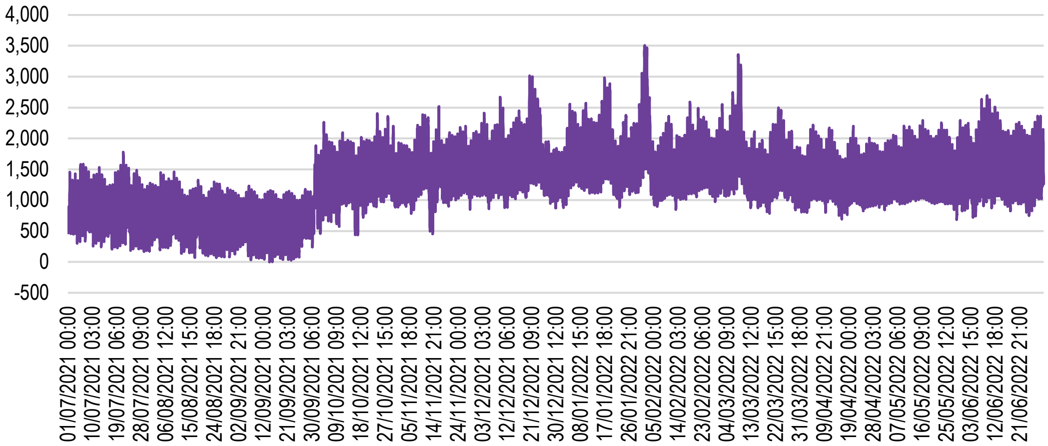
As noted above, the methodology usually uses the most recent past three years of actual demand data. For the 2023-24 determination this would mean using load data from the 2019-20 to 2021-22 financial years. With the introduction of 5MS in October 2021, ACIL Allen noted a long delay in the release of the NSLP data by AEMO, with the data released only in December 2022. Upon analysis of the data, we noted the step change in the Energex NSLP load coinciding with 5MS (as shown in Figure 2.4). We also noted a step change in the NSLP of South Australia with 5MS. A change could not be detected for the Ergon NSLP (or the New South Wales NSLPs).

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

Certainly, Figure 2.5 shows the average time of day shape of the NSLP has changed with the commencement of 5MS, which is not easily explainable.

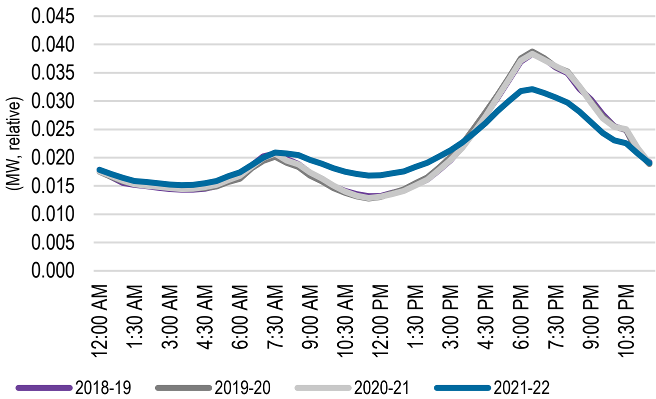
It seems unusual that the NSLP should experience such a change that is not readily explainable (or at least by an explanation accessible to those outside of AEMO). For this reason, we have used the 2018-19 to 2020-21 demand data set as the starting input for the 2023-24 determination (this is the same demand data set used for the 2022-23 determination), rather than use the 2021-22 data. Although it is not ideal to use the older data set, we are of the view that doing so introduces far less error than adopting the newer data. Regardless of the underlying demand data set used, it should be recalled that the methodology scales the data set to the demand forecast parameters of 2023-24 and adjusts it for the forecast of rooftop PV for 2023-24 (rather than simply using the same scaled demand data set from the 2022-23 determination).

**Figure 2.4** Energex NSLP (MW) – 2021-22




*Source: ACIL Allen analysis of AEMO data*

**Figure 2.5** Average time of day demand (MW, relative) – Energex NSLP




*Source: ACIL Allen analysis of AEMO data*

### Supply side settings

ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2023-24 we use our December 2022 Reference case projection settings which, in the short term, are closely aligned with AEMO's Integrated System Plan (ISP) and ESOO. Table 2.3 summarises the key assumptions adopted in the Reference case for the spot price modelling pertinent for the 2023-24 period.

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

**Table 2.3** Overview of key modelling assumptions relevant for 2023-24

| Assumption | Details | | | |
|---|---|---|---|---|
| **Macro-economic variables** | — Exchange rate of AUD to USD 0.7 AUD/USD for 2023-24.<br>— The brent crude oil price is assumed to converge from current levels to USD65/barrel by the mid-2020s and remain at this level in the long-term.<br>— International thermal coal prices are assumed to converge from current levels of about USD$150/t to USD$120/t by 2024. | | | |
| **Electricity demand** | **Underlying demand**<br>– Equivalent to AEMO 2022 ESOO Central scenario (energy and peak demand)<br>— **Aluminium smelters** are assumed to remain operational.<br>— To reflect a higher rate of NEM-wide **electrification** the Reference case includes annual electrification demand from AEMO's 2022 ISP Strong Electrification scenario | **Rooftop PV**<br>ACIL Allen's in-house model of Rooftop PV uptake:<br>— NEM-wide Rooftop PV uptake is about 20 per cent higher than AEMO's Central forecast by 2030. | **Behind-the-meter BESS**<br>ACIL Allen's in-house model of behind-the-meter BESS uptake (linked to rooftop PV model):<br>— Higher NEM-wide uptake relative to AEMO Central forecast, about 38 per cent higher by 2050. | **Electric vehicles**<br>— AEMO's 2022 ISP Strong Electrification scenario<br>— ACIL Allen's charging profiles: a blend of three charging behaviours which changes over time as charging infrastructure is developed. Includes an overnight charging profile, a daytime charging profile and a late evening/convenience charging profile. |

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

<table>
<tr><td></td><td>ahead (i.e., project has reached financial close)</td><td colspan="2"></td></tr>
<tr><td>Gas prices into gas-fired power stations</td><td colspan="3">For 2023-24, it is assumed that gas prices are capped at $12/GJ as part of the Government’s response to high electricity prices. However, the modelling assumes the price cap applies to CCGT plant and not peaking plant. Peaking plant are assumed to purchase their marginal gas on a short term basis at a price of $25/GJ (plus transport costs) and hence are exempt from the price cap. Further discussion on the treatment of gas and coal price caps in the spot price simulations is provided in Chapter 3.</td></tr>
<tr><td>Coal prices into coal-fired power stations</td><td colspan="3">ACIL Allen’s in-house understanding of the cost of thermal coal to the NEM’s coal-fired power stations, based on existing contracts with domestic mines and the plant’s exposure to the international export market. For 2023-24, domestic coal prices are capped at AUD$125/tonne as part of the Government’s response to high electricity prices. Further discussion on the treatment of gas and coal price caps in the spot price simulations is provided in Chapter 3.</td></tr>
<tr><td>Interconnectors</td><td>Existing interconnection<br>Assumed transfer capabilities updated to reflect recent history and known constraints (e.g., related to planned outages as part of upgrade works).</td><td>ISP committed and actionable projects included:<br>— QNI minor (July 2023)<br>— VNI Minor (Sep 2022)</td><td>Victoria’s System Integrity Protection Scheme<br>The Big Battery is included as a 300 MW/450 MWh battery since 1 October 2021 (increases the VNI import limit by 250 MW in summer at peak times).</td></tr>
<tr><td>Marginal loss factors</td><td colspan="3">ACIL Allen’s projections of average annual marginal loss factors (MLF) by generator DUID, developed using commercial power flow software.</td></tr>
<tr><td>Constraints</td><td colspan="3">— Thermal constraints which impact renewable energy zones and result in generator curtailment greater are included in the Reference case modelling. Stability limit constraints which have a material impact on interstate flows and regional prices during peak periods are also included.</td></tr>
<tr><td>Generator availability</td><td colspan="3">PowerMark includes a planned maintenance schedule and a set of random unplanned outages for each generator:<br>— The latest MTPASA available at the time the Reference case is developed is adopted for planned maintenance.<br>— For coal plant, an availability of broadly 75-85 per cent based on analysis of coal generator performance. This varies for each generator depending on age of the plant and recently observed outcomes.<br>— Black coal plants are generally assumed to have planned maintenance schedules that equate to about one month every two years.<br>— The brown coal plant tend to have a schedule that equates to one month every four years and the older brown coal plant a schedule that equates to one month every year.</td></tr>
</table>

| | |
|---|---|
| | — For mid merit gas plant, about 95 per cent based on annual maintenance requirements and assumed forced outage rates.<br>— For peaking plant, a 1.5 per cent forced outage rate. Although peaking plant undergo planned maintenance, we assume that this maintenance is scheduled during the off-peak months when the plant are rarely used.<br>— For hydro plant, an overall availability of 95 per cent per year. |

*Source: ACIL Allen*

### 2.3.2 New committed supply

Table 5.2 shows the near-term entrants that ACIL Allen considers committed projects and are therefore included in the Reference case. These projects are not yet registered in the market but are expected to come online in the near-term future.

**Table 2.4** Near-term addition to supply

| ID | Region | Name | Generation Technology | Capacity (MW) | First energy exports |
|---|---|---|---|---|---|
| 1 | NSW1 | Avonlie Solar Farm | Solar | 190 | Q3 2023 |
| 2 | NSW1 | Bango Wind Farm (extension) | Wind | 85 | Q3 2023 |
| 3 | NSW1 | Capital Battery | Battery | 100 | Q2 2023 |
| 4 | NSW1 | Crookwell 3 WF | Wind | 58 | Q1 2023 |
| 5 | NSW1 | Hunter Power Project | Natural gas | 660 | Q4 2023 |
| 6 | NSW1 | Riverina Energy Storage System Discharge | Battery | 100 | Q1 2023 |
| 7 | NSW1 | Rye Park WF | Wind | 396 | Q1 2024 |
| 8 | NSW1 | Tallawara B Power Station | Natural gas | 316 | Q4 2023 |
| 9 | NSW1 | West Wyalong Solar Farm | Solar | 90 | Q1 2023 |
| 10 | NSW1 | Flyers Creek | Wind | 145 | Q1 2024 |
| 11 | QLD1 | Bouldercombe Battery | Battery | 50 | Q2 2023 |
| 12 | QLD1 | Clarke Creek WF | Wind | 450 | Q3 2023 |
| 13 | QLD1 | Dulacca WF | Wind | 180 | Q1 2023 |
| 14 | QLD1 | Edenvale Solar Park | Solar | 146 | Q1 2023 |
| 15 | QLD1 | Kaban WF | Wind | 157 | Q1 2023 |
| 16 | QLD1 | Kidston Storage Hydro | Pumped Hydro | 250 | Q3 2024 |
| 17 | QLD1 | Macintyre Wind Farm | Wind | 923 | Q1 2023 |
| 18 | QLD1 | Wambo Wind Farm | Wind | 250 | Q1 2024 |
| 19 | QLD1 | Karara Wind Farm | Wind | 103 | Q1 2024 |
| 20 | SA1 | Cultana Solar Farm | Solar | 280 | Q2 2023 |
| 21 | SA1 | Goyder South WF | Wind | 100 | Q3 2024 |
| 22 | SA1 | Torrens Island BESS | Battery | 250 | Q1 2023 |
| 23 | NSW1 | Riverina Solar Farm | Solar | 40 | Q2 2023 |
| 24 | NSW1 | Wollar Solar Farm | Solar | 280 | Q4 2023 |
| 25 | NSW1 | Wellington North Solar Farm | Solar | 300 | Q3 2024 |
| 26 | SA1 | Tailem Bend Stage 2 Solar Project | Solar | 87 | Q3 2023 |
| 27 | SA1 | Goyder South WF | Wind | 412 | Q3 2024 |
| 28 | QLD1 | Wandoan South Solar Stage 1 | Solar | 125 | Q2 2023 |
| 29 | VIC1 | Wunghnu Solar Farm | Solar | 80 | Q3 2024 |
| 30 | NSW1 | Waratah Super Battery | Battery | 850 | Q3 2025 |
| 31 | NSW1 | Stubbo Solar Farm | Solar | 400 | Q1 2024 |
| 32 | QLD1 | Tarong West Wind Farm | Wind | 500 | Q1 2026 |

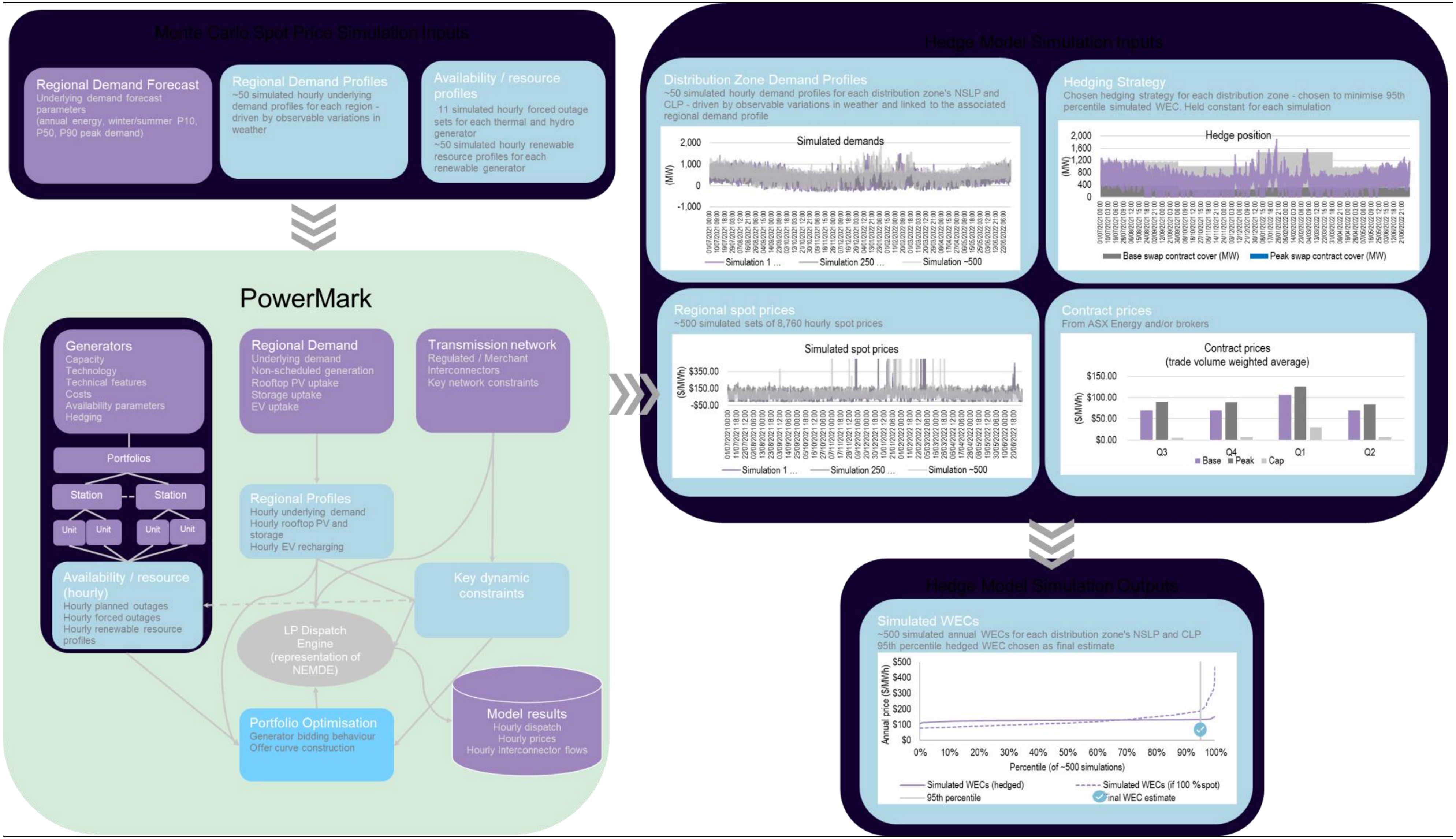
| ID | Region | Name | Generation Technology | Capacity (MW) | First energy exports |
|---|---|---|---|---|---|
| 33 | SA1 | Tailem Bend Battery Project | Battery | 51 | Q3 2023 |
| 34 | NSW1 | Broken Hill Battery | Battery | 50 | Q3 2023 |
| 35 | NSW1 | Darlington Point Energy Storage System | Battery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

*Source: ACIL Allen*

**Summary infographic of the approach to estimate the WEC**

Figure 2.6 provides an infographic type summary of the data, inputs, and flow of the market-based approach to estimating the WEC.

**Figure 2.6** Estimating the WEC – market-based approach



### Time varying WECs

The requirement to estimate time varying WECs for Energex small customers means the load profile is to be time sliced into period types. The WECs are to be based on the overall WEC for Energex small customers.

The QCA has provided ACIL Allen with the following specifications of the time slices for the period types:

— Daylight: 9am – 4pm
— Evening Peak: 4pm – 9pm
— Night: 9pm – 9am.

The WEC for a given period type, p, is calculated as follows: WECp = DWPp * WECt / DWPt.

That is, the WECp equals the ratio WECt for the total (t) demand profile to the DWPt for the total demand profile, multiplied by the spot DWPp of the period type, p.

In effect, the method assumes the ratio of the WEC to DWP is the same for all period types. This method preserves the total WEC - that is, the sum product of the derived period type WECs and their energy, divided by the total energy of the profile equals the total demand profile WEC. And it is likely to provide the behavioural signals sought by this type of tariff – since the DWP during daylight hours will be less than the DWP for other period types.

### WEC estimation accuracy

The estimated WEC for any determination will invariably be different to the actual WEC incurred. This will be a function of several factors, including the actual hedging strategy adopted by a retailer (noting different retailers may have different strategies) compared with the simplified hedging strategy adopted in the methodology, the actual load profiles, spot price and contract price outcomes.

Although we attempt to minimise the error of the estimate by undertaking a large number of simulations to account for variations in weather related demand, thermal plant availability, renewable energy resource, and spot price outcomes, the methodology does not attempt to predict the final trade weighted average contract price for each of the assumed contract products adopted in the hedging strategy. Instead, the methodology relies on contract data available at the time the Determination is made.

Contract prices are a key driver of the WEC estimate. In some years, contract prices may increase after the Final Determination is made, in other years they may decrease, and in some cases, they may remain relatively stable. Figure 2.7 provides examples of this phenomenon for quarter one base contracts in Queensland over the past four years. The graphs show the daily contract prices, the moving trade weighted average price, as well as the trade weighted average price at the time of the respective Final Determination.

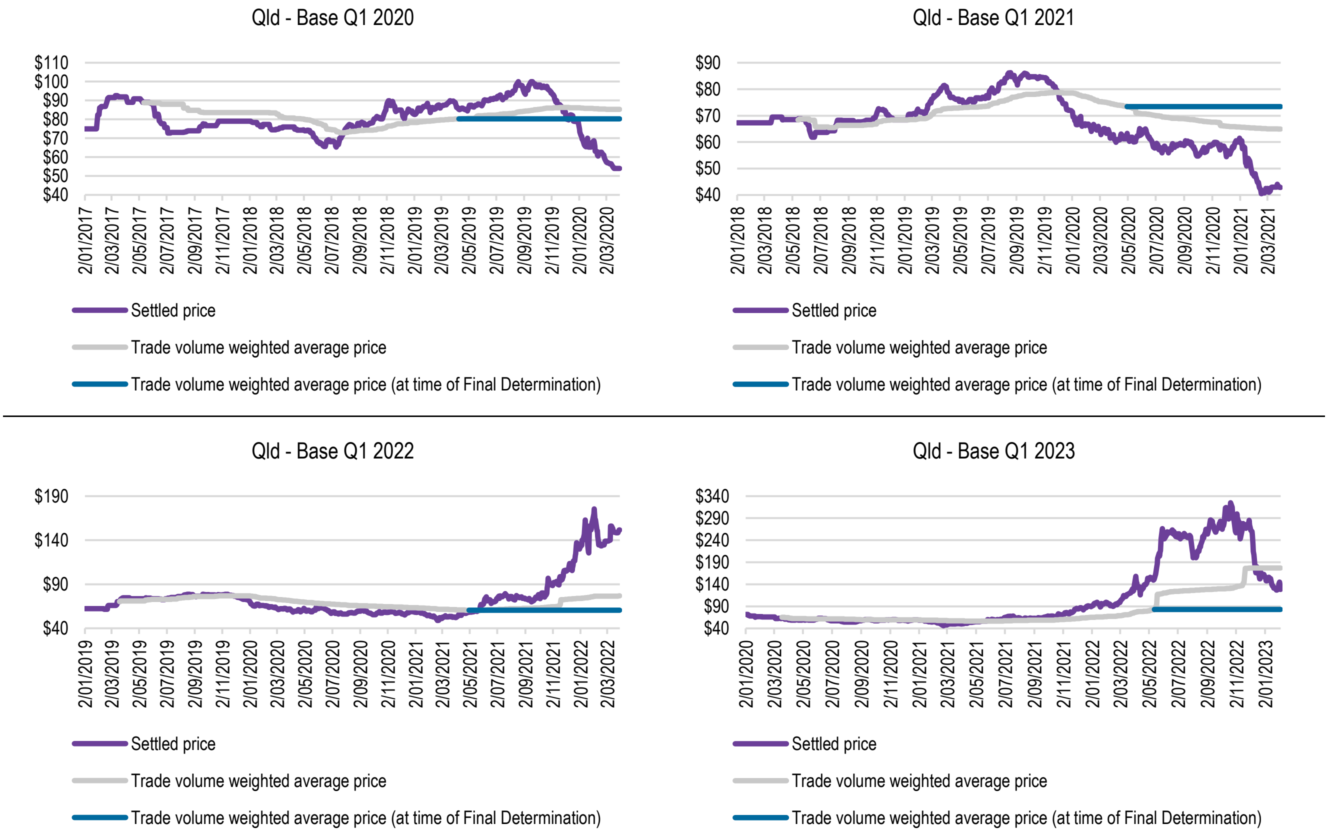
After the date the 2019-20 Final Determination was made, Q1 2020 traded prices increased slightly and then decreased slightly resulting in an actual trade weighted average price very similar to that used in the Final Determination. This is an example of a stable market price environment (at least in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

After the date the 2020-21 Final Determination was made, Q1 2021 traded prices decreased consistently resulting in an actual trade weighted average price about $8.50 lower than that used in the Final Determination. This is an example of a decreasing market price environment – resulting in an overestimate of the WEC (all other things equal).

After the date the 2021-22 Final Determination was made, Q1 2022 traded prices increased consistently resulting in an actual trade weighted average price about $17.00 higher than that used in the Final Determination. This is an example of an increasing market price environment – resulting in an underestimate of the WEC (all other things equal).

After the date the 2022-23 Final Determination was made, Q1 2023 traded prices increased substantially resulting in an actual trade weighted average price about $90.00 higher than that used in the Final Determination. This is another, and more extreme, example of an increasing market price environment – resulting in a substantial underestimate of the WEC (all other things equal).

**Figure 2.7** Daily settlement prices and trade volume weighted prices ($/MWh) for Q1 base contracts in Queensland




*Source: ACIL Allen analysis of ASX Energy data*

The graphs in Figure 2.7 demonstrate a number of important points about the WEC estimation methodology:

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

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

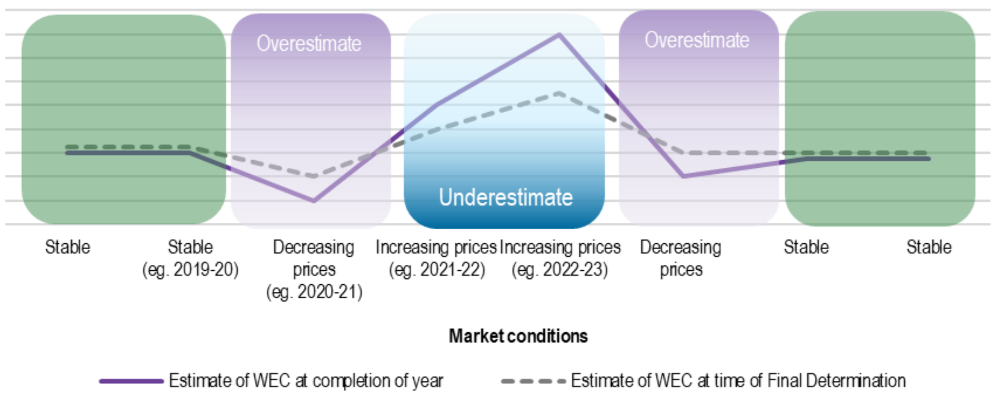
— The error in the WEC estimate, due to contract price variation, is likely to be greater in an environment of increasing prices, than it is in an environment of decreasing prices. This is because of the skewed nature of wholesale electricity prices in the NEM – prices can increase a lot more than they can decrease – and demonstrates the risk faced by retailers. This is another reason to adopt a higher percentile of the simulated WECs.

— Adopting a bookbuild period from the date of the first trade, rather than artificially constraining it to a shorter time frame, means that the trade weighted average contract price has a greater chance of smoothing out temporary fluctuations in contract prices.

In some years contract prices will increase, and in others they will decrease after the Final Determination is made. It is unlikely that the market will enter into an extended period of seemingly ever-increasing or -decreasing prices – at some point, the market will respond accordingly with investment and/or retirement of capacity.

Hence, it is likely that over the long run, the market will follow some form of pattern of increasing, decreasing and stable price outcomes. With this in mind, the methodology may well result in a comparatively smooth WEC estimate trajectory – underestimating outcomes in an increasing price environment, and overestimating outcomes in a decreasing price environment – as illustrated in Figure 2.8.

**Figure 2.8** Illustrative comparison of WEC estimation accuracy given market environment




*Source: ACIL Allen*

A conclusion that might be drawn from the above analysis, particularly for the 2022-23 Determination, is that the methodology is not fit for purpose. We acknowledge that the difference between the weighted average contact price at the time of the 2022-23 Final Determination and the likely final price is large. This is the outcome of developing a Determination on an annual basis in a rapidly changing market environment, rather than the methodology itself. The 2022-23 Final Determination was based on Q1 2023 contract data up to about 10 or so months prior to the completion of the Q1 2023 quarter. As has been observed, a lot can change in 10 or so months.

Regular updates to the estimation of the WEC during periods of rapid change in the market environment improve the accuracy of the WEC estimate. Under current legislative arrangements, the QCA is required to publish their Final Determination on regulated retail electricity prices prior to the commencement of the regulated period (1 July). The publication of a draft and final determination allows for as many updates to contract price data as possible within this timeframe. Under the current determination period, the date of the Final Determination has been extended to early June 2023.

### 2.3.3 Other wholesale costs

#### Market fees and ancillary services costs

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

#### *NEM fees*

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

The approach for estimating market fees is to make use of AEMO's latest budget report. AEMO's 2023-24 draft budget report was released in April 2023 and adopted for the Final determination.

Consistent with all previous determinations, fees published in AEMO's budget that are expressed as a cost per connection per week, are converted to $/MWh terms by multiplying the cost by the number of connections and weeks per year, and then dividing by the customer load forecast (all of which are provided in the AEMO budget report).

#### *Ancillary services charges*

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security, and reliability. AEMO recovers the costs of these services from market participants. These fees are published by AEMO on its website on a weekly basis.

The approach used for estimating ancillary services costs is to average the most recent 52 weeks of costs to recover ancillary services from customers, which is published on the AEMO website. This is done on a region-by-region basis.

### Prudential costs

Prudential costs, for AEMO, as well as representing the capital used to meet prudential requirements to support hedging take into account:

— the AEMO assessed maximum credit limit (MCL)
— the future risk-weighted spot price
— participant specific risk adjustment factors
— AEMO published volatility factors
— futures market prudential obligation factors, including:
— the price scanning range (PSR)
— the intra month spread charge
— the spot isolation rate.

Prudential costs are calculated for each distribution network. The prudential costs are then used as a proxy for prudential costs for the various load profiles within each network.

AEMO publishes volatility factors two years in advance. Similarly, ASX Energy publishes initial margin parameters two years in advance.

#### *AEMO prudential costs*

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

— bank guarantees
— reallocation certificates
— prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = OSL + PML

Where for the Summer (December to March), Winter (May to August) and Shoulder (other months):

OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x (GST + 1) x 35 days

PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x (GST + 1) x 7 days

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5 percent annual charge for 42 days or 2.5%*(42/365) = 0.288 percent.

***Hedge prudential costs***

ACIL Allen relies on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The money market rate used in this analysis is 3.85 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

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

— the price scanning range (PSR) expressed as a percentage of the contract face value and is set for each of the base, peak and cap contract types
— the intra monthly spread charge and is set for each of the base, peak and cap contract types
— the spot isolation rate and is set for each of the base, peak and cap contract types.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter. This is divided by the average hours in the given quarter. Then applying an assumed funding cost but adjusted for an assumed return on cash lodged with the clearing results in the prudential cost per MWh for each contract type.

**Reliability and Emergency Reserve Trader (RERT)**

Given the RERT is called upon under extreme circumstances only, ACIL Allen is of the opinion that it is difficult to project into the future. Although it may be possible to make use of previous costs of the RERT and relate these to AEMO's projection of USE in the ESOO, there is little data available at this point to take this approach.

Therefore, as with the ancillary services, we use the RERT costs as published by AEMO for the 12-month period prior to the Determination. ACIL Allen expresses the cost based on energy consumption, by taking the reported cost in dollar terms from AEMO for the given region and prorating the cost across all consumers in the region on a consumption basis.

**Retailer Reliability Obligation**

The Retailer Reliability Obligation (RRO) started on 1 July 2019 to help manage the risk of declining reliability of supply in response to the recent large amounts of investment in intermittent renewable projects coupled with recent and potential closures of thermal power stations.

If the RRO is triggered for a given quarter and region of the NEM, then retailers need to secure sufficient *qualifying contracts* to cover their share of a one-in-two-year peak demand.

The RRO is currently not triggered for 2023-24 in Queensland, and hence we are not required to account for the RRO in the wholesale costs for 2023-24. However, it is worth noting that this cost component should be included as part of the wholesale cost if the RRO is triggered in future determinations.

We think that entering into a mix of firm base, peak, and cap contracts satisfies the qualifying contract definition. As part of the current WEC estimation methodology, an algorithm is run to determine the optimal hedge cover for a given distribution zone for each quarter of the given determination period.

The total optimal cover is expressed as a percentage of the P50 annual peak demand for the given quarter – which is analogous to a one-in-two-year peak demand referred to in the RRO.

Our proposed approach to account for the triggering of the RRO in the estimated WEC is:

— If the overall level of the optimal contract cover is less than 100 per cent of the P50 annual peak demand, then increase the overall level of contract cover to 100 per cent. This will result in an increase in the WEC value since the cost of the additional contracts will be included.

— If the overall level of the optimal contract cover is equal to or greater than 100 per cent of the P50 annual peak demand then no change is required, and hence the RRO has no impact on the WEC.

**AEMO Direction costs**

Under the National Electricity Rules (NER) AEMO can, if necessary, take action to maintain security and reliability of the power system. AEMO can achieve this by directing a participant to undertake an action – such as directing a generator to operate even though the spot price in the NEM is less than that generator's fuel and variable operating costs. In such instances, compensation may be payable to the participant. This compensation needs to be recovered from other market participants. It is worth noting that such directions issued by AEMO are separate to ancillary services.

There are two types of system security direction:

1. Energy direction – the cost of which is recovered from customers
2. Other direction – the cost of which is recovered from customers, generators, aggregators.

Details of the recovery methodology are provided in AEMO's NEM Direction Compensation Recovery paper published in 2015[4].

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

AEMO publishes the direction cost recovery data on a weekly basis. However, the files are prone to regular updates, as the required information to calculate the amount of compensation becomes available, and its apparent that there is a lag between the time the direction event occurs and final settlement.

AEMO also publish summaries of the costs associated with direction events in their Quarterly Energy Dynamics reports.

To arrive at the estimate of the AEMO Direction compensation costs, ACIL Allen takes the sum of the quarterly Direction costs by region for the most recent past four quarters, as presented in AEMO's latest available Quarterly Energy Dynamics Report (the latest report available at the time

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

of undertaking our analysis for the Determination) and divided by the corresponding annual regional customer energy.

**Costs associated with June 2022 NEM events**

Between 12 and 23 June 2022 a series of events triggered administered pricing, spot market suspension and market interventions in the NEM consistent with the National Electricity Rules (NER). As noted by AEMO in its Compensation Update published on 6 January 2023[5], these events have associated compensation and contract payments, which under the NER are to be recovered from Market Customers (mainly electricity retailers). The costs will be recovered in proportion to energy purchased in each relevant region. Hence these costs should be included in this Determination.

The AEMO Compensation Update published on 6 January 2023 summarises the costs, and groups them into the following categories:

— RERT payments
— Directions compensation
— Suspension pricing compensation
— Administered pricing compensation.

It is important to note that for this Determination, any RERT or Directions costs associated with the June 2022 events will be reported here, and here and excluded from the usual RERT and Directions costs (to avoid double counting).

ACIL Allen has used AEMO's published estimates of the costs of the June 2022 events, as of 6 January 2023. For the more recently compensation amounts published by AEMC in March and April 2023, we have used AEMC's published compensation costs (in $ terms) and allocated them to NEM regions in proportion to energy purchased in each relevant region (in $/MWh terms), in accordance with the National Electricity Rules.

Compensation costs that have been published prior to the 2023-24 Final Determination cut-off date of 10 May 2023 are included in the 2023-24 Final Determination energy costs. Any outstanding compensation amounts published after the cut-off date will be included in the Draft Determination for 2024-25.

**Environmental costs**

**Large-scale Renewable Energy Target (LRET)**

By 31 March each compliance year, the Clean Energy Regulator (CER) publishes the Renewable Power Percentage (RPP), which translates the aggregate LRET target into the number of Large-scale Generation Certificates (LGCs) that liable entities must purchase and acquit under the scheme.

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

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

[5] https://aemo.com.au/-/media/files/electricity/nem/data/mms/2022/june-2022-nem-events-compensation-jan-6.pdf?la=en

***Market-based approach***

A market-based approach is used to determine the price of a LGC, which assumes that an efficient and prudent electricity retailer builds up LGC coverage prior to each compliance year.

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

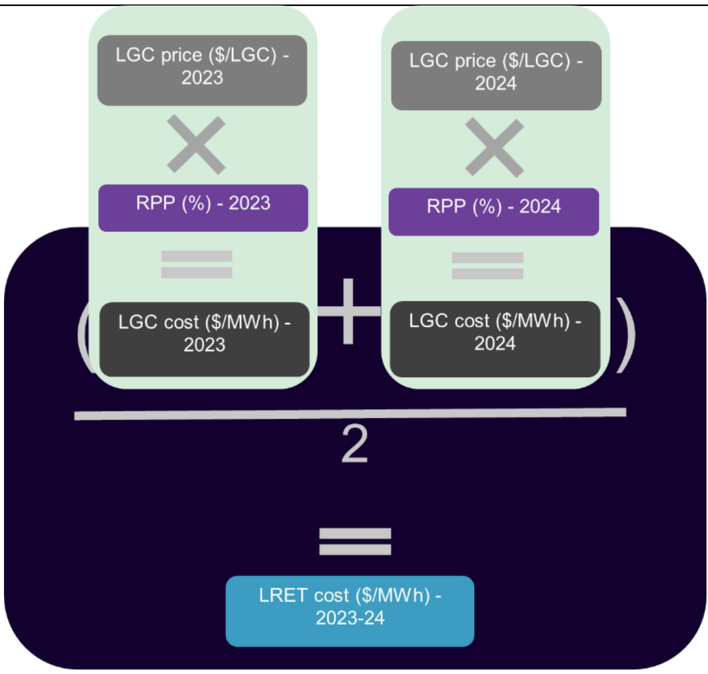
To estimate the costs to retailers of complying with the LRET for 2023-24, ACIL Allen uses the following elements:

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

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

— the estimated Renewable Power Percentage (RPP) for 2024[6].

**Figure 2.9** Steps to estimate the cost of LRET




*Source: ACIL Allen*

**Small-scale Renewable Energy Scheme (SRES)**

Similar to the LRET, by 31 March each compliance year, the CER publishes the binding Small-scale Technology Percentage (STP) for the year and non-binding STPs for the next two years.

The STP is determined ex-ante by the CER and represents the relevant year's projected supply of Small-scale Technology Certificates (STCs) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

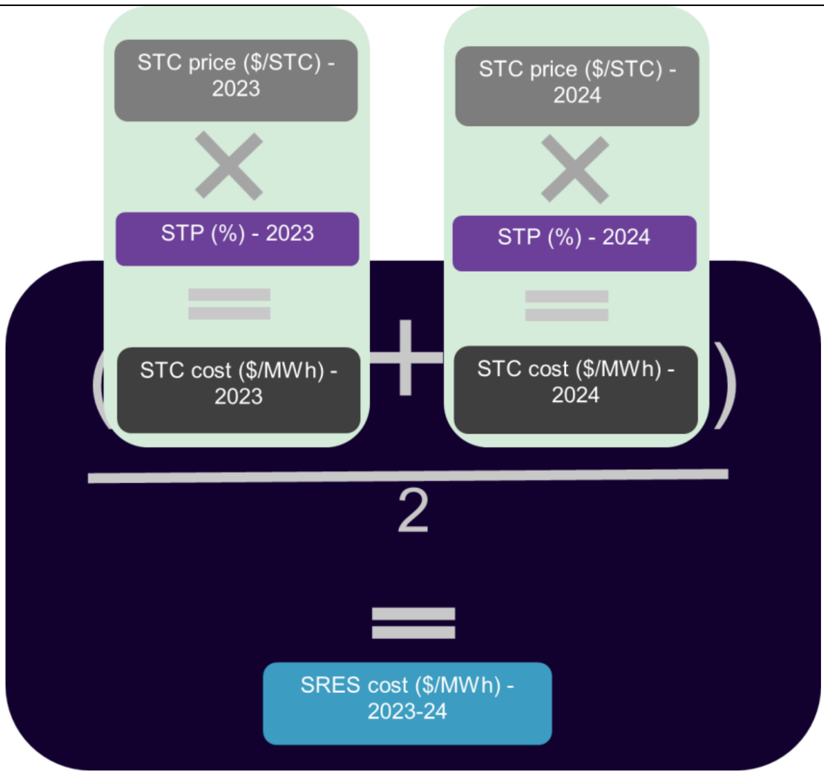
The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

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

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

— the binding Small-scale Technology Percentages (STPs) for 2023 as published by the CER
— an estimate of the STP value for 2024[7]
— CER clearing house price[8] for 2023 and 2024 for Small-scale Technology Certificates (STCs) of $40/MWh.

**Figure 2.10** Steps to estimate the cost of SRES




*Source: ACIL Allen*

### 2.3.4 Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

The components of the wholesale and environmental costs are expressed at the relevant regional reference node (RRN). Therefore, prices expressed at the regional reference node must be adjusted for losses in the transmission and distribution of electricity to customers – otherwise the wholesale and environmental costs are understated. The cost of network losses associated with wholesale and environmental costs is separate to network costs and are not included in network tariffs.

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

[8] 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.

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

The loss factors used are published by AEMO one year in advance for all NEM regions. Average transmission losses by network area are estimated by allocating each transmission connection point to a network based on their location. Average distribution losses are already summarised by network area in the AEMO publication.

As described by AEMO[9], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

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

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

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

# Updated spot price simulations 3

ACIL Allen has updated its spot price simulations for the Final Determination. As noted in our report for the Draft Determination, we regularly re-assess our spot market assumptions – assessing and accounting for any warranted changes to the input assumptions. We have done this for each previous QCA engagement.

The key input assumption change adopted in the updated simulations for the Final Determination is the treatment of the coal and gas price caps.

The market simulations for the Draft Determination were completed at the end of December 2022. At that stage the coal and gas price caps had only been recently announced by federal and state governments.

ACIL Allen's in house power market simulation model, PowerMark, was used to produce the 561 annual sets of simulated hourly prices for each of the NEM regions. Details of PowerMark are provided in **Figure 2.6**. PowerMark allows each portfolio of generators to dynamically construct an offer curve for each hour modelled. The shape of the offer curve is adjusted in an iterative round-robin game - allowing each portfolio to attempt to maximise its net uncontracted revenue for the given hour.

The fuel price is an important factor in the construction of the initial offer curve and directly influences the simulated price outcomes.

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

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

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

## 3.1 Coal plant

ACIL Allen has observed some changes in bidding behaviour by the coal fired plant since the implementation of the coal price caps. However, the changes are different for each station:

— ACIL Allen understands that Eraring is currently purchasing coal on a shorter-term basis. It can be seen that a portion of its offers have decreased from around $150-$300/MWh to $70-

$100/MWh with implementation of the coal price cap – but this is above the $60-70/MWh range. Given Eraring purchases coal on a short-term basis it may be the case that it is preserving its coal by bidding in at prices above the $60-70/MWh range to avoid shortfalls.

— The Queensland Government-owned CS Energy has dispatch rights to the majority of the Gladstone power station. Similar to Eraring, it can be seen that a portion of Gladstone's offers have decreased from around $150-$300/MWh to $60-$70/MWh with implementation of the coal price cap – up until mid to late February, at which point the offer price has increased to above $300/MWh.

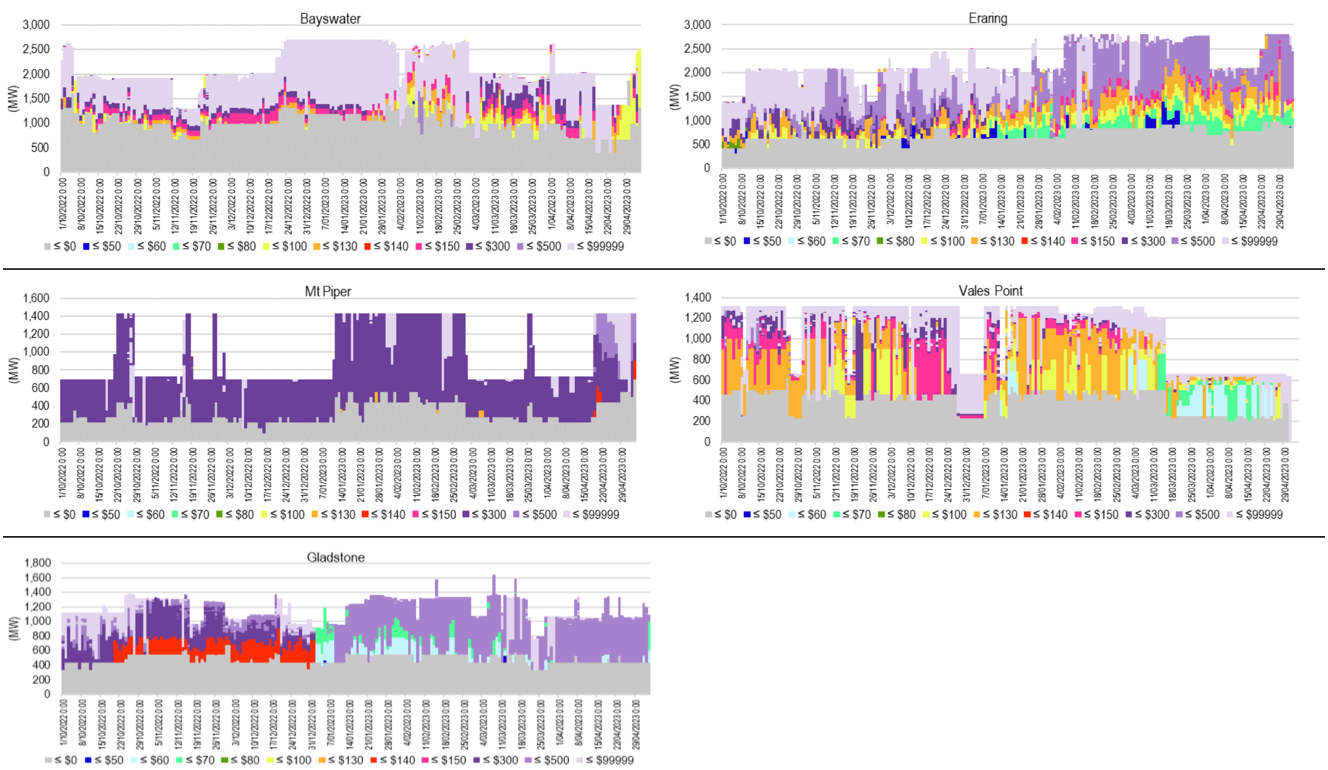
— Bayswater and Vales Point have reduced the price of a portion of their offer curve since the implementation of the coal price cap – but it remains above the $60-70/MWh range. This may be a result of maximising the value of its generation. Vales Point has reduced its offer price further over the past two months, but this coincides with maintenance at one of its units, and may be doing this to manage contractual obligations.

— Mount Piper is short on coal and hence tends to offer its capacity at a much higher price (aside from its minimum stable load) to avoid shortfalls. ACIL Allen understands that Mount Piper has recently secured additional coal supply, but it is unclear if this is sufficient for the station to run at a high capacity factor.

The key point of this high-level analysis is that the implementation of the coal price cap to date has not had a uniform impact on the bidding behaviour of the coal fired power stations. The coal price cap has not resulted in all stations bidding in their contracted capacity at the $60-$70/MWh price range. Whereas ACIL Allen's modelling had assumed a uniform impact for the Draft Determination.

Actual offer curves from October 2022 to April 2023 for coal plant are shown in Figure 3.1.

**Figure 3.1** Actual offer curves of coal fired power stations – October 2022 to April 2023




*Source: ACIL Allen analysis of AEMO data using NemSight*

## 3.2 Gas plant

ACIL Allen has observed some changes in bidding behaviour by the gas fired plant since the implementation of the gas price caps. However, the changes are different for each station:

— Swanbank E displays the largest change – reducing the offer price of the portion of its contracted capacity from about $130/MWh to the $80-$100/MWh range.

— Pelican Point has reduced its offer price – but not to the same extent as Swanbank E.

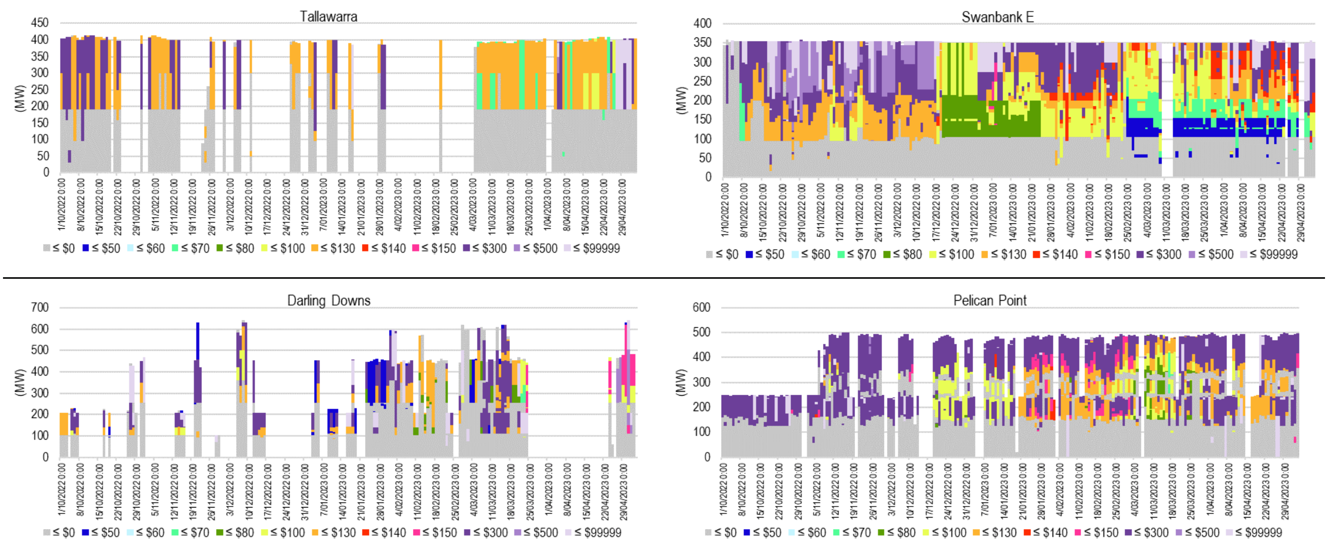
— There is not a discernible change in offer price of Tallawarra and Darling Downs.

— The gas fired peaking plant do not appear to have adjusted their offer curves either.

Gas plant, in particular, gas peaking plant rely to some extent on purchases of gas from the short term markets which are exempt from the gas price cap. Generators may offer their capacity into the NEM at the cost of their marginal gas, to avoid over consumption of gas beyond contracted volumes, and hence the exemption of spot gas from the price cap appears to have resulted in a less obvious impact of the gas price cap on bidding behaviour to date.

Actual offer curves from October 2022 to April 2023 for gas plant are shown in Figure 3.2 and Figure 3.3.

**Figure 3.2** Actual offer curves of CCGTs – October 2022 to April 2023




*Source: ACIL Allen analysis of AEMO data using NemSight*

**Figure 3.3** Actual offer curves of peaking plant – October 2022 to April 2023

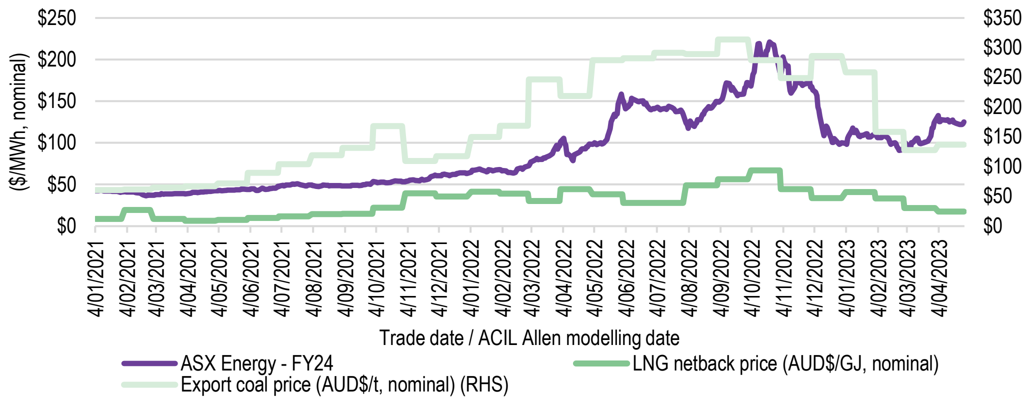

*Source: ACIL Allen analysis of AEMO data using NemSight*

## 3.3 ASX Energy futures market

Given the influence of fuel prices on generator offer curves and hence wholesale electricity spot prices, it is not surprising that there is a relationship between the electricity futures market prices and fuel prices.

Shown below is the relationship between daily settled Queensland futures prices for the 2023-24 financial year versus the monthly average export coal price and LNG netback price. Similar trends hold true for quarterly ASX contract products.

**Figure 3.4** 2023-24 strip ASX Energy price versus export coal and LNG netback prices – Queensland

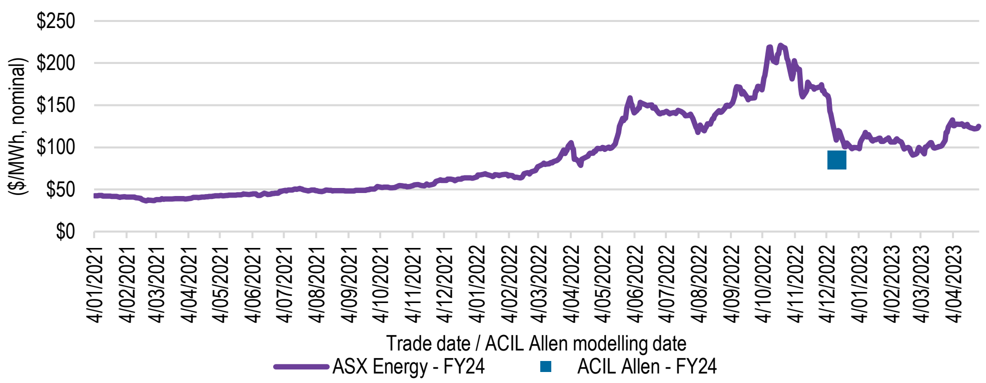



*Source: ACIL Allen analysis of ASX Energy, ACCC and Argus data and reports*

The chart below shows the average spot price in Queensland across the 561 annual simulations produced by ACIL Allen for the Draft Determination in comparison with the futures market.

For the Draft Determination the average simulated price was about $85/MWh. At the time the simulations were undertaken the future contract price was in sharp decline and was at about $110/MWh. However, it can be seen that the decline in futures contract prices ceased at that point, and since then have increased to about $125/MWh.

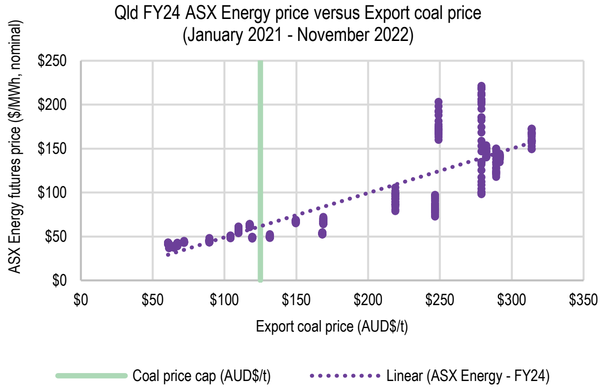
**Figure 3.5** 2023-24 strip ASX Energy price versus ACIL Allen's average spot price from the 561 simulations for the Draft Determination – Queensland

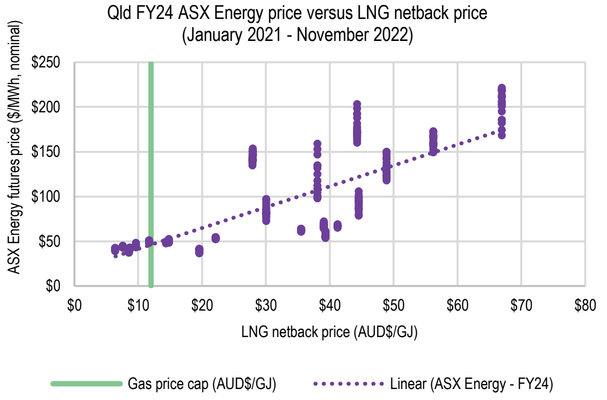



*Source: ACIL Allen analysis of ASX Energy and ACIL Allen modelling*

Although our simulated price was less than the futures contract price, the impact of the coal and gas price caps was yet to be observed in the spot market. Further, the charts below show that the average of the simulated spot price was not dissimilar to where the futures market price was when coal and gas prices were previously close to the price cap levels. On this basis, ACIL Allen was comfortable with the simulated prices at the time of the Draft Determination.

**Figure 3.6** FY24 strip ASX Energy price versus export coal and LNG netback prices – Queensland




*Source: ACIL Allen analysis of ASX Energy, ACCC and Argus data and reports*

ACIL Allen continues to hold the view that the spot price simulations ought to be based on observable market fundamentals. This means we do not attempt to arbitrarily match the futures price at any point in time. That said, we recognise the futures market represents a consensus view and any large difference between the spot price simulations and the futures market needs to be considered.

Regardless of the intent of the coal and gas price caps, it is apparent that participants in the futures market are not expecting the implementation of the coal and gas price caps to have uniform impact on the bidding behaviour of coal and gas fired generators – for the observable reasons outlined in the previous sections. This is not to say that the coal and gas price caps have not decreased spot price outcomes or futures contract prices to date – they have, but just not to the same extent that ACIL Allen had assumed at the time it undertook the spot price simulations for the Draft Determination.

Given the availability of observable market data since the Draft Determination, ACIL Allen has updated its spot market simulations by making the following assumptions changes within PowerMark for the Final Determination:

— All coal plant, except Mount Piper, are assumed to have ready access to coal at prices capped at $125/t and hence bid in their portion of their capacity on this basis.

— Mount Piper is assumed to continue to be short on coal and hence offer its capacity into the market on an energy constrained basis.

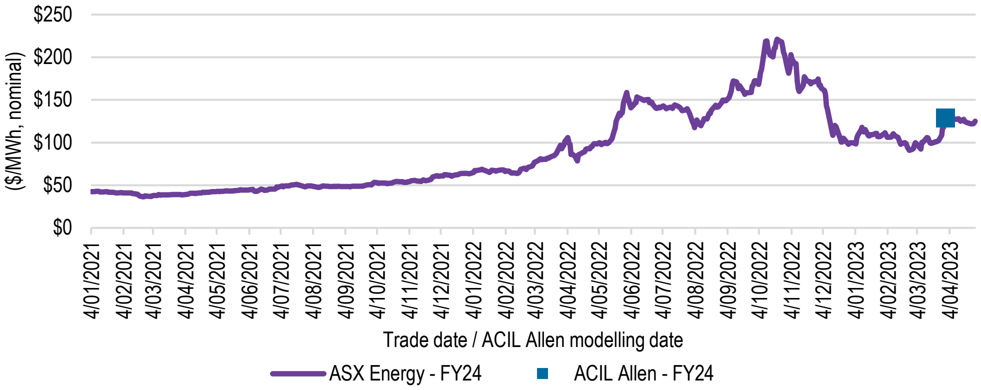
— CCGTs are assumed to have ready access to gas prices capped at $12/GJ and hence bid in their contracted portion of their capacity on this basis.

— The other gas plant are assumed to base their offer curves on the cost of gas from the short term markets at an average price of $25/GJ (based on a LNG netback price of $22/GJ plus $3/MWh for delivery).

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

The resulting simulated spot price outcomes for the Final Determination are about $40/MWh higher than those of the Draft Determination. This is a large increase, but given we are calculating a hedged price outcome, the update results in about a $7-$10/MWh increase for the various WECs compared with the Draft Determination.

**Figure 3.7** 2023-24 strip ASX Energy price versus ACIL Allen's average spot price from the 561 simulations for the Final Determination – Queensland




*Source: ACIL Allen analysis of ASX Energy and ACIL Allen modelling*

# Responses to submissions to Draft Determination 4

The QCA forwarded to ACIL Allen eight submissions in response to its Draft Determination. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration for the 2023-24 Draft Determination. A summary of the review is shown below in Table 4.1.

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

— Hedging strategy
— Wholesale spot price simulations
— June 2022 event compensation costs.

**Table 4.1** Review of issues raised in submissions in response to the Draft Determination

| ID | Stakeholder | Wholesale energy costs | Contract prices /hedge model | Renewable energy policy costs | NEM fees and other costs | Prudential costs | Energy losses |
|---|---|---|---|---|---|---|---|
| 1 | Canegrowers | Nil | Nil | Nil | Nil | Nil | Nil |
| 2 | Cotton Australia | Nil | Nil | Nil | Nil | Nil | Nil |
| 3 | Ergon Energy Retail | Yes | Yes | Nil | Nil | Nil | Nil |
| 4 | J. Glen | Nil | Nil | Nil | Nil | Nil | Nil |
| 5 | J. Pownall of PC Farming | Nil | Nil | Nil | Nil | Nil | Nil |
| 6 | N. Mason | Nil | Nil | Nil | Nil | Nil | Nil |
| 7 | Queensland Farmers Federation | Nil | Nil | Nil | Nil | Nil | Nil |
| 8 | Waste and recycling industry of Queensland (WRIQ) | Nil | Nil | Nil | Yes | Nil | Nil |

*Note: Yes = an issue was raised that required ACIL Allen's consideration*
*Source: ACIL Allen analysis of QCA supplied documents*

## 4.1 Hedging strategy

Ergon Energy Retail (EEQ) states on page one of its submission that the

*percentage of assumed cap contract volume in the hedging portfolio on several occasions as we consider this assumed volume would be practically unachievable for an electricity retailer in the electricity market.*

*In the 2023-24 draft determination ACIL Allen has further increased their modelled use of caps despite their acknowledgement there has been no increase in the cumulative trade volume of caps. EEQ remains of the view that the more accurate indicator of the availability of caps for retailers is the ASX open interest position. We suggest some proportion of the assumed cap contract volume should be replaced with swaps in the modelled hedging portfolio. EEQ notes that, on average, the ASX open interest position for caps is only 11% of the ASX open interest position for swaps, whereas ACIL Allen has an assumed cap contract volume that is, on average, 248% larger than its assumed swap contract volume.*

### 4.1.1 ACIL Allen response

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

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

There was a noticeable change in the weighting of cap contracts relative to base swap contracts in the 2022-23 determination. This is because it was apparent that peak contracts were no longer being routinely used (or traded). This meant that the peak contracts had to be replaced by more base swaps or caps (or a combination of the two) or an increased exposure to the spot market price. There are pros and cons as to which approach a retailer may take. Increasing the level of base swaps (and holding the cap cover level the same) may reduce the variability in the WEC but increases the overall WEC to a point that the retailer no longer remains competitive.

## 4.2 Wholesale spot price simulations

EEQ noted that the spot price simulations for the Draft Determination were at a level lower than that of current price levels and the futures market. We are cognisant of this observation and its implications on the WEC estimates.

### 4.2.1 ACIL Allen response

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

The implementation of the coal and gas price caps were in their infancy when the spot price simulations for the Draft Determination were undertaken. ACIL Allen has updated its spot price simulations for the Final Determination. The key input assumption change adopted in the updated simulations for the Final Determination is the treatment of the coal and gas price caps. Details of this change are provided in chapter 3.

## 4.3 June 2022 event compensation costs

On page 6 of its submission, the Waste and Recycling Industry of Queensland (WRIQ) states:

*The methodology applied for calculating compensation costs is not transparent in the Draft Determination.*

*WRIQ notes that AEMOs costs (for compensation for market events, namely the activation of the Reliability and Emergency Reserve Trader in June and July 2022) are now known and have been included in the Draft Determination. However, that the costs from the AEMC for these events are still outstanding.*

*WRIQ submits that any additional costs for the outstanding AEMC compensation are not added to electricity costs (either this year nor carried over to next year) and instead, if required, funded through consolidated revenue given their relatively small materiality. It is WRIQ's concern that networks may experience another event similar to that experienced in June 2022 and a longer-term strategy for dealing with these deviations and associated compensation charges must be determined, particularly for customers in regional Queensland whose treatment should be different from SEQ customers.*

#### 4.3.1 ACIL Allen response

For the Draft Determination, we used AEMO's published estimates of the costs of the June 2022 events as of 6 January 2023[10]. For the more recent compensation amounts published by AEMC in March and April 2023, we have taken AEMC's published compensation costs and allocated them to NEM regions in proportion to energy purchased in each relevant region, in accordance with the National Electricity Rules.

The National Electricity Rules (NER) provide the process and formulae for AEMO to recover the compensation payable from market customers in the region affected by the imposition of an administered price.

Compensation costs that have been published prior to the 2023-24 Final Determination cut-off date of 10 May 2023 will be included in the 2023-24 Final Determination energy costs. Any outstanding compensation amounts published after the cut-off date will be included in the Draft Determination for 2024-25.

10 The latest June 2022 NEM Events Compensation Update can be accessed via:

https://aemo.com.au/-/media/files/electricity/nem/data/mms/2022/june-2022-nem-events-compensation-jan-6.pdf?la=en

# 5 Estimation of energy costs

## 5.1 Introduction

In this chapter we apply the methodology described in Chapter 2, and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the load profiles for 2023-24.

### 5.1.1 Historic demand and energy price levels

Figure 5.1 shows the average time of day spot price for the Queensland region of the NEM, and the associated average time of day load profiles for the past 12 years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the profiles.

Wholesale electricity spot prices in Queensland for 2021-22 more than doubled those of 2020-21, increasing by about $100/MWh when compared with 2020-21, from about $62/MWh to about $162/MWh. This is despite the continued uptake of rooftop PV putting downward pressure on price outcomes during daylight hours. The main reasons for the increase in prices overall are the:

- substantial increases in coal costs for the New South Wales and Queensland coal fired power stations that are exposed to the export coal market which experienced an increase in price from about USD$150/t in July 2021 to about USD $400/t in June 2022 due to the:
  - war in Ukraine and subsequent embargo of Russian trade in thermal coal
  - supply from some producers being voluntarily curtailed in late 2020 in response to the low export prices
  - a number of weather events also impacted coal supply chains
  - domestic reservation policies being invoked in Indonesia placing further pressure on supply.
- increase in coal price increased NEM spot price outcomes overnight and during the day when coal was at the margin.
- increase in gas costs across the NEM due to the strong increase in LNG netback (export) prices from around AUD$11/GJ in July 2021 to about AUD$40/GJ by May 2022, which increased NEM spot prices during the evening peak when gas was at the margin.
- continued outage of Callide C Unit 4 as well as other plant outages (such as Kogan Creek in the first quarter of 2022) which contributed to an increase in price volatility across the evening peak periods.

In 2022-23 to date:

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

- LNG netback prices in the first quarter of 2022-23 continued to grow to a peak of about AUD$70/GJ in October 2022, and have since declined to about AUD$25/GJ.
- This has resulted in wholesale electricity prices averaging around $149/MWh in Queensland to date (1 July 2022 to 30 April 2023).
- We have seen some impacts of the Government's December 2022 intervention of capping coal and gas prices, on wholesale electricity spot prices (See Chapter 3).

In relation to each profile, we note the following:

- The annual time of day price profile has been volatile over the past decade – with the overall level and shape of the price profile changing from one year to the next. For example, in 2021-22 the time-of-day profile was much more volatile compared with the very flat profile of 2011-12.
- Wholesale electricity spot prices have generally peaked in the afternoon and evening, and this has become more pronounced in recent years with the continued uptake of rooftop PV and the commissioning of utility scale solar.
- In 2021-22, prices during daylight hours initially decreased due to further rooftop PV uptake and commissioning for utility scale solar increasing the propensity for solar (and wind) to be at the margin, but these were offset by thermal power station outages in the second part of the year which meant less generation being offered at $-1,000/MWh[11], and hence reduced the propensity for renewables to be at the margin. The increase in coal prices also meant the prices during daylight hours increased when coal was at the margin.
- The higher gas prices in the second half of 2021-22 increased wholesale electricity spot prices during the evening peak to levels not observed before – averaging around $600/MWh.
- In short, the profile of wholesale electricity spot 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 varies 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 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. That said, with a continued decrease in prices during daylight hours (due to continued rooftop PV uptake), costs of tariff 33 may well converge with those of tariff 31 over time.
- Between 2011-12 and 2019-20, the Energex NSLP and the Ergon NSLP load profiles, experienced a carve out of load during daylight hours with the increased penetration of rooftop solar PV. This resulted in the load profile becoming peakier over time and consequently, the demand weighted spot prices[12] (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP). The carving out of the

[11] Coal fired power stations typically offer their minimum stable load (which is about 40 per cent of their capacity) at the market price floor to avoid being dispatched below critical stable levels.

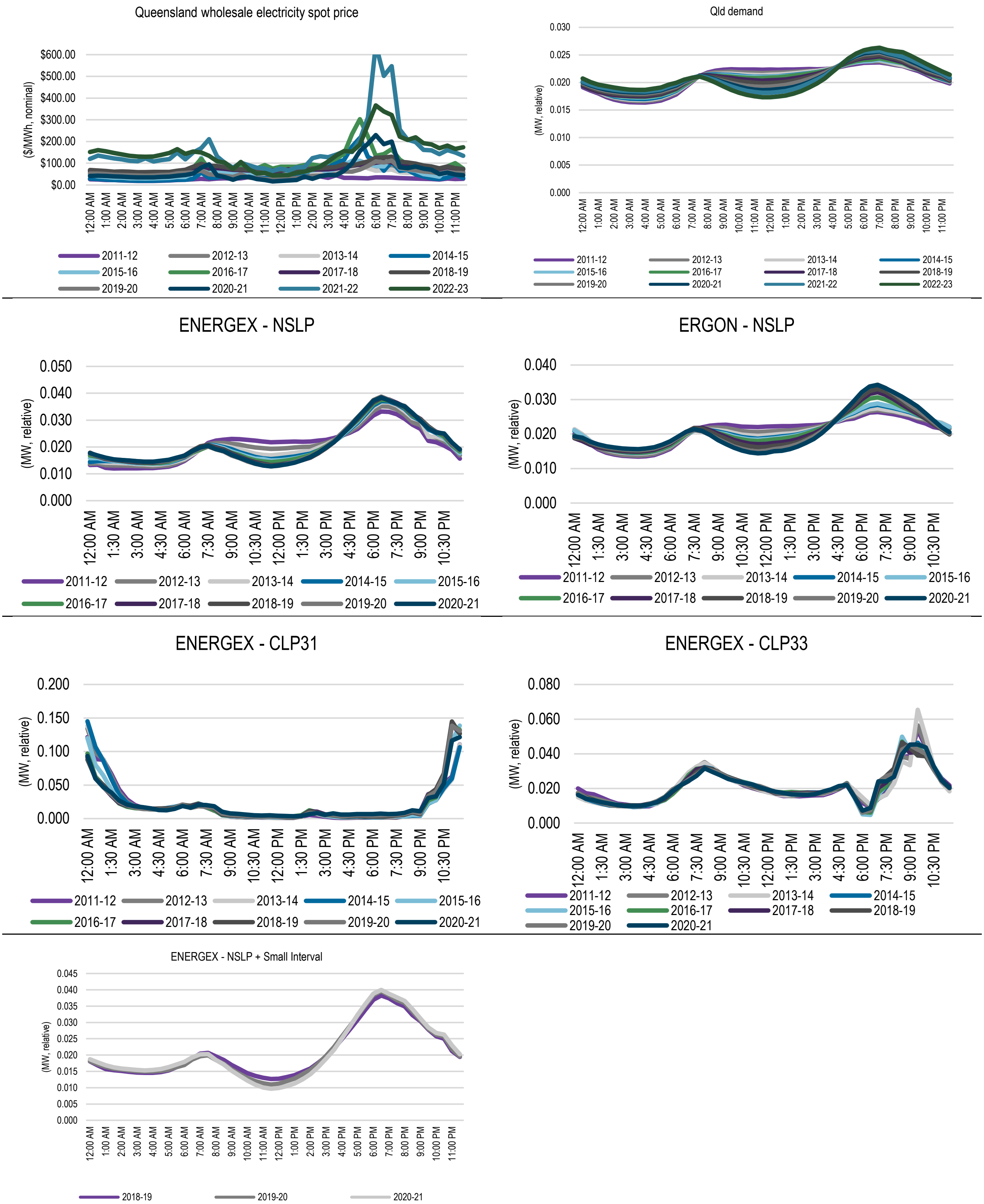
[12] The demand weighted price is in effect the unhedged wholesale energy cost that the retailers pay AEMO for the NSLP.

NSLPs during daylight hours increases the relative weighting of the load profile during the higher priced evening peak and reduces the relative weighting during the lower priced daylight hours.

— However, over the past few years the rate of carve out of the NSLP load during daylight hours has slowed, and this is most likely due to new rooftop solar PV installations being paired with the installation of interval meters – removing those consumers from the NSLP.

— For this reason, data has been obtained for residential and small business customers on interval meters, and it can bee seen that when combining the NSLP and interval meter data, the trend in carve out of demand during daylight hours has continued over the past few years.

**Figure 5.1** Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2011-12 to 2022-23




Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of the load profile, not its absolute size, which determines its wholesale energy cost. 2022-23 price and Queensland demand series includes data up to January 2023. Insufficient or unresolved NSLP/CLP/interval meter load data available for 2021-22 and 2022-23 and hence excluded.

*Source: ACIL Allen analysis of AEMO data*

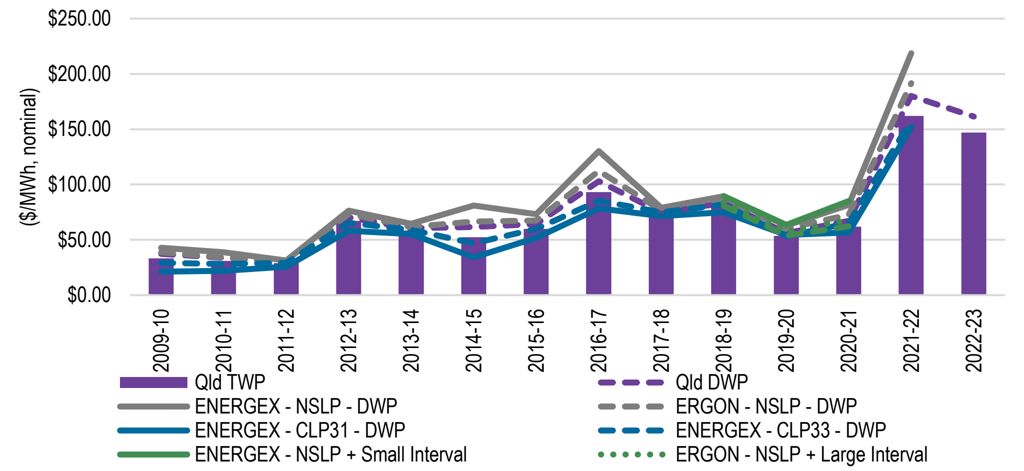
Figure 5.2 shows the actual annual demand weighted spot price (DWP) for each of the profiles compared with the time weighted average spot price in Queensland (TWP) over the past 12 years. The DWP for the Energex NSLP is at a 20 per cent premium to the TWP on average over the past five years, compared with an average premium of about 15 per cent for the Ergon NSLP over the same period. The combined load profile of the Energex NSLP and residential small business customers on interval meters is at a 23 per cent premium to the TWP.

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 12 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 they are used to manage network congestion – hence their shape is not purely a result of consumer behaviour.

Although AEMO is yet to publish sufficient load data for the NSLPs for 2022-23, based on the observed premiums of the DWP to TWP over the past five years, it is likely the DWPs for the NSLPs combined with interval meter loads in 2022-23 will be between $180 and $220/MWh, compared with $70-$80/MWh in 2020-21.

**Figure 5.2** Actual annual average demand weighted price ($/MWh, nominal) by profile and Queensland time weighted average price ($/MWh, nominal) – 2009-10 to 2022-23




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

*Source: ACIL Allen analysis of AEMO data*

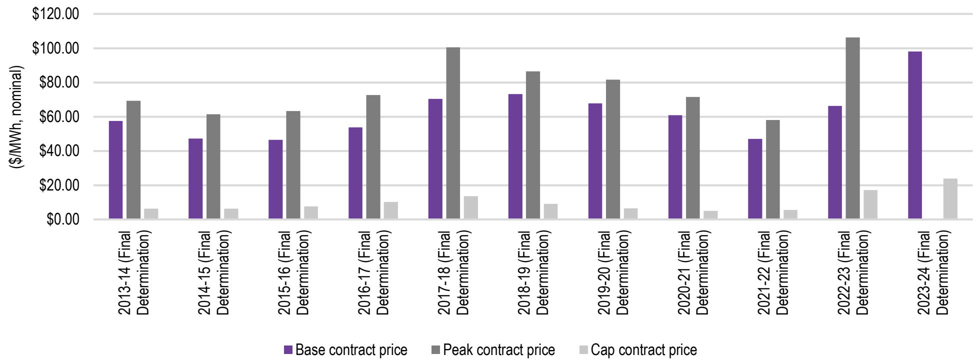
The volatility of spot prices (timing and incidence) provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) used in the methodology does not change from one year to the next, although the mix does. The movement in contract price is a key contributor to movement in the estimated wholesale energy costs of the different profiles year on year.

Figure 5.3 shows that compared with 2022-23, futures base contract prices for 2023-24, on an annualised and trade weighted basis to date, have increased by about $32/MWh for Queensland. Cap contract prices have increased by nearly $6/MWh.

Unlike the previous four determinations spanning 2018-19 to 2021-22 in which there was a clear decline in contract prices, the market is clearly expecting higher price outcomes experienced in 2022-23 to continue into 2023-24, due to the relatively stronger coal and gas costs, coupled with the closure of Liddell in New South Wales, more than offsetting the amount of utility scale renewable investment coming on-line between 2022-23 and 2023-24. Although the Government's intervention on coal and gas prices has reduced the market's expectations on wholesale electricity wholesale spot prices for 2023-24, the trade weighted average futures prices remain elevated relative to 2022-23 since a large portion of hedges were purchased prior to the announcement of the Government's intervention.

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

**Figure 5.3** Queensland Base, Peak, and Cap trade weighted average contract prices ($/MWh, nominal) – 2013-14 to 2023-24




*Source: ACIL Allen analysis of ASX Energy Data*

## 5.2 Estimation of the Wholesale Energy Cost

### 5.2.1 Estimating contract prices

Contract prices for the 2023-24 year were estimated using the trade-weighted average of ASX Energy settlement prices of individual trades of contracts and exercised base call[13] options (including the trade weighted average premium for exercised and expired base options) since the contract was listed up until 10 May 2023 inclusive. The inclusion of exercised options' strike prices and option premiums in this determination is a refinement of the methodology and reflects the increasing use of options in the futures market over the past 12-18 months. To date, exercised base options contribute about 15 per cent of the traded volume of base 2023-24 contracts.

Table 5.1 shows the estimated quarterly swap and cap contract prices for 2022-23 and 2023-24. Base contract prices have increased from 2022-23 to 2023-24 by about 55 per cent. And there are very strong increases in cap prices across all quarters – averaging over 44 per cent.

[13] We exclude put options since these are not ordinarily used by retailers as part of hedging their retail load.

**Table 5.1** Estimated contract prices ($/MWh, nominal) - Queensland

| | Q3 | Q4 | Q1 | Q2 |
|---|---|---|---|---|
| | | 2022-23 | | |
| Base | $58.31 | $59.76 | $78.22 | $57.43 |
| Cap | $13.32 | $15.04 | $29.53 | $8.31 |
| | | 2023-24 | | |
| Base | $102.68 | $90.29 | $115.32 | $85.40 |
| Cap | $20.02 | $22.05 | $37.20 | $17.88 |
| | | Percentage change from 2022-23 to 2023-24 | | |
| Base | 76% | 51% | 47% | 49% |
| Cap | 50% | 47% | 26% | 115% |

*Source: ACIL Allen analysis using ASX Energy*

The following charts show daily average settlement prices and trade volumes for 2023-24 ASX Energy quarterly base futures and cap contracts up to 10 May 2023.

There is little or no trade in peak contracts which is not surprising given the carve out of demand during daylight hours. The traditional definition of the peak period (7am to 10pm weekdays) appears to be no longer relevant to market participants when considering managing spot price risk. Hence peak contracts are excluded from the analysis and are assumed not to contribute to the hedge portfolio.

The announcement of the Government intervention in the form of coal and gas price caps has coincided with a decline in futures prices of between $50 and $100/MWh (depending on the quarterly product). However, given most trades (to date) occurred prior to the announcement of the intervention in December 2022, the trade weighted average futures price has tended to stabilise rather than decrease since the announcement.

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

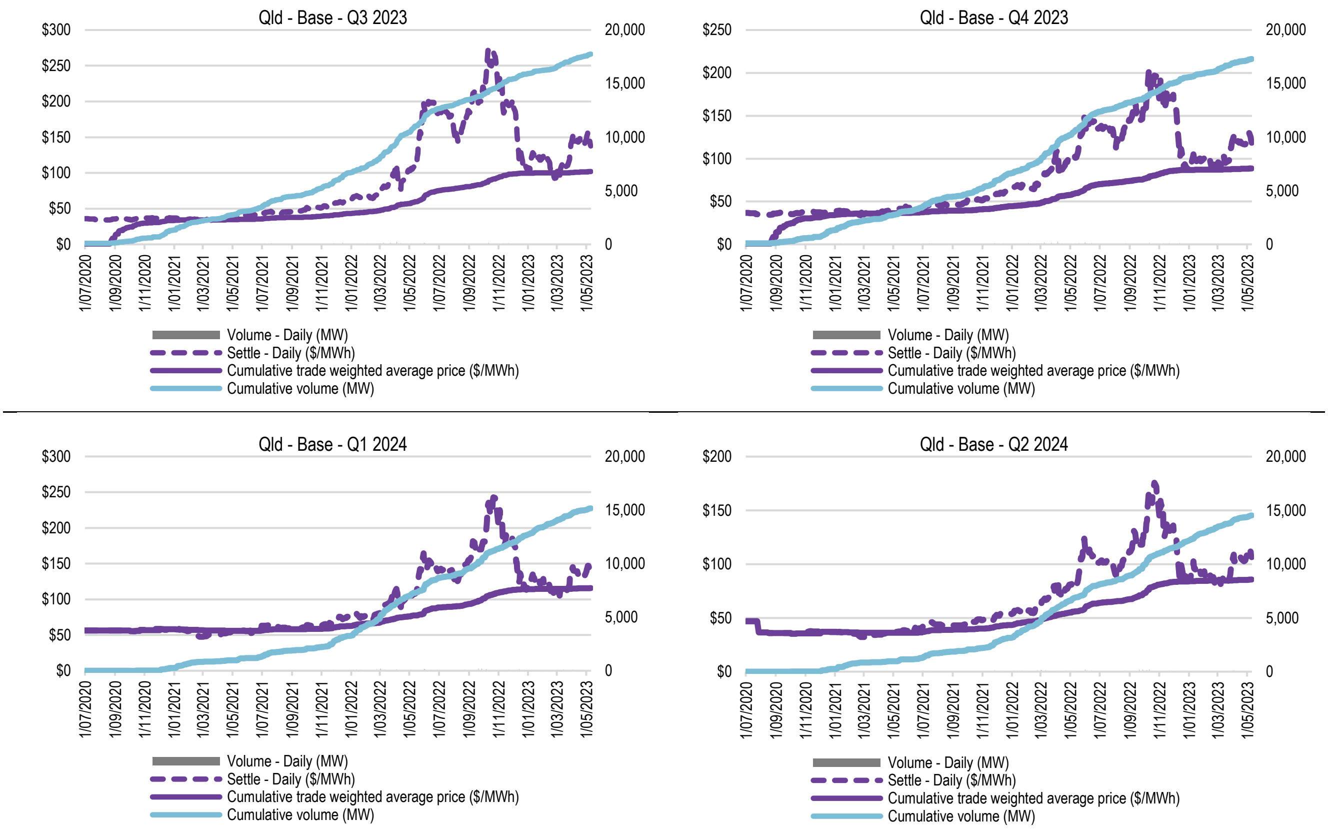
Indeed, contract prices have increased slightly since the Draft Determination. This could be for several reasons, including:

— the further delay in return to service of Callide C

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

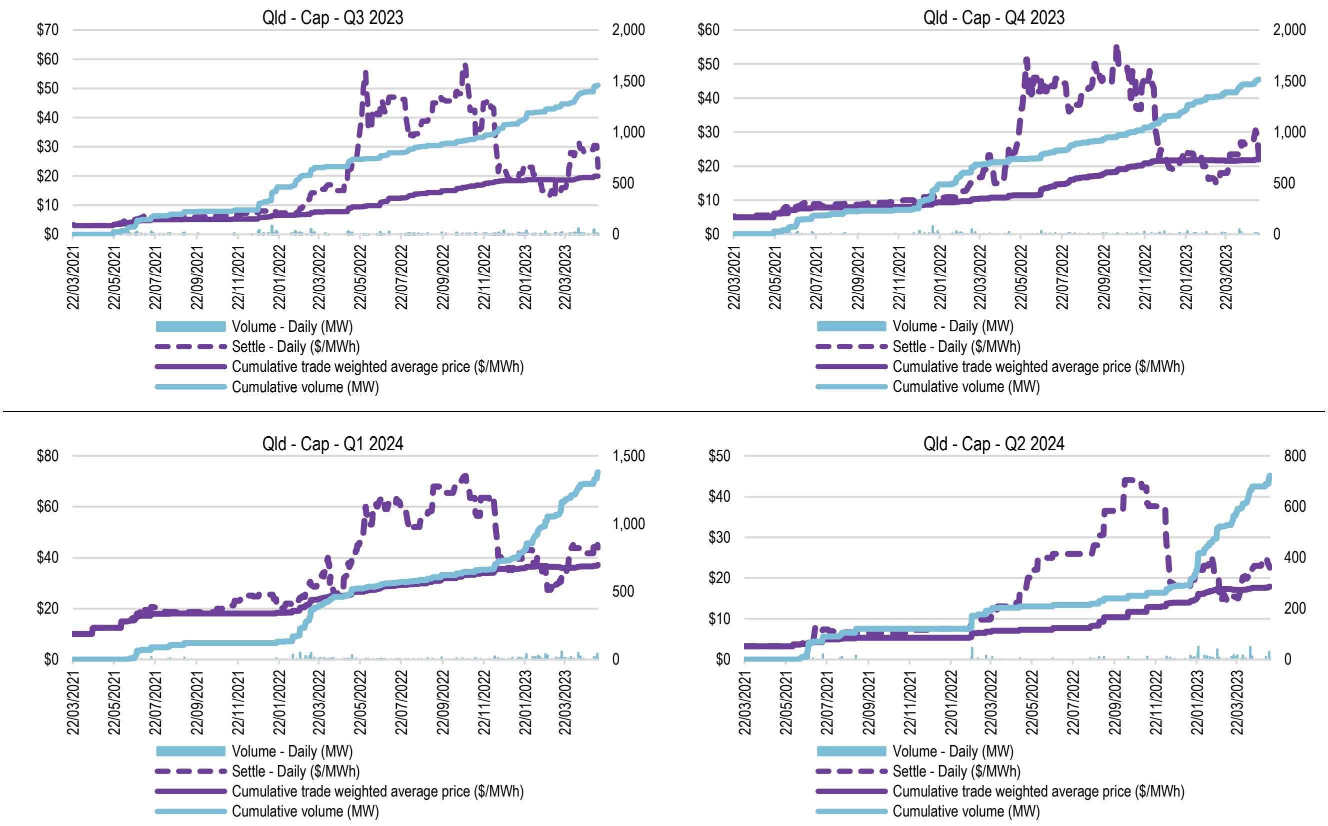
— the expectation of a return to El Nino in 2023-24 and its associated impact on extreme weather driven demand outcomes.

**Figure 5.4** Time series of trade volume and price – ASX Energy base futures - Queensland




*Source: ASX Energy data*

**Figure 5.5** Time series of trade volume and price – ASX Energy $300 cap futures - Queensland



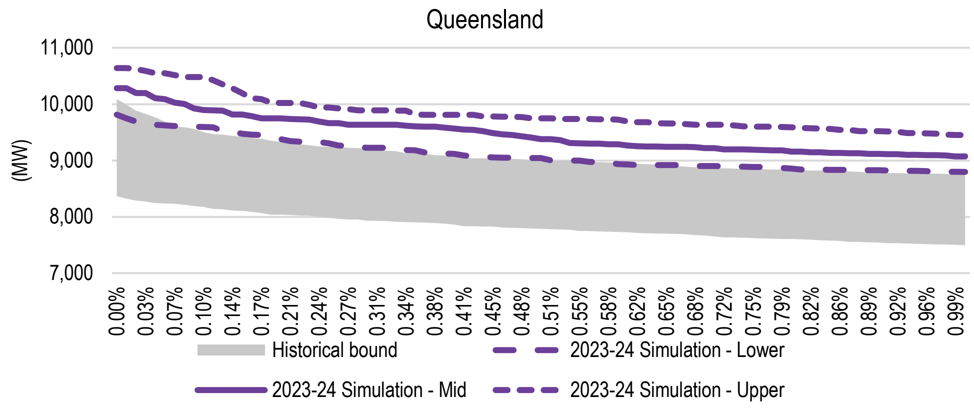

*Source: ASX Energy data*

### 5.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly spot prices for the 561 simulations (51 demand and 11 outage sets).

Figure 5.6 shows the range of the upper one percent segment of the demand duration curves for the 51 simulated Queensland system demand sets resulting from the methodology for 2023-24, along with the range in historical demands since 2011-12. The simulated demand sets represent the upper, lower, and middle of the range of demand duration curves across all 51 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2023-24 have a variation similar to that observed over the past five years - that is, the variation between the simulated demand sets does not just occur at the single peak annual demand but across a reasonable portion of the demands within the given simulation. This variation in demand contributes to the variation in modelled spot price outcomes as discussed further in this section.

**Figure 5.6** Comparison of upper one per cent of hourly loads of 2023-24 simulated hourly demand sets with historical outcomes – Queensland




*Source: ACIL Allen analysis and AEMO data*

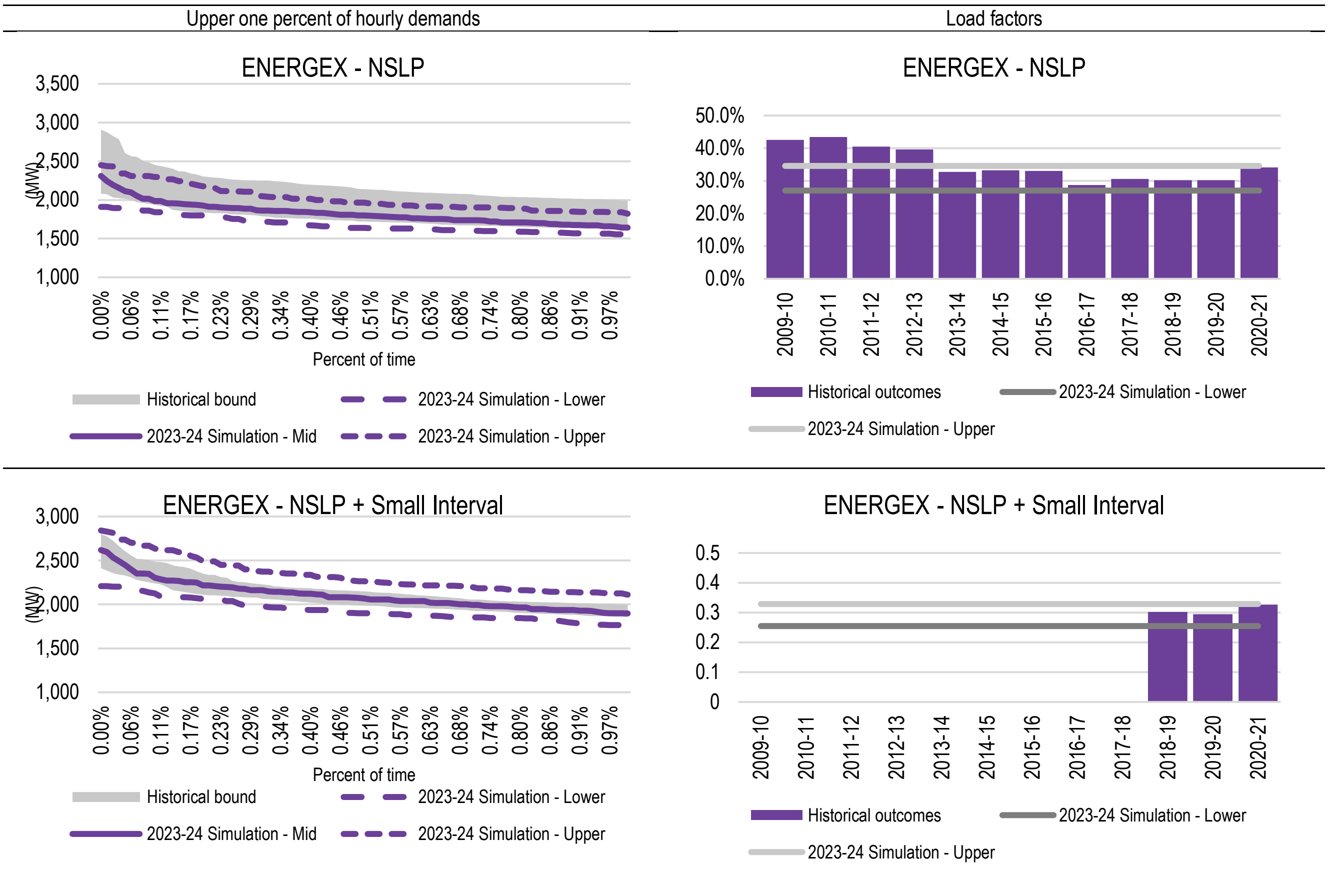
We do not expect the simulated demand sets to line up perfectly with the historical demand sets, in terms of their absolute location. For example, the simulated demand sets for 2023-24 are generally higher than the pre-2016-17 observed demand outcomes in Queensland due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone. Further, the demand forecast for 2023-24 from AEMO's ESOO/ISP includes some growth due to the commencement of electrification in some sectors of the economy. What is important, is that the range in simulated outcomes reflects the range experienced in the past, indicating that the methodology is accounting for an appropriate degree of uncertainty.

The left panels of Figure 5.7 shows the range of the simulated NSLP and interval meter peak demands for residential and small business customers envelope recent actual outcomes. This variation results in the annual load factor[14] of the 2023-24 simulated demand sets ranging between 25 percent and 33 percent compared with a range of 29 percent to 33 percent for the actual Energex NSLP and small customer interval meter demands (as shown in the right panels of Figure 5.7). There was an observable fall in the load factor in the actual NSLP between 2010-11 and 2016-17 due to an increase in penetration of rooftop solar PV panels. However, it is fair to say this reduction has slowed in the past few of years – which may well be related to recent rooftop PV installations being associated with meter upgrades (from accumulation to interval meters) or changes in demand patterns due to COVID-19 restrictions. At this stage we have access to three years of small customer interval meter data and although the load factor has not decreased, the carve out of demand during daylight hours has continued over the past three years (as shown earlier in Figure 2.3)

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.

[14] 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 5.7** Comparison of upper one per cent of hourly loads and load factors of 2023-24 simulated hourly demand sets with historical outcomes – Energex NSLP and small interval meter load




*Source: ACIL Allen analysis and AEMO data*

The chart in the upper left panel of Figure 5.8 compares the modelled annual regional TWP for the 561 simulations for 2023-24 with the regional TWPs from the past 10 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential spot price outcomes for 2023-24 when compared with the past 10 years of history.

Comparing the upper one percent of hourly prices from the simulations with historical spot prices (the upper right panel in Figure 5.8) shows the spread of the hourly prices from the simulations also more than adequately covers the historical spread of spot prices. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

ACIL Allen is satisfied that PowerMark has performed adequately in capturing the extent and level of high price events based on the demand and outage inputs for the 561 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh (shown in the mid left panel of Figure 5.8) for the 561 simulations is consistent with those recorded in history. For some of the 2023-24 simulations the contribution of price spikes is greater than historical levels, reflecting the general tightening of the demand-supply balance in the market.

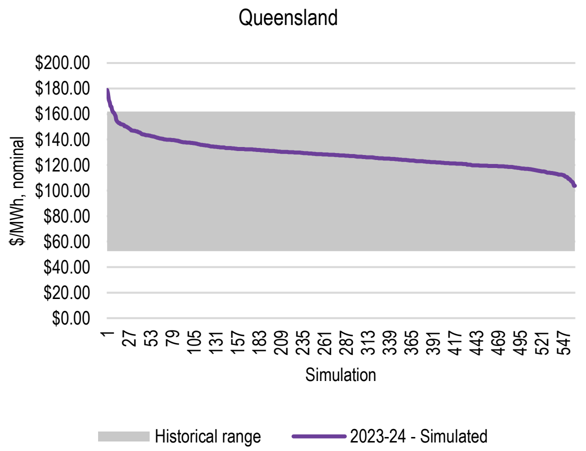
The mid right panel of Figure 5.8 compares the lower 50 per cent of hourly prices in the simulations with historical spot prices. The projected increase in uptake of rooftop PV coupled with the commissioning of the committed utility scale solar projects in Queensland by 2023-24 results in an increase in the proportion of hours in which the price is zero or negative.

The lower left panel of Figure 5.8 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 2023-24 during daylight hours.

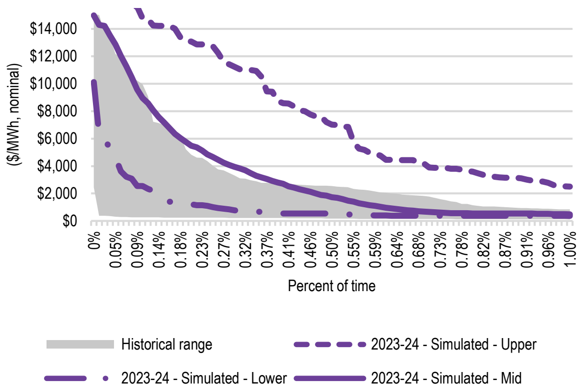
Based on these metrics, ACIL Allen is satisfied that in an aggregate sense the distribution of the 561 simulations for 2023-24 cover an adequately wide range of possible annual spot price outcomes.

**Figure 5.8** Comparison of various metrics of hourly prices from the 2023-24 simulations with historical outcomes – Queensland

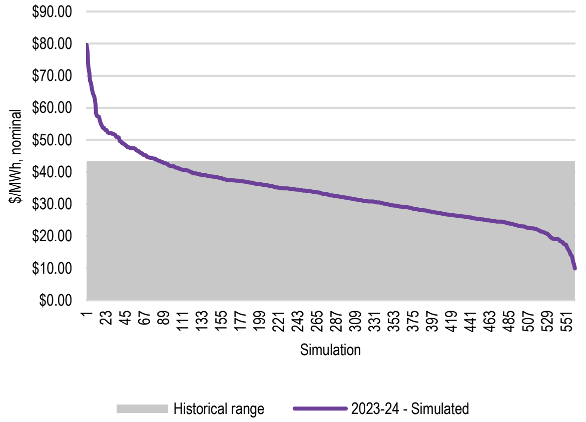
Annual TWPs



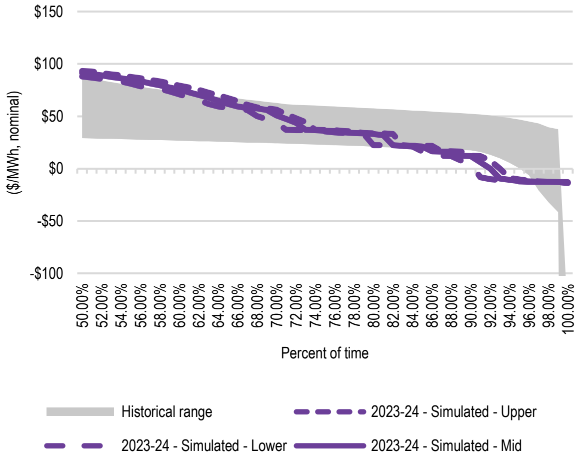

Upper one percent of hourly prices



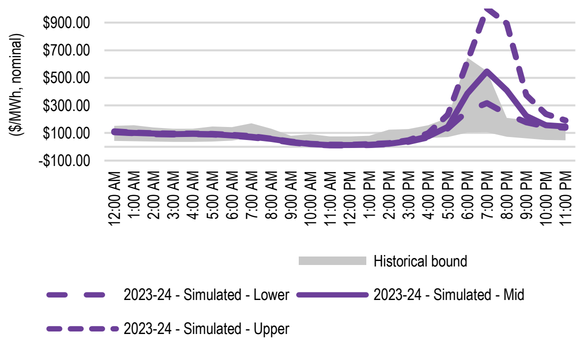

Annual average contribution to the Queensland TWP by prices above $300/MWh




Lower 50 per cent of hourly prices




Average time of day hourly prices



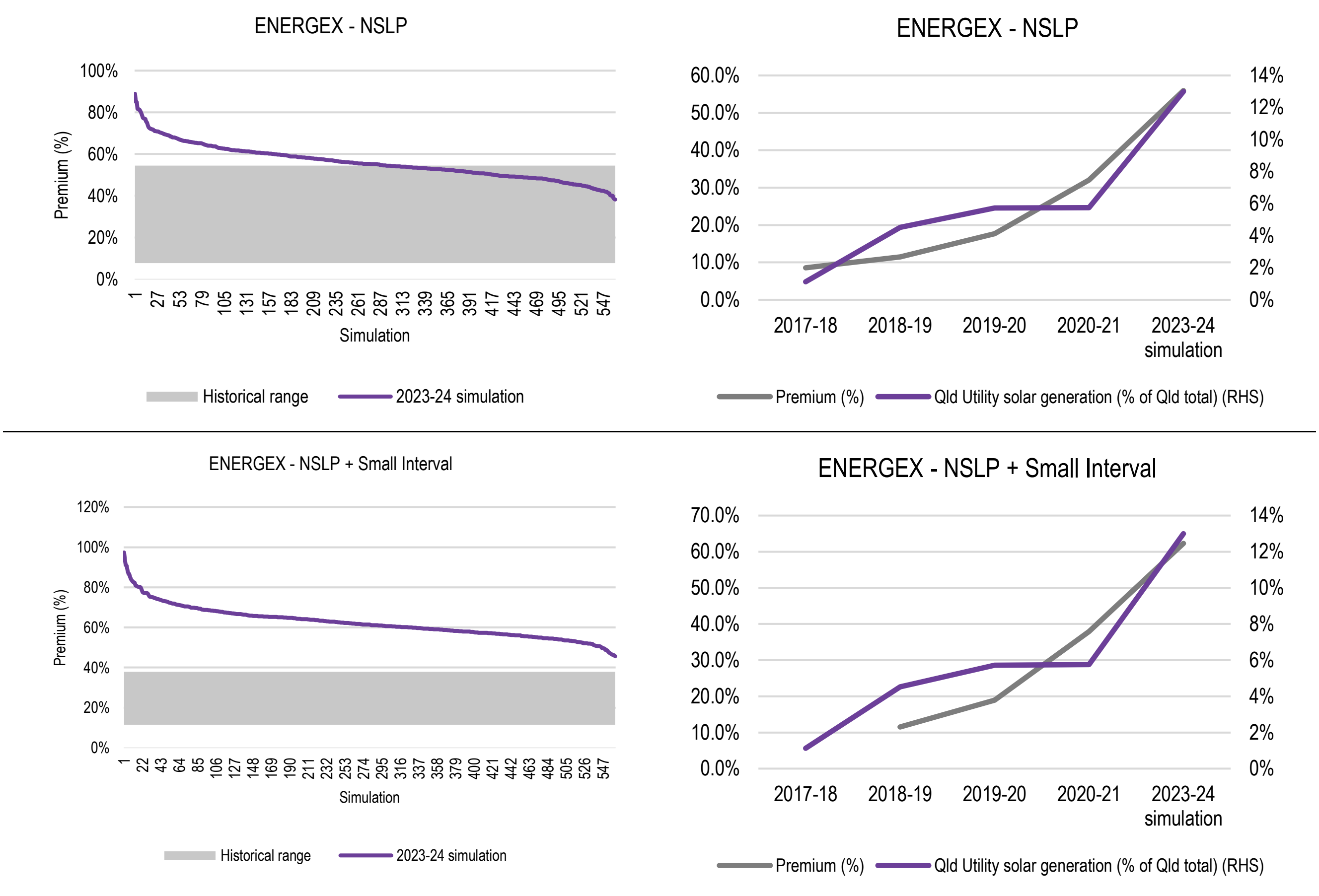

*Source: ACIL Allen analysis and AEMO data*

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

A test of the appropriateness of the simulated demand shape and its relationship with the regional demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the given demand profile with the corresponding regional TWP. Figure 5.9 shows that, for the past 10 financial years, the DWP for the Energex NSLP as a percentage premium over the Queensland TWP has varied from a low of 8 percent to a high of 54 percent in. In the 561 simulations for 2023-24 for the NSLP, this percentage varies from 38 percent to 89 percent. The modelling suggests a greater range in the premium for 2023-24 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability coupled a decline in price outcomes during daylight hours, due to the commissioning of utility scale PV, when the NSLP demand is at its lowest. Included in Figure 5.9 is a comparison showing the correlation in the growth in premium over the past few years and the increasing market share of solar output.

The comparison with actual outcomes over the past 10 years in Figure 5.9 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 561 simulations is sound.

**Figure 5.9** Simulated annual DWP for Energex NSLP and small interval meter load as percentage premium of annual TWP for 2023-24 compared with range of actual outcomes in past years, and market share of utility scale solar (%)




*Source: ACIL Allen analysis and AEMO data*

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 561 simulations cover the range of expected price outcomes for 2023-24 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 51 simulated demand and renewable energy resource traces combined with the 11 thermal power plant outage scenarios provide a sound basis for modelling the expected future range in spot market outcomes for 2023-24.

### 5.2.3 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 5.2.1.

Contract volumes adopted for the hedging strategy for 2023-24 are calculated for each settlement class for each quarter as follows:

The contract volumes are calculated for the NSLP and interval meter load for each quarter as follows:

— The base contract volume is set to equal the 50th percentile of the off-peak period hourly demands across all 51 demand sets for the quarter. This is a decrease compared with 2022-23 reflecting the changing differential between base and cap contract prices, as well as a deeper carve in the load profile due to the inclusion of the interval meter load.

— The cap contract volume is set at 100 per cent of the median of the annual peak demands across the 51 demand sets minus the base and peak contract volumes. This is an increase from the 2022-23 Determination and is due to the stronger increase in base contract prices relative to cap prices. The optimal hedging strategy allows for a small amount of exposure to the spot market.

Given the Energex small business primary load control tariff is a primary tariff, the optimal contract volumes are calculated separately, and are:

— The base contract volume is set to equal the 50th percentile of the off-peak period hourly demands across all 51 demand sets for the quarter.

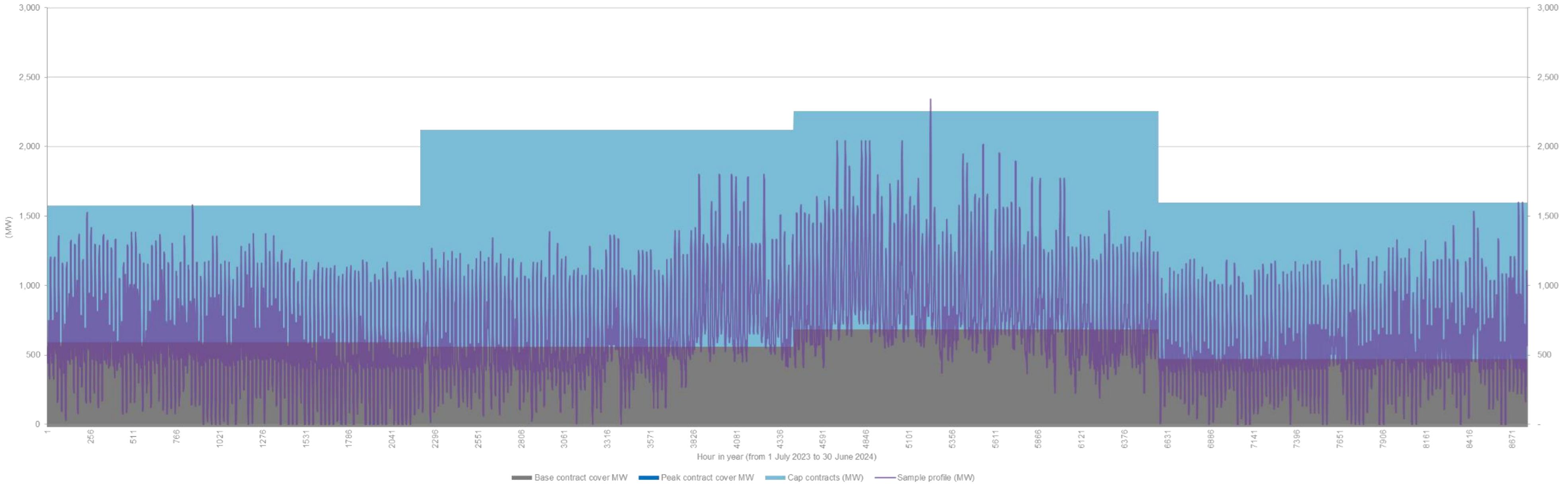
— The cap contract volume is set at 70 per cent of the median of the annual peak demands across the 51 demand sets minus the base and peak contract volumes.

The same hourly hedge volumes (in MW terms) apply to each of the 51 demand sets for a given tariff class and year, and hence to each of the 561 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 51 demand sets. Therefore, the approach we use results in a hedging strategy that does not rely on perfect foresight but relies on an expectation of the distribution of hourly demands across a range of weather-related outcomes.

Once established, these contract volumes are then fixed across all 561 simulations when calculating the wholesale energy cost. The contract volumes adopted for the Energex NSLP plus small interval meter load are shown in Figure 5.10. It can be seen there is a higher weighting (or reliance) on cap contracts compared with base contracts.

The contracting strategy places no reliance on peak contracts. This is not surprising – the carve out of demand during daylight hours (which makes up a reasonable part of the peak hours on business days), and the corresponding low spot prices during those hours makes the peak contacts generally unappealing. It is during these periods that the load will be over contracted and hence in effect retailers will be selling back to the market the extent of this over contracted position at the much lower spot prices. Further, the strategy's non-reliance on peak contracts matches well with the very small or nil volume of peak contracts traded relative to base contracts in the actual futures market.

**Figure 5.10** Contract volumes used in hedge modelling of 561 simulations for 2023-24 for Energex NSLP + small interval meter load

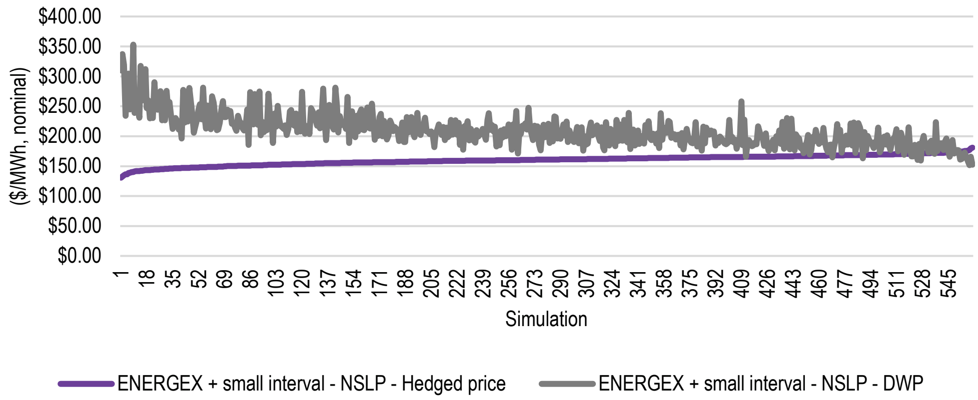



*Source: ACIL Allen analysis*

Figure 5.11 shows that, by using the above contracting strategies, the variation in the annual hedged price for the NSLP plus small interval meter load is far less than the variation if the NSLP plus small interval meter load was to be supplied without any hedging and relied solely on spot price outcomes.

It is worth noting the hedged price outcomes for the NSLP plus small interval meter load are lower than the spot price outcomes in some of the simulations. This is a result of the trade weighted average contract prices being less than the spot price simulations, and less than the current consensus view of outcomes for 2023-24.

**Figure 5.11** Annual hedged price and DWP ($/MWh, nominal) for Energex NSLP + small interval meter load for the 561 simulations – 2023-24




*Source: ACIL Allen analysis*

### 5.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the final WEC estimate is taken as the 95th percentile of the distribution containing 561 WECs (the annual hedged prices). ACIL Allen's estimate of the WEC for each tariff class for 2023-24 are shown in Table 5.2.

**Table 5.2** Estimated WEC ($/MWh, nominal) for 2023-24 at the regional reference node

| Settlement class | 2023-24 – Final Determination | 2022-23 – Final Determination | Change from 2022-23 to 2023-24 (%) |
|---|---|---|---|
| Energex - Residential and small business | $171.87 | $94.93 | 81% |
| Energex - Controlled load tariff 9000 (31) | $115.28 | $78.80 | 46% |
| Energex - Controlled load tariff 9100 (33) | $118.41 | $83.78 | 41% |
| Energex - Unmetered supply | $171.87 | $94.93 | 81% |
| Ergon Energy - CAC and ICC | $101.83 | $84.61 | 20% |
| Ergon Energy - SAC demand and street lighting | $124.20 | $84.61 | 47% |
| Energex – Small business primary load control tariff | $125.78 | $82.20 | 53% |
| Ergon – Large business primary and secondary load control tariffs | $118.41 | $83.78 | 41% |
| Energex - Residential and small business - Time varying - Night | $110.81 | | |
| Energex - Residential and small business - Time varying - Day | $42.06 | | |
| Energex - Residential and small business - Time varying - Evening Peak | $315.80 | | |

| Settlement class | 2023-24 – Final Determination | 2022-23 – Final Determination | Change from 2022-23 to 2023-24 (%) |
|---|---|---|---|

*Source: ACIL Allen analysis*

### 5.2.5 Do the changes in WEC make intuitive sense?

An increase in WEC of 41 to 81 per cent is very large and will impact the cost of living for residential consumers, as well as the input costs for businesses for which electricity represents a high proportion of production input.

Hence the estimated WECs warrant further investigation to ensure the estimated changes align with what is observed in the market. The charts below plot the changes in WECs and trade weighted contract prices from this Final Determination together with previous final determinations.

The top chart plots the annual change, and the lower chart plots the cumulative change since 2013-14 (using 2013-14 as the base observation). Key features of the charts are:

— Overall, the year-on-year trend in estimated WECs follows the trend in contract prices.

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

— However, the trend in WEC is also influenced by the change in cap prices. The charts show changes in percentage terms, and given that cap contract prices are lower than base contract prices in dollar terms, it is not surprising that the percentage changes in cap contact prices are larger than changes in the base contract prices and WECs (since they are starting from a lower base).

— The trend in cap price movements displays the largest degree of variability of the contract products, with very large increase occurring in 2017-18, 2022-23 and 2023-24.

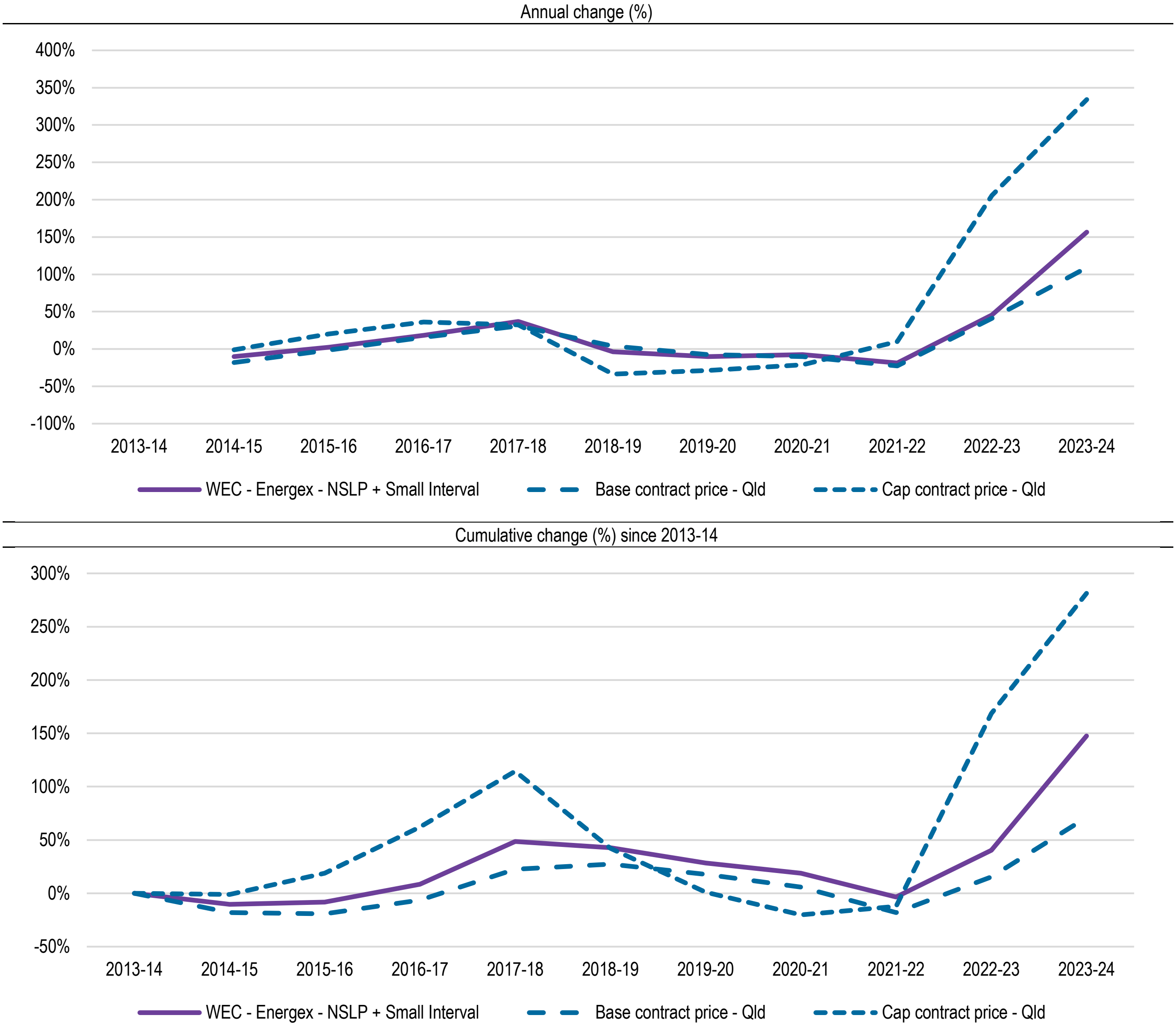
— The trend in WECs aligns very closely to the trend in base contract prices. This is not surprising given the strong reliance on base contracts in the hedging strategy.

— The large percentage increases in WEC in 2017-19, 2022-23 and 2023-24 align with the corresponding strong increases in contract prices.

— There has been no occasion in which the movement in the WEC is at odds with the movement in observable trade weighted average contract prices.

On this basis, ACIL Allen is satisfied that the methodology is appropriately estimating the WECs for 2023-24, and that the estimated WECs reflect the consensus view of market conditions for the given determination year at the time the determination was made.

**Figure 5.12** Change in WEC and trade weighted contract prices (%) – 2013-14 to 2023-24




Note: Cumulative change uses 2013-14 as the base observation.
*Source: ACIL Allen analysis*

## 5.3 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[15]) are required to comply and surrender certificates for both LRET and SRES.

Energy costs associated with the LRET and the SRES have been estimated using price information from brokers TraditionAsia, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen.

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2023 and 2024 calendar years, with the costs averaged to estimate the 2023-24 financial year costs.

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

— historical Large-scale Generation Certificate (LGC) market forward prices for 2023 and 2024 from brokers TraditionAsia
— estimated Renewable Power Percentages (RPP) values for 2023 and 2024 of 18.96 per cent[16]
— binding Small-scale Technology Percentage (STP) values for 2023 of 16.29 per cent, as published by CER
— estimated STP value for 2024 of 17.99 per cent[17]
— CER clearing house price[18] for 2023 and 2024 for Small-scale Technology Certificates (STCs) of $40/MWh.

### 5.3.1 LRET

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

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

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

ACIL Allen has estimated the average LGC price using LGC forward prices provided by broker TraditionAsia up to 10 May 2023.

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[15] 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.

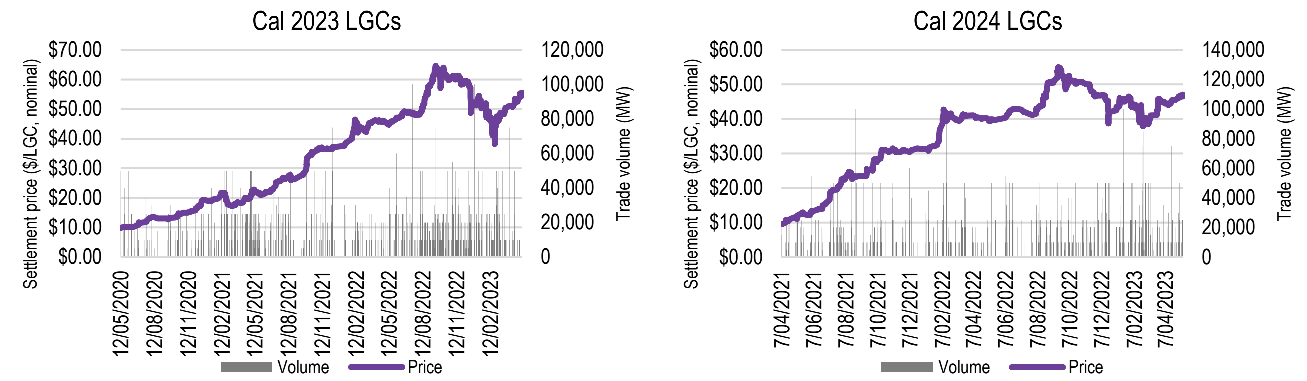
[16] The RPP values for 2023 and 2024 are based on the CER's published RPP for 2023 and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2023 and 2024.

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

[18] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

The LGC price used in assessing the cost of the scheme for 2023-24 is found by taking the trade-weighted average of the forward prices for the 2023 and 2024 calendar years, respectively, since the contracts commenced trading. This is typically about 2.5 years prior to the commencement of the compliance year (see Figure 5.13). The average LGC prices calculated from the TraditionAsia data are $40.56/MWh for 2023 and $37.85/MWh for 2024**.**

**Figure 5.13** LGC prices for 2023 and 2024 for 2023-24 ($/LGC, nominal)




*Source: ACIL Allen analysis of TraditionAsia data*

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

Key elements of the 2023 and 2024 RPP estimation are shown in Table 5.3.

**Table 5.3** 2023 and 2024 RPP values

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

*Source: ACIL Allen analysis of CER and AEMO data*

ACIL Allen calculates the cost of complying with the LRET in 2023 and 2024 by multiplying the RPP values for 2023 and 2024 by the trade volume weighted average LGC prices for 2023 and 2024, respectively. The cost of complying with the LRET in 2023-24 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $7.44/MWh in 2023-24 as shown in Table 5.4**.**

**Table 5.4** Estimated cost of LRET – 2023-24

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

| | 2023 | 2024 | Cost of LRET 2023-24 |
|---|---|---|---|
| **Cost of LRET ($/MWh, nominal)** | $7.69 | $7.18 | $7.44 |

*Source: ACIL Allen analysis of CER and TraditionAsia data*

### 5.3.2 SRES

The cost of the SRES is calculated by applying the estimated STP value to the STC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2023-24.

ACIL Allen estimates the cost of complying with SRES to be $6.86/MWh in 2023-24 as set out in Table 5.5.

**Table 5.5** Estimated cost of SRES – 2023-24

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

*Source: ACIL Allen analysis of CER data*

### 5.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2023-24 as set out in Table 5.6.

Since the 2022-23 estimate, the cost of LRET has increased by around 49 per cent, driven by higher LGC prices in 2023-24, and the cost of SRES has decreased by 37 per cent, driven by the shortening of the SRES deeming period.

**Table 5.6** Total renewable energy policy costs ($/MWh, nominal) – 2023-24

| | 2022-23 | 2023-24 |
|---|---|---|
| LRET | $5.00 | $7.44 |
| SRES | $10.90 | $6.86 |
| **Total** | **$15.90** | **$14.30** |

*Source: ACIL Allen analysis*

## 5.4 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
- spot and hedging prudential costs
- the Reliability and Emergency Reserve Trader (RERT).

### 5.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA)[19], DER and IT system upgrades for 5MS.

The estimate for the NEM management fees is taken from AEMO's latest budget and fees report for the given financial year. At this stage AEMO has released its draft budget report for 2023-24, which we have used.

Based on the fees provided by AEMO's *Draft FY24 Budget and Fees,* our estimate of the fees for 2022-23 are $0.95/MWh. The decrease in fees largely relates to the decrease in NEM core fees.

**Table 5.7** NEM management fees ($/MWh, nominal) – 2023-24

| Cost category | 2022-23 | 2023-24 |
|---|---|---|
| NEM fees (admin, registration, etc.) | $0.77 | $0.57 |
| FRC - electricity | $0.077 | $0.0802 |
| ECA - electricity | $0.037 | $0.0404 |
| DER fee | $0.025 | $0.02370 |
| IT upgrade and 5MS/GS compliance | $0.219 | $0.2438 |
| **Total NEM management fees** | **$1.13** | **$0.95** |

*Source: ACIL Allen analysis of AEMO reports*

### 5.4.2 Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs in each region over the preceding 52 weeks of currently available NEM ancillary services data as a basis for 2023-24, the estimates cost of ancillary services is shown in Table 5.8.

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

**Table 5.8** Ancillary services ($/MWh, nominal) – 2023-24

| Region | 2022-23 | 2023-24 |
|---|---|---|
| Queensland | $1.42 | $0.47 |

*Source: ACIL Allen analysis of AEMO data*

### 5.4.3 Prudential costs

Prudential costs have been calculated for each distribution area. The prudential costs for the NSLP and interval meter load are then used as a proxy for prudential costs for the controlled load profiles in the relevant jurisdiction.

[19] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2022-23* of the assumed number of connection points for small customers used in the estimate, therefore ACIL Allen has used DNSP customer numbers to estimate the cost of ECA requirements in $/MWh terms.

**AEMO prudential costs**

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

— bank guarantees
— reallocation certificates
— prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = OSL + PML

Where for the Summer (December to March), Winter (May to August) and Shoulder (other months):

OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x (GST + 1) x 35 days

PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x (GST + 1) x 7 days

Taking a 1 MWh average daily load and assuming the inputs in Table 5.9 for each season for the Energex NSLP and small interval meter load gives an estimated MCL of $25,914.

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 $25,914/42 = $617.01/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 $617.01 gives $1.77/MWh.

The components of the AEMO prudential costs for Ergon NSLP and large interval meter load are shown in Table 5.10.

**Table 5.9** AEMO prudential costs for Energex NSLP and small interval meter load – 2023-24

| Factor | Summer | Winter | Shoulder |
|---|---|---|---|
| Load Weighted Expected Price ($/MWh, nominal) | $170.87 | $146.90 | $144.84 |
| Participant Risk Adjustment Factor | 1.6627 | 1.8350 | 1.9671 |
| OS Volatility factor | 1.51 | 1.55 | 1.41 |
| PM Volatility factor | 2.98 | 2.19 | 1.88 |
| OSL | $21,298 | $21,791 | $21,693 |
| PML | $4,260 | $4,358 | $4,339 |
| MCL | $25,557 | $26,150 | $26,032 |
| Average MCL | | $25,914 | |
| **AEMO prudential cost ($/MWh, nominal)** | | **$1.77** | |

*Source: ACIL Allen analysis of AEMO data*

**Table 5.10** AEMO prudential costs for Ergon NSLP and large interval meter load – 2023-24

| Factor | Summer | Winter | Shoulder |
|---|---|---|---|
| Load Weighted Expected Price ($/MWh, nominal) | $170.87 | $146.90 | $144.84 |
| Participant Risk Adjustment Factor | 1.0375 | 1.0306 | 1.0164 |
| OS Volatility factor | 1.51 | 1.55 | 1.41 |
| PM Volatility factor | 2.98 | 2.19 | 1.88 |
| OSL | $10,497 | $9,171 | $8,057 |
| PML | $2,099 | $1,834 | $1,611 |
| MCL | $12,596 | $11,005 | $9,669 |
| Average MCL | | $11,090 | |
| **AEMO prudential cost ($/MWh, nominal)** | | **$0.76** | |

*Source: ACIL Allen analysis of AEMO data*

### Hedge prudential costs

ACIL Allen has relied on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The assumed money market rate is 3.85 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

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

- the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 18 percent on average for a base contract, and 20 percent for a cap contract
- the intra monthly spread charge currently set at $12,300 for a base contract of 1 MW for a quarter, and $5,900 for a cap contract
- the spot isolation rate currently set at $1,500 for a base contract, and $600 for a cap contract.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter (rounded up) as shown for Queensland in Table 5.11. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 8.86 per cent but adjusted for an assumed 3.85 per cent return on cash lodged with the clearing (giving a net funding cost of 5.01 percent) results in the prudential cost per MWh for each contract type.

Average initial margins for Queensland using the average contract prices and initial margin parameters results in a prudential cost per MWh for each contract type as shown in the right column of Table 5.11.

**Table 5.11** Hedge Prudential funding costs by contract type – Queensland 2023-24

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

*Source: ACIL Allen analysis of ASX Energy and RBA data*

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 to give a proportional factor. The product of the prudential cost per MWh for each contract type and the proportion of each contract in the hedge model profile provides the total hedge prudential cost per MWh associated with each contract type. These are then summed to establish the total hedge prudential costs for the Energex and Ergon as shown in Table 5.12 and Table 5.13 respectively.

**Table 5.12** Hedge Prudential funding costs for ENERGEX NSLP and small interval meter load – 2023-24

| Contract Type | Prudential cost per MWh | Proportion of contract hedged against average annual energy | Hedge prudential cost per MWh |
|---|---|---|---|
| Base | $1.21 | 0.8967 | $1.09 |
| Cap | $0.46 | 2.0663 | $0.95 |
| **Total cost** | | **$2.03** | |

*Source: ACIL Allen analysis*

**Table 5.13** Hedge Prudential funding costs for ERGON NSLP and large interval meter load – 2023-24

| Contract Type | $1.19 | 0.9379 | $1.12 |
|---|---|---|---|
| Base | $1.21 | 0.9379 | $1.14 |
| Cap | $0.46 | 0.7607 | $0.35 |
| **Total cost** | | **$1.49** | |

*Source: ACIL Allen analysis*

### Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2023-24 as set out in Table 5.14. Prudential costs for 2023-24 are higher than 2022-23 for the Energex due to higher hedge prices and higher expected price volatility across 2023-24, as well as the inclusion of the peakier small interval meter load. Prudential costs do not increase as much for the Ergon profile due to the inclusion of the less peakier large interval meter load.

**Table 5.14** Total prudential costs ($/MWh, nominal) – 2023-24

| Jurisdiction | 2022-23 | 2023-24 |
|---|---|---|
| Energex NSLP and small interval meter load | $2.55 | $3.81 |
| Ergon NSLP and large interval meter load | $2.10 | $2.24 |

*Source: ACIL Allen analysis*

## 5.4.4 Reliability and Emergency Reserve Trader (RERT)

As with the ancillary services, we take the RERT costs as published by AEMO for the 12-month period prior to the Final Determination.

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

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

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

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

## 5.4.5 June 2022 NEM events

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

The total cost to date for Queensland is $45,000,550, which when recovered across the customer load equates to $0.90/MWh.

**Table 5.15** Cost of June 2022 NEM events - Queensland

| Item | Cost |
|---|---|
| RERT payments (for activated demand response under RERT contracts) | $3,800,000 |
| Directions compensation (directed participants for energy, ancillary services or other compensable services) | $9,070,000 |
| Suspension pricing compensation (for eligible costs not recovered by spot prices when set/affected by market suspension pricing schedule prices) | $25,560,000 |
| Administered pricing compensation (for eligible costs when spot market prices were set/affected by the administered price cap) | $6,570,550 |
| Total | $45,000,550 |

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

### 5.4.6 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 5.16 and Table 5.17, for the 2023-24 Final Determination and is compared with the costs for 2022-23.

**Table 5.16** Total of other costs ($/MWh, nominal) – Energex – 2023-24

| Cost category | 2022-23 | 2023-24 |
|---|---|---|
| NEM management fees | $1.13 | $0.95 |
| Ancillary services | $1.42 | $0.47 |
| Hedge and spot prudential costs | $2.55 | $3.81 |
| Reserve and Emergency Reserve Trader | $1.01 | $0.04 |
| June 2022 NEM events | | $0.90 |
| **Total** | **$6.11** | **$6.17** |

*Source: ACIL Allen analysis*

**Table 5.17** Total of other costs ($/MWh, nominal) – Ergon – 2023-24

| Cost category | 2022-23 | 2023-24 |
|---|---|---|
| NEM management fees | $1.13 | $0.95 |
| Ancillary services | $1.42 | $0.47 |
| Hedge and spot prudential costs | $2.10 | $2.24 |
| Reserve and Emergency Reserve Trader | $1.01 | $0.04 |
| June 2022 NEM events | | $0.90 |
| **Total** | **$5.66** | **$4.61** |

*Source: ACIL Allen analysis*

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

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2023-24 is shown in Table 5.18**.**

**Table 5.18** Estimated transmission and distribution losses

| | 2022-23 | | | 2023-24 | | |
|---|---|---|---|---|---|---|
| | Distribution loss factor (DLF) | Transmission marginal loss factor (MLF) | Total loss factors (MLFxDLF) | Distribution loss factor (DLF) | Transmission marginal loss factor (MLF) | Total loss factors (MLFxDLF) |
| Energex – Residential and small business | 1.061 | 1.007 | 1.069 | 1.059 | 1.009 | 1.068 |
| Energex – Controlled load tariff 9000 (31) | 1.061 | 1.007 | 1.069 | 1.059 | 1.01 | 1.068 |
| Energex – Controlled load tariff 9100 (33) | 1.061 | 1.007 | 1.069 | 1.059 | 1.009 | 1.068 |
| Energex - unmetered supply | 1.061 | 1.007 | 1.069 | 1.059 | 1.009 | 1.068 |
| Ergon Energy - CAC and ICC | 1.036 | 0.985 | 1.020 | 1.033 | 0.971 | 1.003 |
| Ergon Energy - SAC demand and street lighting | 1.083 | 0.985 | 1.067 | 1.094 | 0.971 | 1.062 |
| Energex – Small business primary load control tariff | 1.061 | 1.007 | 1.069 | 1.059 | 1.009 | 1.068 |
| Ergon – Large business primary and secondary load control tariffs | 1.083 | 0.985 | 1.067 | 1.094 | 0.971 | 1.062 |

*Source: ACIL Allen analysis of AEMO data*

As described by AEMO[20], 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)*

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

## 5.6 Summary of estimated energy costs

Drawing together the analyses and estimates from the previous sections of this report, ACIL Allen's estimates of the 2023-24 total energy costs (TEC) for the Final Determination for each of the profiles are presented in Table 5.19.

**Table 5.19** Estimated TEC for 2023-24 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 ($/MWh) | Change from 2022-23 Final Determination ($/MWh) | Change from 2022-23 Final Determination (%) |
|---|---|---|---|---|---|---|---|---|
| Energex – Residential and small business | $171.87 | $14.30 | $6.17 | 1.068 | $13.08 | **$205.42** | $80.41 | 64.32% |
| Energex – Controlled load tariff 9000 (31) | $115.28 | $14.30 | $6.17 | 1.068 | $9.23 | **$144.98** | $37.21 | 34.53% |
| Energex – Controlled load tariff 9100 (33) | $118.41 | $14.30 | $6.17 | 1.068 | $9.44 | **$148.32** | $35.23 | 31.15% |
| Energex – unmetered supply | $171.87 | $14.30 | $6.17 | 1.068 | $13.08 | **$205.42** | $80.41 | 64.32% |
| Ergon Energy – CAC and ICC | $101.83 | $14.30 | $4.61 | 1.003 | $0.36 | **$121.10** | $12.81 | 11.83% |
| Ergon Energy - SAC demand and street lighting | $124.20 | $14.30 | $4.61 | 1.062 | $8.87 | **$151.98** | $38.70 | 34.16% |
| Energex – Small business primary load control tariff | $125.78 | $14.30 | $6.17 | 1.068 | $9.95 | **$156.20** | $44.80 | 40.22% |
| Ergon – Large business primary and secondary load control tariffs | $118.41 | $14.30 | $4.61 | 1.062 | $8.51 | **$145.83** | $33.43 | 29.74% |
| Energex - Residential and small business - Time varying - Night | $110.81 | $14.30 | $6.17 | 1.068 | $8.93 | **$140.21** | | |
| Energex - Residential and small business - Time varying - Day | $42.06 | $14.30 | $6.17 | 1.068 | $4.25 | **$66.78** | | |
| Energex - Residential and small business - Time varying - Evening Peak | $315.80 | $14.30 | $6.17 | 1.068 | $22.87 | **$359.14** | | |

*Source: ACIL Allen analysis*

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