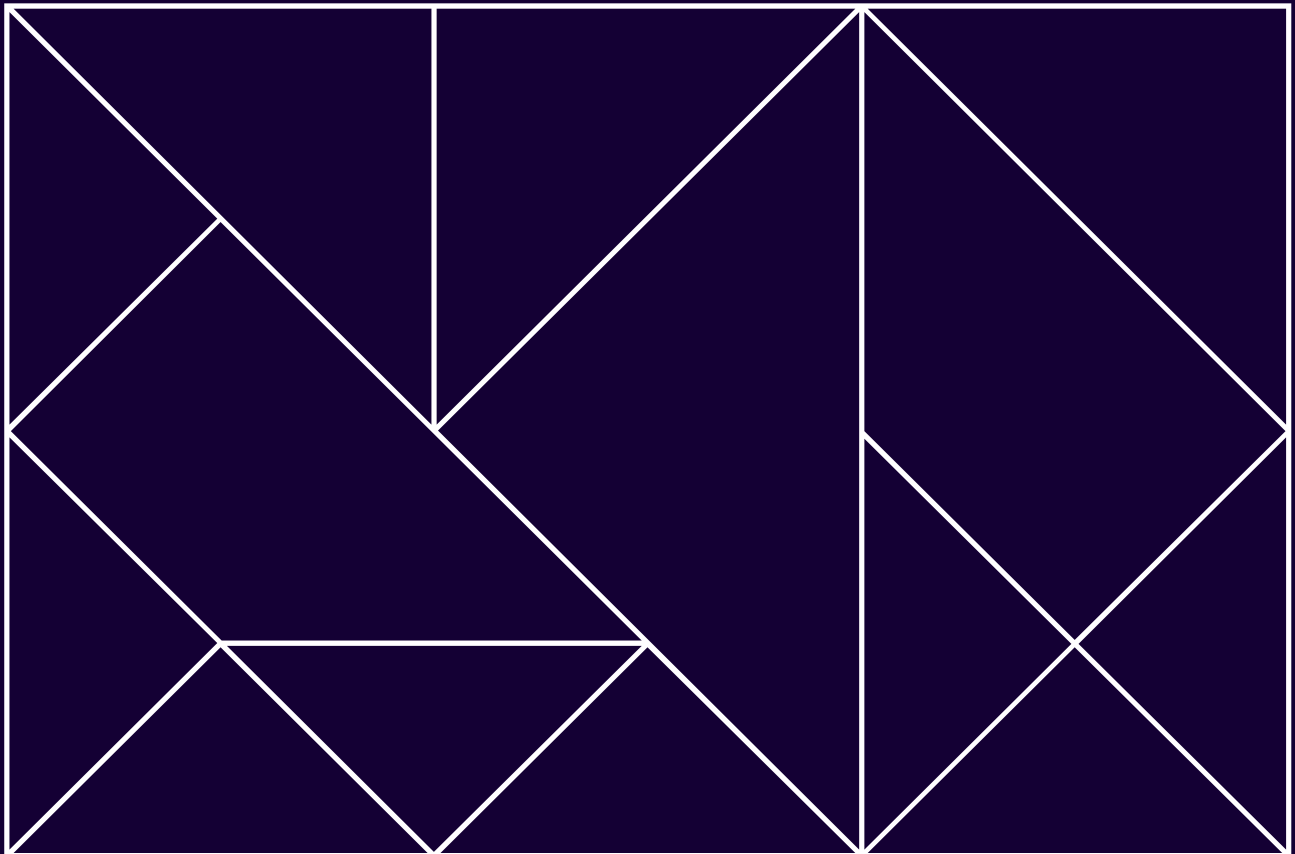


23 May 2024

Report to Queensland Competition Authority

Estimated energy costs

For use by the Queensland Competition Authority in its Final Determination of 2024-25 retail electricity tariffs



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

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Suggested citation for this report

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Contents

1	Introduction	5
2	Overview of approach	6
2.1	Introduction	6
2.2	Components of the total energy cost estimates	6
2.3	Methodology	7
3	Responses to submissions to the Draft Determination	34
4	Estimation of energy costs	35
4.1	Introduction	35
4.2	Estimation of the Wholesale Energy Cost	40
4.3	Estimation of renewable energy policy costs	52
4.4	Estimation of other energy costs	54
4.5	Estimation of energy losses	60
4.6	Summary of estimated energy costs	62
	Figures	
Figure 2.1	Components of TEC	7
Figure 2.2	Illustrative example of hedging strategy, prices and costs	9
Figure 2.3	Average time of day demand (MW, relative)	12
Figure 2.4	Energex NSLP (MW) – July 2021 to January 2024	16
Figure 2.5	Energex NSLP (MW) – July 2021 to January 2024	17
Figure 2.6	Average time of day profile (MW) – Energex NSLP	17
Figure 2.7	Estimating the WEC – market-based approach	23
Figure 2.8	Daily settlement prices and trade volume weighted prices (\$/MWh) for Q1 base contracts in Queensland	25
Figure 2.9	Illustrative comparison of WEC estimation accuracy given market environment	26
Figure 2.10	Steps to estimate the cost of LRET	31
Figure 2.11	Steps to estimate the cost of SRES	32
Figure 4.1	Actual average time of day wholesale electricity spot price (\$/MWh, nominal) and load profiles (MW, relative) – Queensland – 2018-19 to 2022-23	38
Figure 4.2	Actual annual average demand weighted price (\$/MWh, nominal) by profile and Queensland time weighted average price (\$/MWh, nominal) – 2009-10 to 2023-24	39
Figure 4.3	Queensland Base, Peak, and Cap trade weighted average contract prices (\$/MWh, nominal) – 2013-14 to 2024-25	40
Figure 4.4	Time series of trade volume and price – ASX Energy base futures - Queensland	42
Figure 4.5	Time series of trade volume and price – ASX Energy \$300 cap futures - Queensland	43
Figure 4.6	Comparison of upper one per cent of hourly loads of 2024-25 simulated hourly demand sets with historical outcomes – Queensland	44
Figure 4.7	Comparison of upper one per cent of hourly loads and load factors of 2024-25 simulated hourly demand sets with historical outcomes – Energex NSLP and small interval meter load	45
Figure 4.8	Comparison of various metrics of hourly prices from the 2024-25 simulations with historical outcomes – Queensland	46

Contents

Figure 4.9	Simulated annual DWP for Energex NSLP and small interval meter load as percentage premium of annual TWP for 2024-25 compared with range of actual outcomes in past years, and market share of utility scale solar (%)	47
Figure 4.10	Contract volumes used in hedge modelling of 583 simulations for 2024-25 for Energex NSLP + small interval meter import load	49
Figure 4.11	Annual hedged price and DWP (\$/MWh, nominal) for Energex NSLP + small interval meter load for the 583 simulations – 2024-25	50
Figure 4.12	Change in WEC and trade weighted contract prices (%) – 2013-14 to 2024-25	51
Figure 4.13	LGC prices for 2024 and 2025 for 2024-25 (\$/LGC, nominal)	53
Tables		
Table 2.1	Sources of load data	10
Table 2.2	Load profiles adopted for estimation of WEC by customer settlement class	12
Table 2.3	Overview of key modelling assumptions relevant for 2024-25	19
Table 2.4	Near-term addition to supply	21
Table 3.1	Review of issues raised in submissions in response to the Draft Determination	34
Table 4.1	Estimated contract prices (\$/MWh, nominal) - Queensland	40
Table 4.2	Estimated WEC (\$/MWh, nominal) for 2024-25 at the regional reference node	50
Table 4.3	2024 and 2025 RPP values	53
Table 4.4	Estimated cost of LRET – 2024-25	53
Table 4.5	Estimated cost of SRES – 2024-25	54
Table 4.6	Total renewable energy policy costs (\$/MWh, nominal) – 2024-25	54
Table 4.7	NEM management fees (\$, nominal) – 2024-25	55
Table 4.8	Ancillary services (\$/MWh, nominal) – 2024-25	55
Table 4.9	AEMO prudential costs for Energex NSLP and small interval meter load – 2024-25	57
Table 4.10	AEMO prudential costs for Ergon NSLP and large interval meter load – 2024-25	57
Table 4.11	Hedge Prudential funding costs by contract type – Queensland 2024-25	58
Table 4.12	Hedge Prudential funding costs for ENERGEX NSLP and small interval meter load – 2024-25	58
Table 4.13	Hedge Prudential funding costs for ERGON NSLP and large interval meter load – 2024-25	59
Table 4.14	Total prudential costs (\$/MWh, nominal) – 2024-25	59
Table 4.15	Total of other costs (\$/MWh, nominal) – Energex – 2024-25	60
Table 4.16	Total of other costs (\$/MWh, nominal) – Ergon – 2024-25	60
Table 4.17	Estimated transmission and distribution losses	61
Table 4.18	Estimated TEC for 2024-25 Final Determination	62



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 2024-25 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 2024-25.

ACIL Allen is required to provide cost estimates for:

- the net system load profiles (NSLPs) and interval 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 responds to submissions on the QCA's *Regulated retail electricity prices in regional Queensland for 2024–25: Draft determination* (May 2024) that refer to the methodology used to estimate energy costs in regulated retail electricity prices
- Chapter 4 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 2024 to 30 June 2025.

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 any outstanding 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 that were not finalised at the time of the 2023-24 Final Determination.
- 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 2023-24 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:

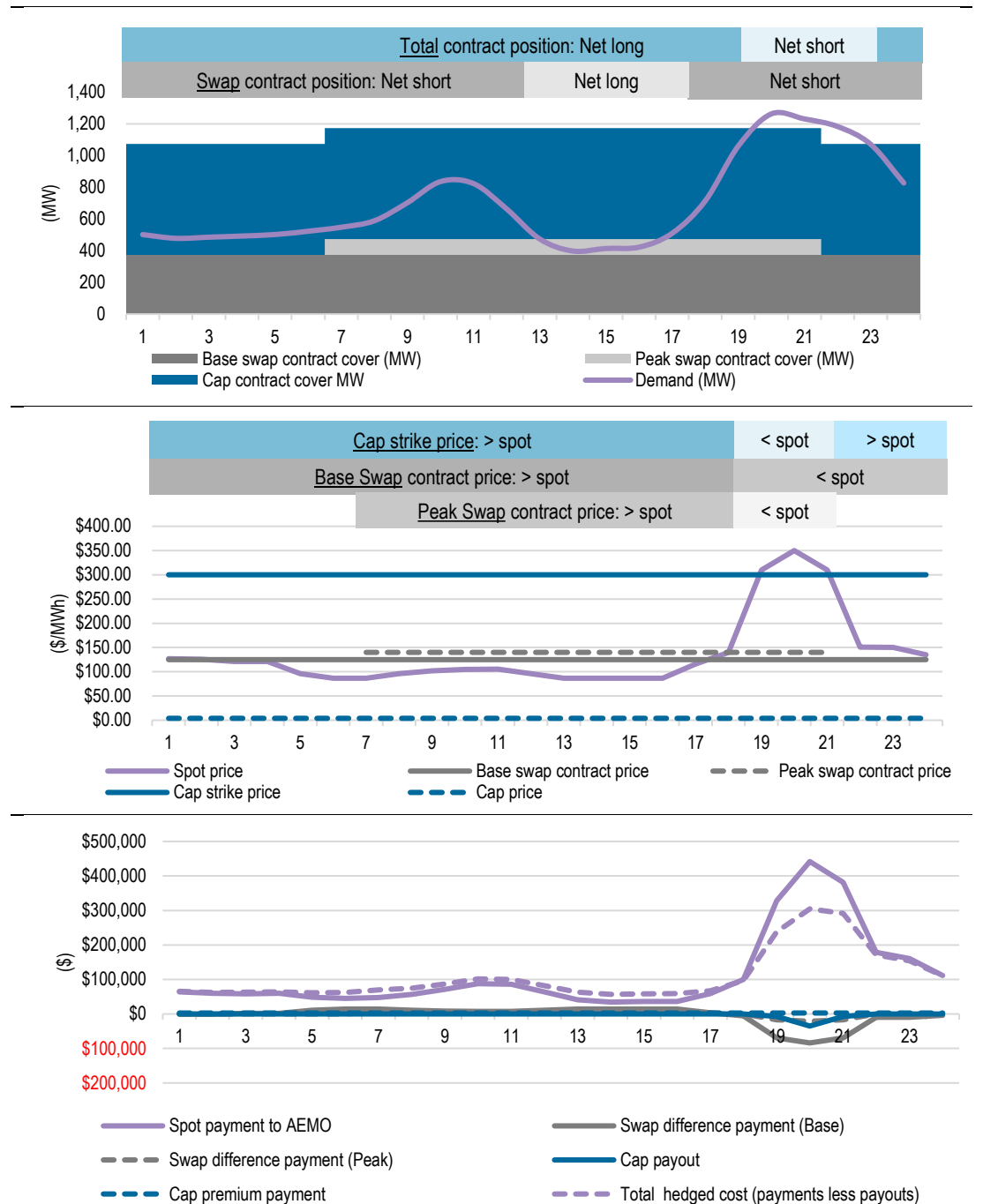
- Pays AEMO the spot price multiplied by the demand.
- Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract during the periods classified as peak. If the spot price is greater than the contract strike price then 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 set¹.

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 interval meter. 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 meters were in the minority. However, ACIL Allen estimates the penetration of interval meters in Queensland in 2022 increased to about 30 per cent, and to about 40 per cent in 2023.

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 interval meters by 2030, it is likely customers on interval meters will be the majority in the next one to two years.

In this determination, as per the 2023-24 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:

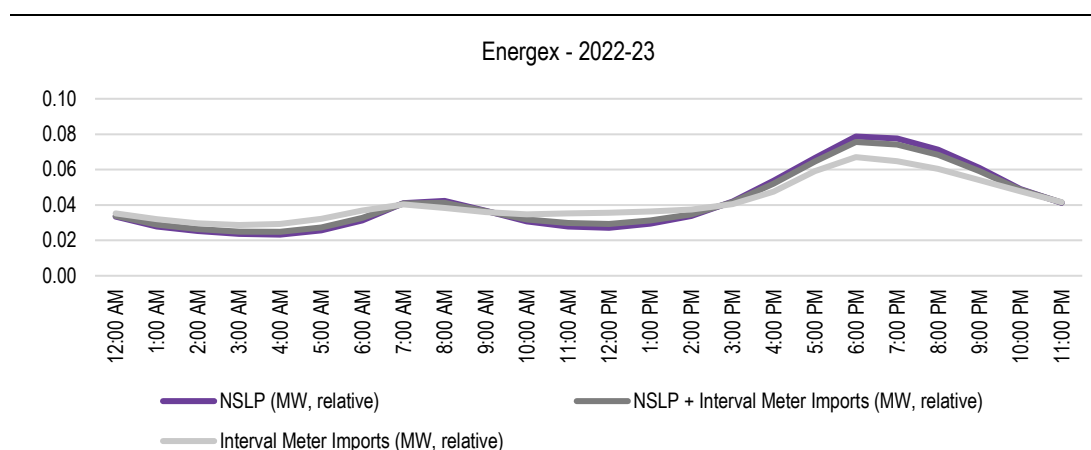
- Data transparency: At this stage AEMO does not make interval meter load profile data publicly available on its website. This means, until AEMO publish this data, that the QCA will need to proactively request the data in time for each determination, and that the data cannot be readily accessed by stakeholders for verification.
- Data validity: The purpose of the determination is to estimate the WEC from a retailer's perspective. AEMO constructs the NSLP including the 'carve out' of NSLP due to rooftop PV exported to the grid since the PV export carve out is unable to be separated from imports in the NSLP. However, for customers on interval meters, it is possible to separate out the PV export carve out, and hence 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 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 imported from the grid and solar exports

injected to the grid. This means that the aggregate demand profile (NSLP plus interval meter imports) is not completely exclusive of the PV export carve out.

- 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.

Although the interval meter data used for the 2023-24 determination included the carve out of rooftop PV exports, for the 2024-25 determination we have been able to exclude the PV export carve out by using more recent post-5MS interval meter load data supplied by AEMO. 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. Although there may be a higher penetration of rooftop PV installations in the interval meter load profile (given new installations are coupled with an interval meter), the exclusion of the PV export carve out from the interval meter load data results in the profile being slightly flatter than the NSLP (which includes the PV export carve out).

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

It is worth noting that the wholesale spot price modelling of the NEM continues to include the PV export carve out in the regional demand profiles (that is, the demand to be satisfied by scheduled and semi-scheduled generation), since this what occurs in the NEM.

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

Customer settlement class	Load profile used in WEC estimation
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 (including PV exports which are deducted from the regional demand profiles for the spot price modelling). A stochastic demand and renewable energy resource model is used to develop 53 weather influenced annual simulations of hourly demand and renewable energy resource traces. The traces are developed in a way 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 583 (i.e. 53 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 583 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs, and difference 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 number² 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 two³ 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 53 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.

² When testing the different strategies, we do not run the full set of 583 simulations as this is time prohibitive. However, we run the full set of 583 simulations once the strategy has been chosen.

³ Normally we use two to three years of data, however for this determination, we have used data covering 1 October 2021 to 30 June 2023 as this allows for the inclusion of interval meter load data from which we are able to exclude the PV export carve out.

- The approach takes the past two years of actual demand data, as well as the past 53 years of weather data and uses a matching algorithm to produce 53 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 53 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 53 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 53 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 two 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 53 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 53 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.

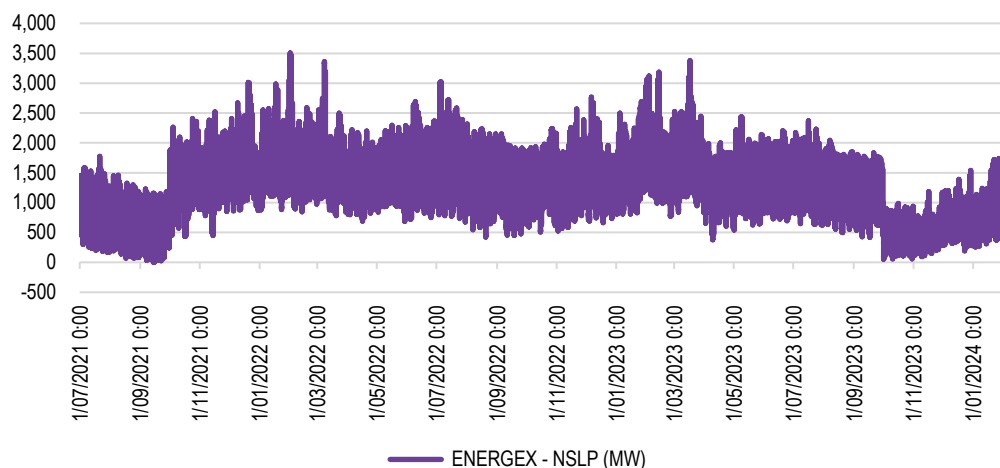
Adjustment to the Energex NSLP demand data used in the analysis

An important input to estimate the WEC 2024-25 is the load trace for small customers. The shape of the load trace and its variability, together with spot price levels, shape and volatility, influences how a retailer manages risk for this segment of the market.

Therefore, an appropriate representation of the load trace of small customers to be served by retailers in 2024-25 is required to estimate the WEC as accurately as possible. The more accurate the load trace representation for 2024-25, the more accurate the WEC estimate.

Typically, the methodology uses the past two to three years of actual NSLP load trace data to generate multiple representations of the load trace for the given determination year. Adopting this usual approach would mean using actual NSLP data spanning 1 July 2021 to 30 June 2023.

However, as shown in Figure 2.4 we observe that between 1 October 2021 and 30 September 2023 there was a step change in the NSLP load trace for Energex.

Figure 2.4 Energex NSLP (MW) – July 2021 to January 2024

Source: ACIL Allen analysis of AEMO data

The cause for this step change was not due to a sudden change in consumer behaviour or consumption patterns. The cause was AEMO making an adjustment to manage an issue relating to negative demand values coinciding with the commencement of 5MS. AEMO's adjustment resulted in an "artificial uplift" to the Energex (and South Australia) NSLP traces during this period.

This artificial uplift would have impacted how AEMO settled the NSLP with retailers during the period 1 October 2021 to 30 September 2023. However, we observe, and AEMO notes, that this artificial uplift was temporary and ceased from 1 October 2023.

This means the artificial uplift will not impact retailers in 2024-25.

Therefore, we identify three options for developing a set of representative load traces for 2024-25:

1. Take the usual approach and use the actual NSLP data spanning 1 July 2021 to 30 June 2023. This would mean that the simulated load traces for 2024-25 will include the temporary artificial uplift. Plainly this is inaccurate since the artificial uplift ceased from 1 October 2023 and will not be present in 2024-25.
2. Use older NSLP data prior to the temporary artificial uplift to represent the NSLP load trace in 2024-25. This would mean using data from 1 July 2019 to 30 June 2021. This data is between 3 to 5 years old and runs the risk of not representing the trace for 2024-25 given the movement of small customers away from the NSLP due to the ramp up in the rollout of interval meters. It also means that the spot price modelling will be based on system load trace data that is also 3 to 5 years old (recalling that to maintain internal consistency between the spot price modelling and hedge model is critical to use coincident NSLP and system demand traces from the same period).
3. Use the latest available NSLP data as per option 1, but remove the artificial uplift given it will not be present in 2024-25. This has the advantage of using the latest available data which will also allow for the pairing up with the latest available interval meter load trace data, and also means the spot price modelling is based on the latest system demand traces.

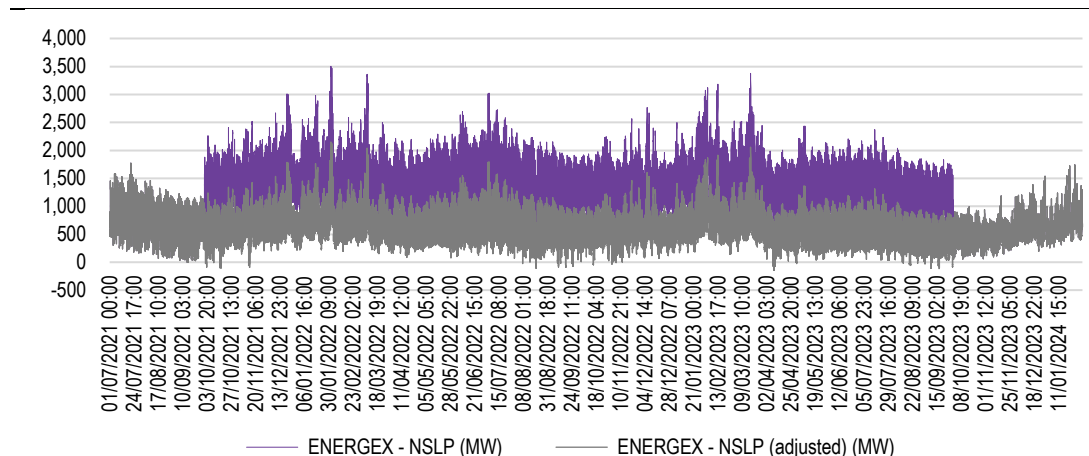
On balance, it is ACIL Allen's view that option 3 is the appropriate option to adopt.

By adopting option 3, the temporary artificial step change in the NSLP needs to be removed. This is done by calculating an adjustment based on the observed change (in terms of magnitude and spread) in NSLP demands between the three months prior to the artificial uplift and the first three months with the artificial uplift. This time period is chosen to calculate the adjustment because it minimises the risk

of including other fundamental change in consumer demand patterns. Using a longer period of data to calculate the adjustment factor could include changes unrelated to the temporary artificial uplift, such as the continued uptake of rooftop PV or rollout of interval meters.

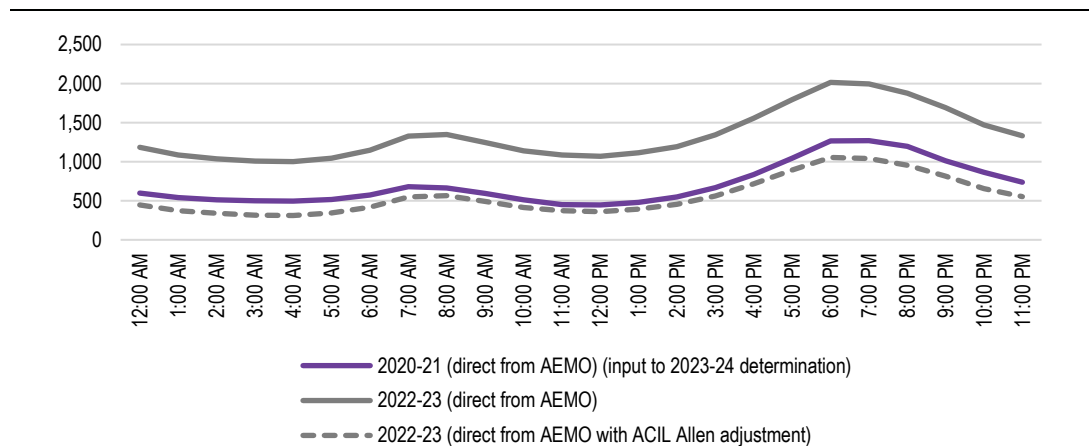
The adjustment is then applied to the Energex NSLP loads over the entire period of the temporary artificial uplift to remove the uplift. Figure 2.5 and Figure 2.6 show the effect of the adjustment which results in a profile not dissimilar to the shape of the NSLP prior to AEMO applying the temporary artificial uplift.

Figure 2.5 Energex NSLP (MW) – July 2021 to January 2024



Source: ACIL Allen analysis of AEMO data

Figure 2.6 Average time of day profile (MW) – 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 2024-25 we use our March 2024 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 2024-25 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 2024-25

Assumption	Details			
Macro-economic variables	<ul style="list-style-type: none"> — Exchange rate of AUD to USD 0.7 AUD/USD for 2024-25. — 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. — International thermal coal prices are assumed to converge from current levels of about USD\$150/t to USD\$120/t by 2024. 			
Electricity demand	Rooftop PV ACIL Allen's in-house model of Rooftop PV uptake: <ul style="list-style-type: none"> — NEM-wide Rooftop PV uptake is within 5 per cent of AEMO's Central forecast in 2024-25. 	Rooftop PV ACIL Allen's in-house model of Rooftop PV uptake: <ul style="list-style-type: none"> — NEM-wide Rooftop PV uptake is within 5 per cent of AEMO's Central forecast in 2024-25. 	Rooftop PV ACIL Allen's in-house model of Rooftop PV uptake: <ul style="list-style-type: none"> — NEM-wide Rooftop PV uptake is within 5 per cent of AEMO's Central forecast in 2024-25. 	Electric vehicles <ul style="list-style-type: none"> — Equivalent to AEMO 2023 ESOO Central scenario
Electricity supply (beyond new supply driven by state based schemes)	Assumed new entry and closures <ul style="list-style-type: none"> — Committed or likely committed generator closures included where the closure has been announced by the participant (Eraring in 2025). 	Assumed new entry and closures Committed or likely committed generator closures included where the closure has been announced by the participant (Eraring in 2025) .		
Gas prices into gas-fired power stations	For 2024-25, the modelling assumes \$11-12/GJ in the non-winter months, and \$13-15/GJ in the winter months for CCGTs. And for OCGTs, the modelling assumes \$17-18/GJ in the non-winter months, and \$21-22/GJ in the winter months. Although the gas price cap of \$12/GJ, as part of the Government's response to high electricity prices, remains in place for 2024-25, the modelling assumes peaking plant (and CCGTs in Winter) purchase their marginal gas (beyond contracted volumes) on a short term basis and hence are exempt from the price cap.			
Coal prices into coal-fired power stations	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 2024-25, domestic coal prices are assumed to be AUD\$135/tonne.			
Marginal loss factors	ACIL Allen's projections of average annual marginal loss factors (MLF) by generator DUID, developed using commercial power flow software.			

Constraints	<p>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.</p>
Generator availability	<p>PowerMark includes a planned maintenance schedule and a set of random unplanned outages for each generator:</p> <ul style="list-style-type: none"> — The latest MTPASA available at the time the Reference case is developed is adopted for planned maintenance. — 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. — Black coal plants are generally assumed to have planned maintenance schedules that equate to about one month every two years. — 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. — For mid merit gas plant, about 95 per cent based on annual maintenance requirements and assumed forced outage rates. — 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. — 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	Rye Park WF	Wind	396	Q1 2024
2	NSW1	Flyers Creek WF	Wind	145	Q1 2024
3	QLD1	Kidston Storage Hydro	Pumped Hydro	250	Q3 2024
4	QLD1	Macintyre Wind Farm	Wind	923	Q4 2024
5	QLD1	Wambo WF	Wind	250	Q1 2024
6	QLD1	Karara WF	Wind	103	Q1 2024
7	SA1	Goyder South WF	Wind	100	Q3 2024
8	NSW1	Wollar Solar Farm	Solar	280	Q2 2024
9	NSW1	Wellington North Solar Farm	Solar	300	Q3 2024
10	VIC1	Wunghnu Solar Farm	Solar	80	Q3 2024
11	NSW1	Waratah Super Battery	Battery	850	Q1 2025
12	NSW1	Stubbo Solar Farm	Solar	400	Q1 2024
13	QLD1	Tarong West Wind Farm	Wind	500	Q1 2026
14	VIC1	Kiamal Solar Farm Stage 2	Solar	150	Q1 2025
15	VIC1	Glenrowan Solar Farm	Solar	102	Q1 2024
16	VIC1	Derby Solar Farm	Solar	95	Q1 2024
17	VIC1	Fulham Solar Farm	Solar	80	Q1 2025
18	VIC1	Frasers Solar Farm	Solar	77	Q1 2024
19	VIC1	Horsham Solar Farm	Solar	118.8	Q1 2025
20	VIC1	Derby Battery	Battery	85	Q1 2025
21	VIC1	Fulham Battery	Battery	80	Q1 2025
22	VIC1	Kiamal Battery	Battery	150	Q1 2025
23	VIC1	Horsham Battery	Battery	50	Q1 2025
24	QLD1	Herries Range Wind Farm	Wind	1000	Q1 2026
25	VIC1	Golden Plains Wind Farm	Wind	756	Q3 2025
26	QLD1	Western Downs Battery	Battery	200	Q3 2024
27	SA1	Blyth Battery	Battery	200	Q4 2024
28	NSW1	Liddell Battery	Battery	250	Q1 2025
29	VIC1	Gnarwarre Battery	Battery	250	Q1 2025
30	VIC1	Mortlake Battery	Battery	300	Q1 2025
31	SA1	Bungama Battery	Battery	200	Q3 2024
32	QLD1	Mt Fox Battery	Battery	300	Q1 2025
33	NSW1	Walla Walla Solar Farm	Solar	300	Q2 2024

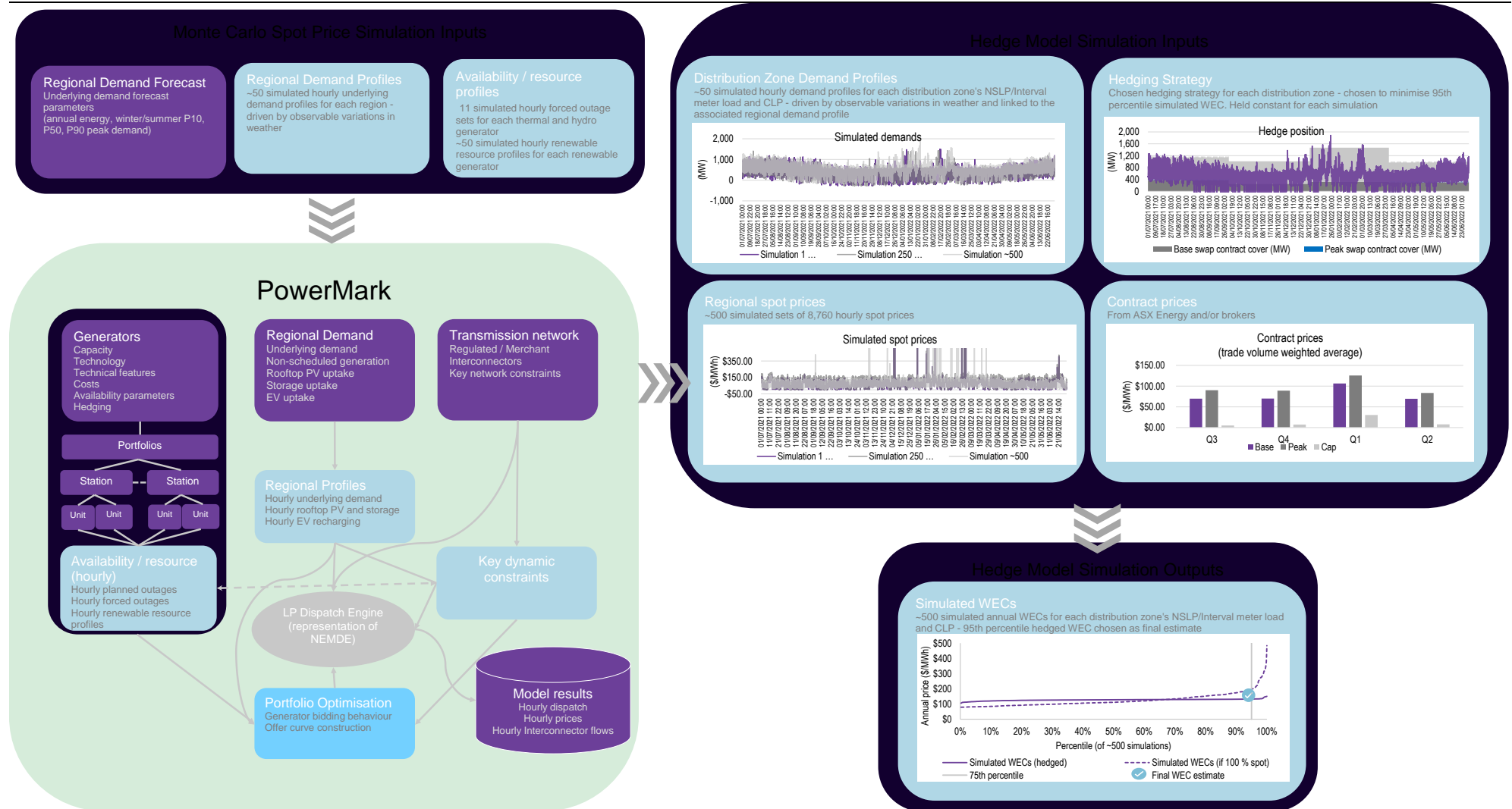
ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
34	NSW1	Big Canberra Battery Discharge	Battery	250	Q1 2026
35	VIC1	Rangebank Battery Discharge	Battery	200	Q1 2025
36	NSW1	Coppabella Wind Farm	Wind	275	Q1 2024
37	NSW1	Limondale Battery Discharge	Battery	50	Q1 2026
38	VIC1	Girgarre Solar Farm	Solar	93	Q3 2024
39	NSW1	New England Solar Farm Stage 2	Solar	320	Q1 2026
40	QLD1	Ardranda photovoltaic	Solar	175	Q1 2025
41	QLD1	Ardranda Battery	Battery	200	Q1 2025
42	QLD1	Aldoga Solar Farm	Solar	380	Q4 2025
43	QLD1	Chinchilla Battery	Battery	100	Q1 2024
44	QLD1	Brigalow Peaking Power Plant	Natural gas	400	Q1 2026
45	VIC1	Koorangie Energy Storage System	Battery	185	Q2 2025
46	SA1	Mannum Solar Farm 2	Solar	30	Q4 2023
47	QLD1	Moah Creek Wind Farm	Wind	372	Q3 2025
48	NSW1	Orana BESS	Battery	415	Q4 2025
49	NSW1	Smithfield BESS	Battery	65	Q4 2025
50	VIC1	The Melbourne Renewable Energy Hub	Battery	600	Q4 2025

Source: ACIL Allen

Summary infographic of the approach to estimate the WEC

Figure 2.7 provides an infographic type summary of the data, inputs, and flow of the market-based approach to estimating the WEC.

Figure 2.7 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: $WEC_p = DWP_p * WEC_t / DWPt$.

That is, the WEC_p equals the ratio WEC_t for the total (t) demand profile to the $DWPt$ for the total demand profile, multiplied by the spot DWP_p 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 2.8 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.

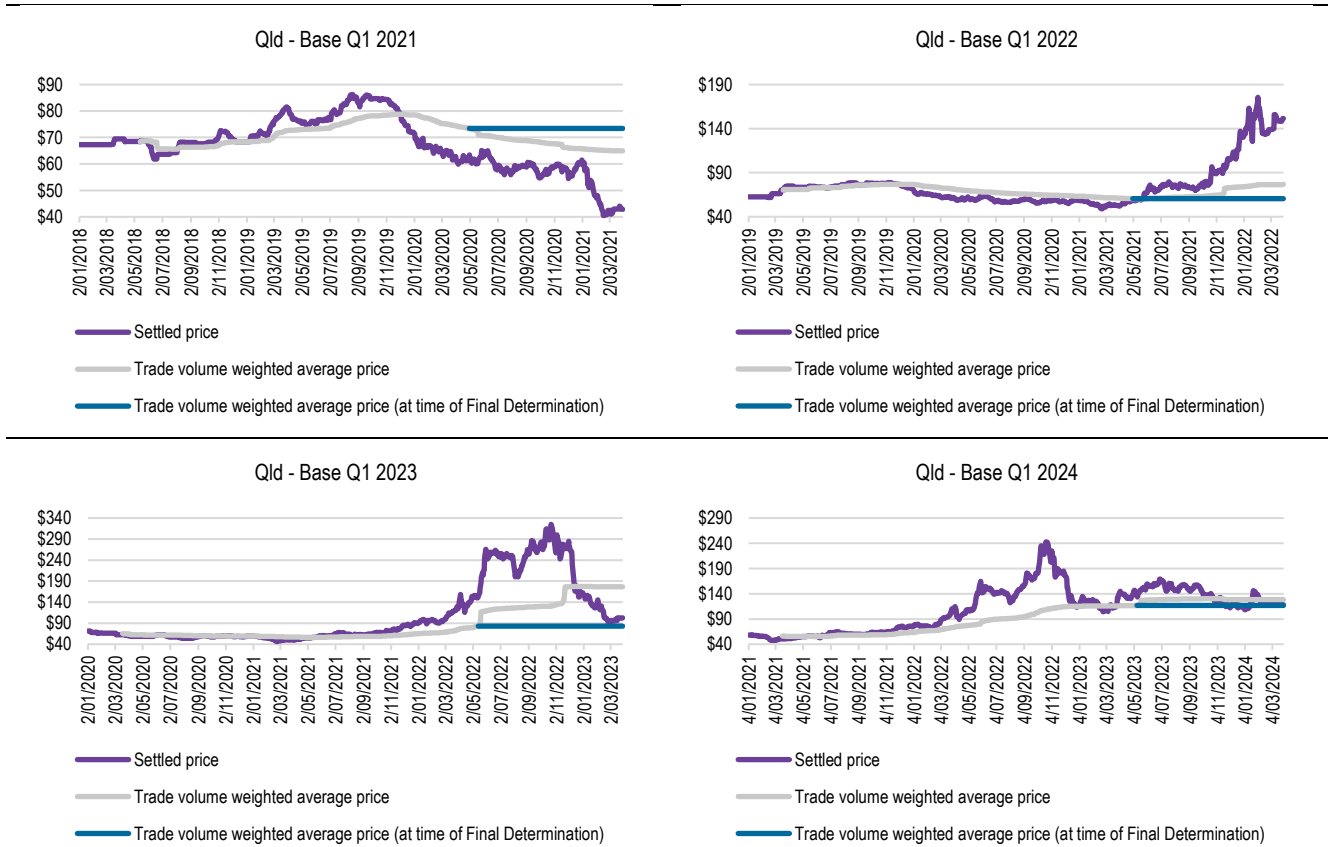
After the date the 2020-21 Final Determination was made, Q1 2021 traded prices decreased consistently resulting in an actual trade weighted average price about \$8.50 lower than that used in the Final Determination. This is an example of a decreasing market price environment – resulting in an overestimate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

After the date the 2023-24 Final Determination was made, Q1 2024 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 relatively stable market price environment post Final Determination (at least in terms of the trade weighted average price) – resulting in a reasonably close estimate.

Figure 2.8 Daily settlement prices and trade volume weighted prices (\$/MWh) for Q1 base contracts in Queensland



Source: ACIL Allen analysis of ASX Energy data

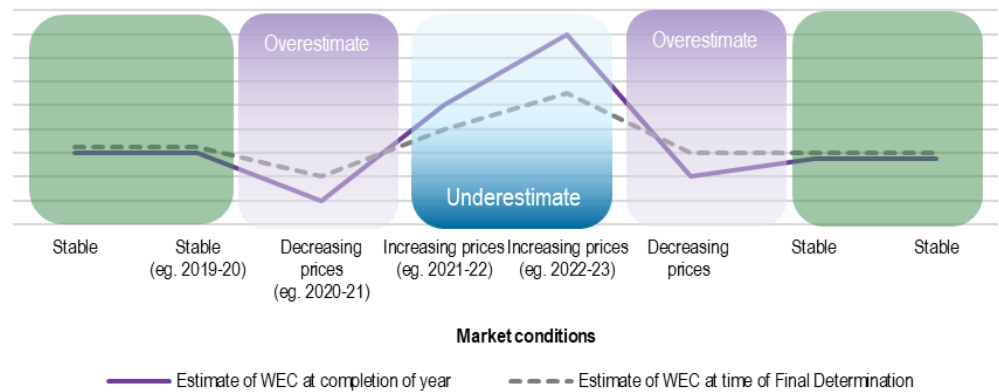
The graphs in Figure 2.8 demonstrate a number of important points about the WEC estimation methodology:

- 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 2.9.

Figure 2.9 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.

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, IT upgrade costs associated with 5MS and the NEM 2025 Reform Program.

The approach for estimating market fees is to make use of AEMO’s latest budget report. AEMO’s 2024-25 draft budget report was released in April 2024 and adopted for the Final Determination.

In the Draft Determination, fees published in AEMO's budget that are expressed as a cost per connection per week (referred to as fixed charges), were 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). This in effect assumes the same consumption volume per customer. However, for this Final Determination, we have adjusted the approach by not converting the weekly charges to a variable \$/MWh charge to better reflect the practices of retailers when billing customers. This adjustment to the approach also allows for a more accurate estimate of the NEM fees since no assumptions are made about the consumption volume of each customer. The variable NEM fees contained in AEMO's budget continue to be expressed in \$/MWh terms in this Final Determination.

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:

$$\text{MCL} = \text{OSL} + \text{PML}$$

Where for the Summer (December to March), Winter (April⁴ 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 $2.5\% \times (42/365) = 0.288$ 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 4.35 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 ES00, 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.

⁴ In the Draft Determination, April was classified as a Shoulder month, in this Final Determination April is classified as a Winter month, consistent with AEMO's MCL classification.

The RRO is currently not triggered for 2024-25 in Queensland, and hence we are not required to account for the RRO in the wholesale costs for 2024-25. 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 2015⁵.

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 is 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 it is apparent that there is a lag between the time the direction event occurs and final settlement.

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

⁵ https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2015/direction-recovery-reconciliation-file-v13.pdf

To arrive at the estimate of the AEMO Direction compensation costs, ACIL Allen takes the sum of the quarterly Direction costs by region for the most recent past four quarters, as presented in AEMO's latest available Quarterly Energy Dynamics Report (the latest report available at the time of undertaking our analysis for the 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 2023⁶, 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 excluded from the usual RERT and Directions costs (to avoid double counting).

As with the 2023-24 Determination, we continue to use AEMC's published compensation costs (in \$ terms) and allocate 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 were published prior to the 2023-24 Final Determination cut-off date of 10 May 2023 were included in the 2023-24 Final Determination energy costs. Any outstanding compensation amounts published after the cut-off date will be included in future determinations. However, as of 3 May 2024, there have been no published compensation amounts since 10 May 2023, and hence this cost component is set to zero for 2024-25 Final Determination.

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.

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

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

Market-based approach

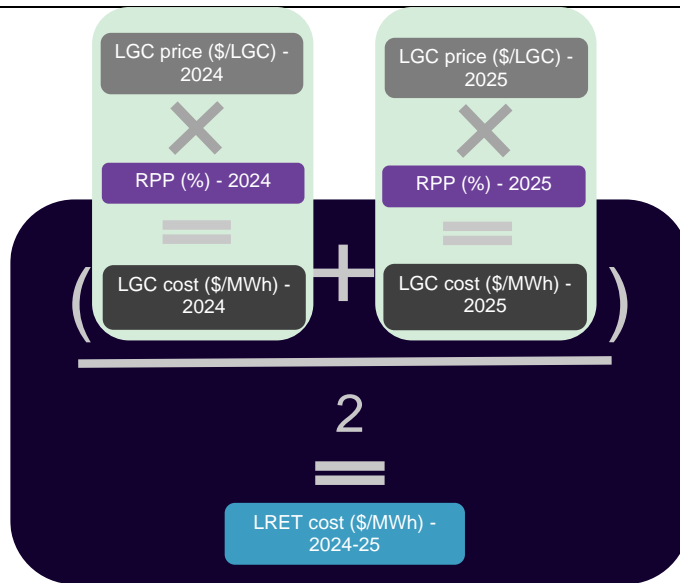
A market-based approach is used to determine the price of a LGC, which assumes that an efficient and prudent electricity retailer builds up LGC coverage prior to each compliance year.

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

To estimate the costs to retailers of complying with the LRET for 2024-25, ACIL Allen uses the following elements:

- The average of the trade-weighted average of LGC forward prices for 2024 and 2025 from brokers TraditionAsia
- the Renewable Power Percentage (RPP) for 2024, published by the CER
- the estimated Renewable Power Percentage (RPP) for 2025⁷.

Figure 2.10 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.

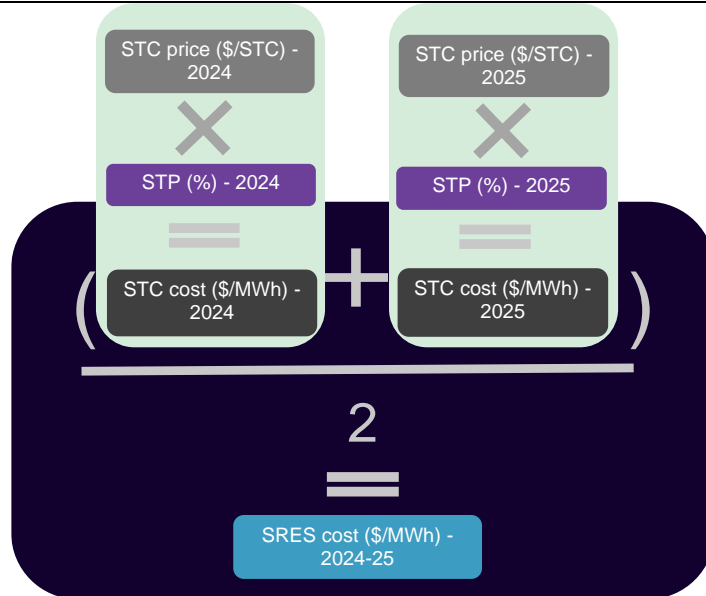
The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

⁷ The estimated RPP value for 2025 is estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2024 and 2025.

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

- the binding Small-scale Technology Percentage (STP) for 2024 as published by the CER
- an estimate of the STP value for 2025⁸
- CER clearing house price⁹ for 2024 and 2025 for Small-scale Technology Certificates (STCs) of \$40/MWh.

Figure 2.11 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.

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

⁸ The STP value for 2025 is estimated using estimates of STC creations and liable acquisitions in 2025, taking into consideration the CER's non-binding estimate.

⁹ 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.

point to a network based on their location. Average distribution losses are already summarised by network area in the AEMO publication.

As described by AEMO¹⁰, 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:

$$\text{Price at load connection point} = \text{RRN Price} * (\text{MLF} * \text{DLF})$$

The MLFs and DLFs used to estimate losses for the Final Determination for 2024-25 are based on the final 2024-25 MLFs and draft DLFs published by AEMO in April 2024.

¹⁰ See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

Responses to submissions to the Draft Determination

3

The QCA forwarded to ACIL Allen six 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 2024-25 Final Determination. A summary of the review is shown below in Table 3.1.

No issues were raised that required the attention of ACIL Allen.

Table 3.1 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	B Sutherland	Nil	Nil	Nil	Nil	Nil	Nil
2	Bundaberg Regional Irrigators Group	Nil	Nil	Nil	Nil	Nil	Nil
3	Electric Vehicle Council	Nil	Nil	Nil	Nil	Nil	Nil
4	M Knight	Nil	Nil	Nil	Nil	Nil	Nil
5	Origin Energy	Nil	Nil	Nil	Nil	Nil	Nil
6	Queensland Farmers Federation	Nil	Nil	Nil	Nil	Nil	Nil

Note: Yes = an issue was raised that required ACIL Allen's consideration

Source: ACIL Allen analysis of QCA supplied documents

Estimation of energy costs

4

4.1 Introduction

In this chapter we apply the methodology described in Chapter 2, and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the load profiles for 2024-25.

4.1.1 Historic demand and energy price levels

Figure 4.1 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 six 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:

- 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 then declined to about AUD\$25/GJ.
- This resulted in wholesale electricity prices averaging around \$145/MWh in Queensland.
- We observe some impacts of the Government's December 2022 intervention of capping coal and gas prices, on wholesale electricity spot prices.

In 2023-24 to date:

- Export coal prices declined further to about USD\$130/t.
- LNG netback prices declined further to about AUD\$15/GJ from the beginning of the 2023-24 financial year.
- This resulted in wholesale electricity prices reducing by about 45 per cent, averaging around \$78/MWh in Queensland.

In relation to each profile, we note the following:

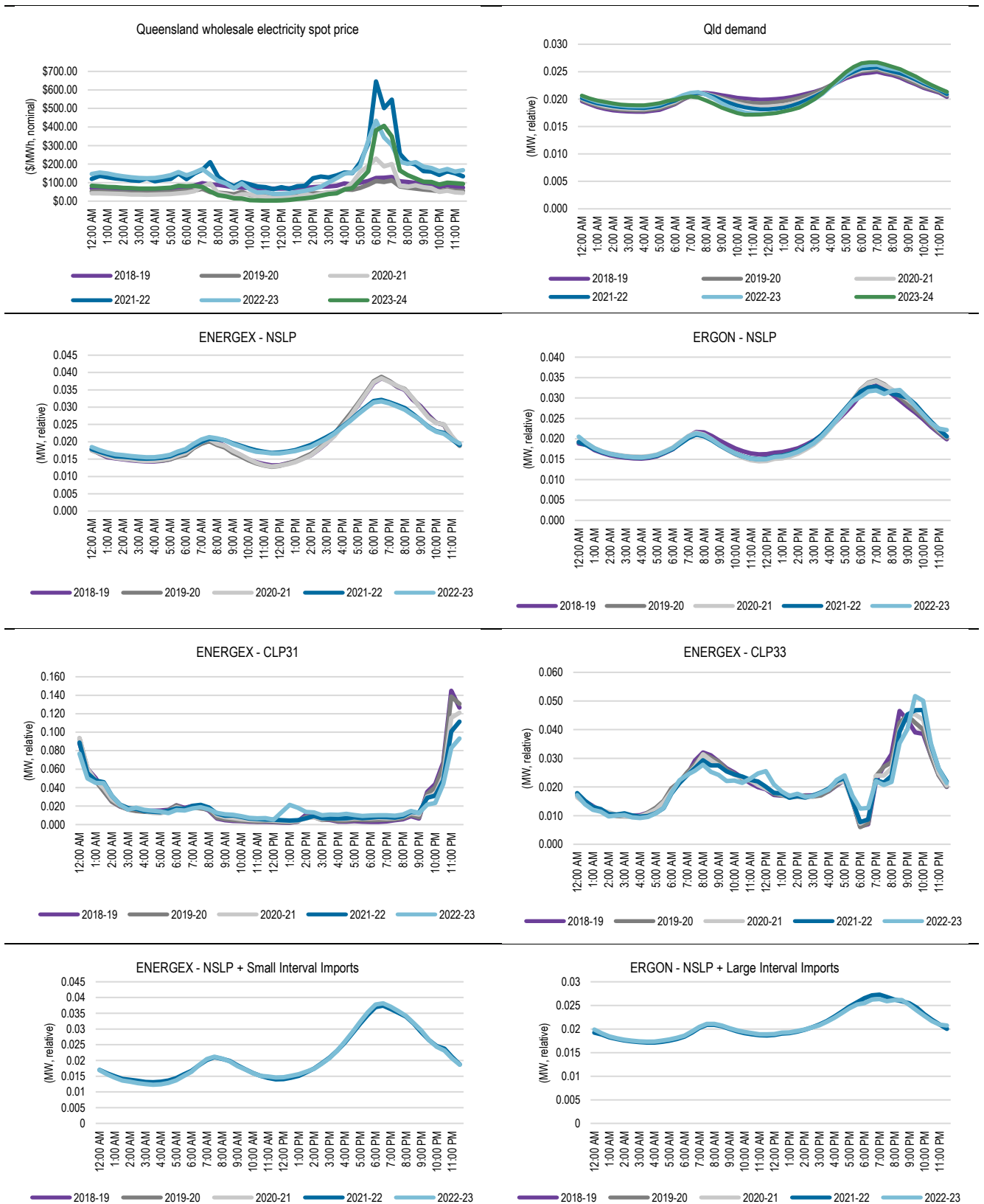
- The annual time of day price profile has been volatile over the past decade – with the overall level and shape of the price profile changing from one year to the next. For example, in 2021-22 the time-of-day profile was much more volatile compared with the very flat profile of 2018-19.
- Wholesale 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/MWh¹¹, 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. 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.

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.

- 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 prices¹² (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP). The carving out of the NSLPs during daylight hours increases the relative weighting of the load profile during the higher priced evening peak and reduces the relative weighting during the lower priced daylight hours.
- However, over the past few years the rate of carve out of the NSLP load during daylight hours has stopped, 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. It can be seen that when combining the NSLP and interval meter data, the trend in carve out of demand during daylight hours has slowed – reflecting the separation of the PV exports from the profile since October 2021.

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

Figure 4.1 Actual average time of day wholesale electricity spot price (\$/MWh, nominal) and load profiles (MW, relative) – Queensland – 2018-19 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. 2023-24 price and Queensland demand series includes data up to February 2024. Insufficient NSLP/CLP/interval meter load data available for 2023-24 and hence excluded.

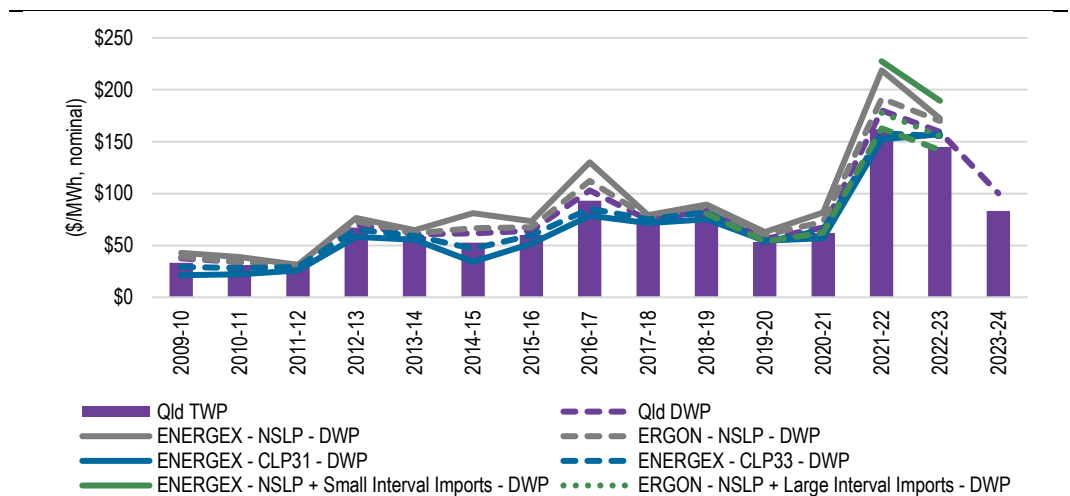
Source: ACIL Allen analysis of AEMO data

Figure 4.2 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 23 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 30 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.

Figure 4.2 Actual annual average demand weighted price (\$/MWh, nominal) by profile and Queensland time weighted average price (\$/MWh, nominal) – 2009-10 to 2023-24



Note: Values reported are spot (or uncontracted) prices. 2023-24 price series includes data up to February 2024. Insufficient NSLP/CLP/Interval meter data available for 2023-24.

Source: ACIL Allen analysis of AEMO data

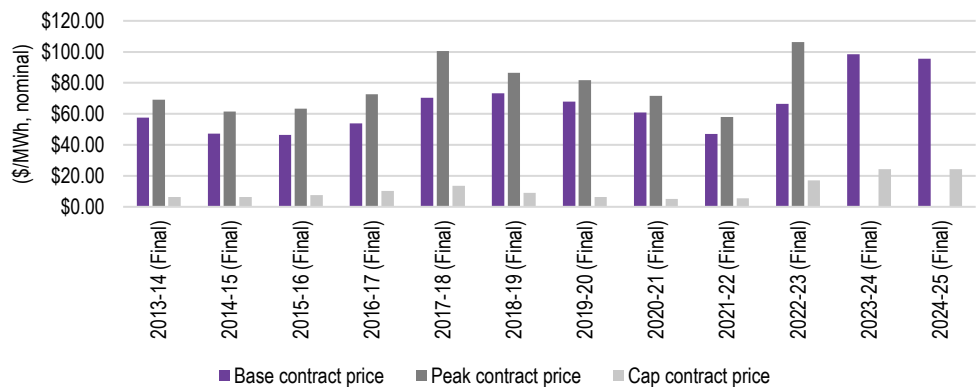
The volatility of spot prices (timing and incidence) provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer’s exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) used in the methodology does not change from 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 4.3 shows that compared with 2023-24, futures base contract prices for 2024-25, on an annualised and trade weighted basis to date, have decreased by about \$2.70/MWh for Queensland. Cap contract prices have increased by about \$0.10/MWh. A decrease in base prices (which take into account price volatility as well as underlying price outcomes) and an increase in

cap prices suggests the market is expecting slight growth in price volatility in 2024-25 during the evening peaks, offset by an increase in carve out (reduction) of daytime prices due to the continued uptake of rooftop PV and commissioning of further utility scale solar projects (which lowers prices during daylight hours).

The cost of hedging the NSLP and small interval meter load will be further exacerbated by the expected continued uptake of rooftop PV carving out the Queensland system demand during daylight hours, coupled with the commissioning of over 4,000 MW of utility scale solar. These two factors result in very low spot price outcomes during daylight hours - much less than the base contract price, meaning that the retailer will need to pay its contract counterparty for the difference between the base contract price and the very low spot price when it is over hedged.

Figure 4.3 Queensland Base, Peak, and Cap trade weighted average contract prices (\$/MWh, nominal) – 2013-14 to 2024-25



Source: ACIL Allen analysis of ASX Energy Data

4.2 Estimation of the Wholesale Energy Cost

4.2.1 Estimating contract prices

Contract prices for the 2024-25 year were estimated using the trade-weighted average of ASX Energy settlement prices of individual trades of contracts and exercised base call¹³ options (including the trade weighted average premium for exercised and expired base options) since the contract was listed up until 3 May 2024 inclusive. The inclusion of exercised options' strike prices and option premiums in this determination as per the 2023-24 determination is a refinement of the methodology and reflects the increasing use of options in the futures market over the past 12-24 months. Exercised base options contribute about 16 per cent of the traded volume of base 2024-25 contracts.

Table 4.1 shows the estimated quarterly swap and cap contract prices for 2023-24 and 2024-25. Trade weighted average base contract prices have stabilised between 2023-24 to 2024-25 and there is a moderate increase in the trade weighted average cap prices across quarters one and two.

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

	Q3	Q4	Q1	Q2
	2023-24			
Base	\$102.68	\$90.29	\$115.32	\$85.40

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

	Q3	Q4	Q1	Q2
Cap	\$20.02	\$22.05	\$37.20	\$17.88
	2024-25			
Base	\$96.17	\$87.24	\$111.73	\$87.71
Cap	\$18.60	\$20.17	\$39.48	\$19.42
	Percentage change from 2023-24 to 2024-25			
Base	-6%	-3%	-3%	3%
Cap	-7%	-9%	6%	9%

Source: ACIL Allen analysis using ASX Energy

The following charts show daily average settlement prices and trade volumes for 2024-25 ASX Energy quarterly base futures and cap contracts up to 3 May 2024.

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.

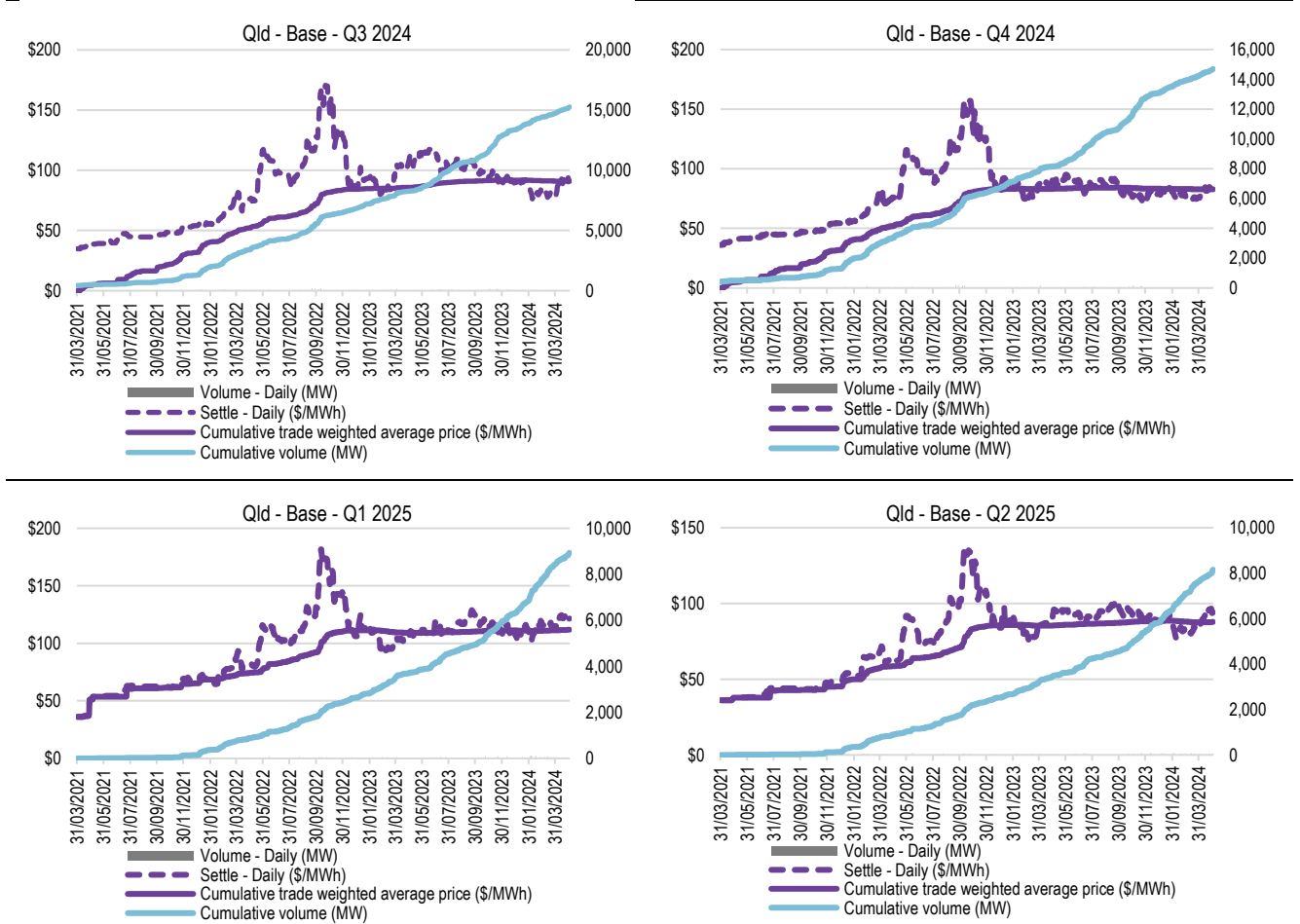
The announcement of the Government intervention in the form of coal and gas price caps has coincided with a decline in futures prices of between \$50 and \$100/MWh (depending on the quarterly product). However, given a reasonable portion of trades (to date) occurred prior to the announcement of the intervention in December 2022, the trade weighted average futures price has tended to stabilise to levels similar to those of the 2023-24 determination, rather than decrease since the announcement.

The relative stability of the daily settled contract prices over the past 12 months (compared with the period prior to the Government intervention) reflects the relative stability in coal and gas prices over the same period of time. That is, coincidentally or otherwise, coal and gas prices have remained at levels similar to the government price caps since the commencement of the intervention, and this has flowed through to daily settled contract prices.

That said, although daily settled contract prices declined substantially around December 2022, they have not declined to the lower levels observed in 2021 and the first half of 2022. This could be for several reasons, including:

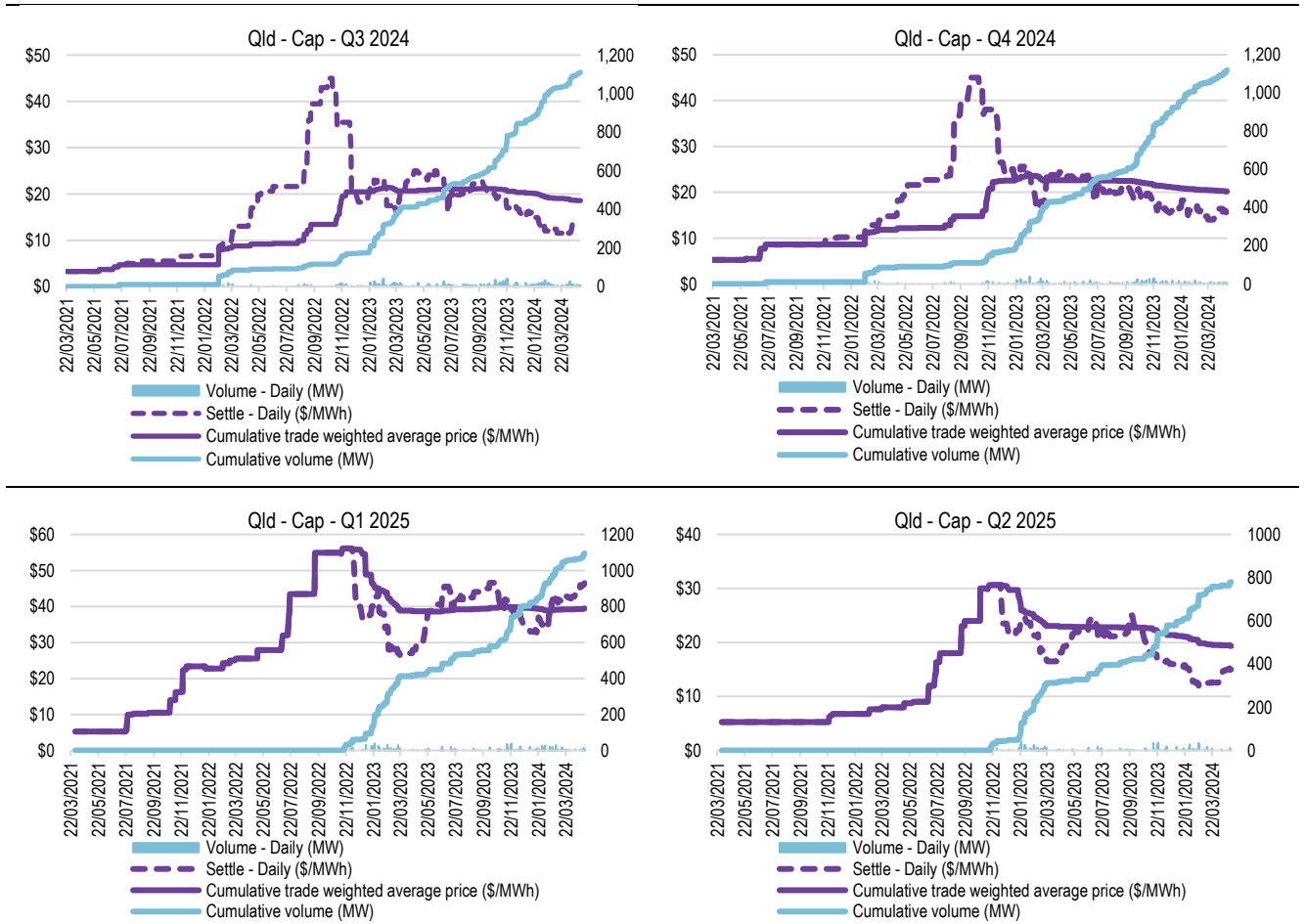
- current coal and gas prices are higher than what they were in 2021 and first half of 2022 (but lower than the second half of 2022)
- the market has been expecting further delays in the return to service of Callide C or further outages of other coal fired power stations
- the market was expecting a return to El Nino in 2024-25 and its associated impact on extreme weather driven demand outcomes.

Figure 4.4 Time series of trade volume and price – ASX Energy base futures - Queensland



Source: ASX Energy data

Figure 4.5 Time series of trade volume and price – ASX Energy \$300 cap futures - Queensland



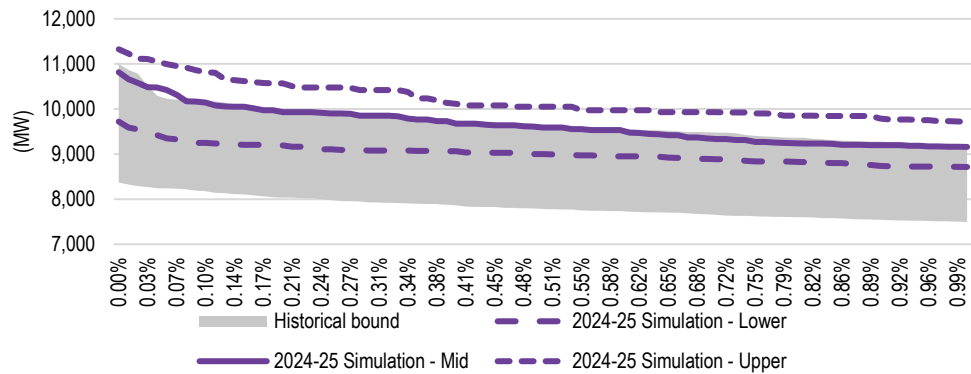
Source: ASX Energy data

4.2.2 Estimating wholesale spot prices

ACIL Allen’s proprietary electricity model, *PowerMark* was run to estimate the hourly spot prices for the 583 simulations (53 demand and 11 outage sets).

Figure 4.6 shows the range of the upper one percent segment of the demand duration curves for the 53 simulated Queensland system demand sets resulting from the methodology for 2024-25, 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 53 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2024-25 have a variation similar to that observed over the past 10 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 4.6 Comparison of upper one per cent of hourly loads of 2024-25 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 2024-25 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 2024-25 from AEMO’s ESOO includes some growth due to the commencement of electrification in some sectors of the economy, as well as uptake of EVs. 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.

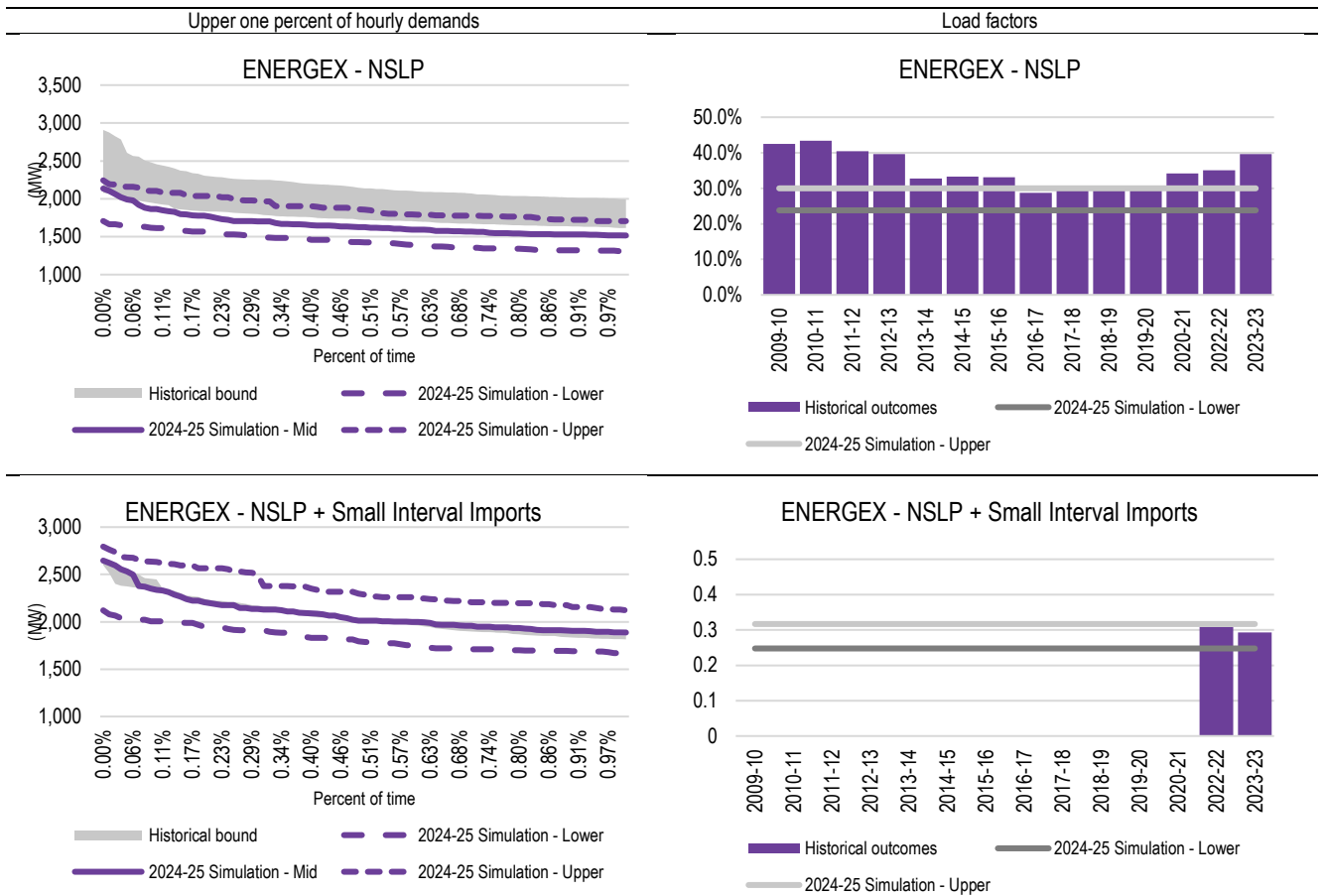
The left panels of Figure 4.7 shows the range of the simulated NSLP and interval meter peak demands for residential and small business customers is similar to recent actual outcomes. This variation results in the annual load factor¹⁴ of the 2024-25 simulated demand sets ranging between 25 percent and 32 percent compared with a range of 29 percent to 31 percent for the actual Energex NSLP and small customer interval meter demands (as shown in the right panels of Figure 4.7). It is not surprising the range in load factor across the simulated demand sets is greater than that of actual outcomes for the NSLP and small customer interval meter loads given we only have the two years of observable actual data.

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 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. There is a step up in the load factor of the Energex NSLP in 2021-22 reflecting the artificial uplift applied to the NSLP by AEMO.

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 4.7 Comparison of upper one per cent of hourly loads and load factors of 2024-25 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 4.8 compares the modelled annual regional TWP for the 583 simulations for 2024-25 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 2024-25 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 4.8) 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.

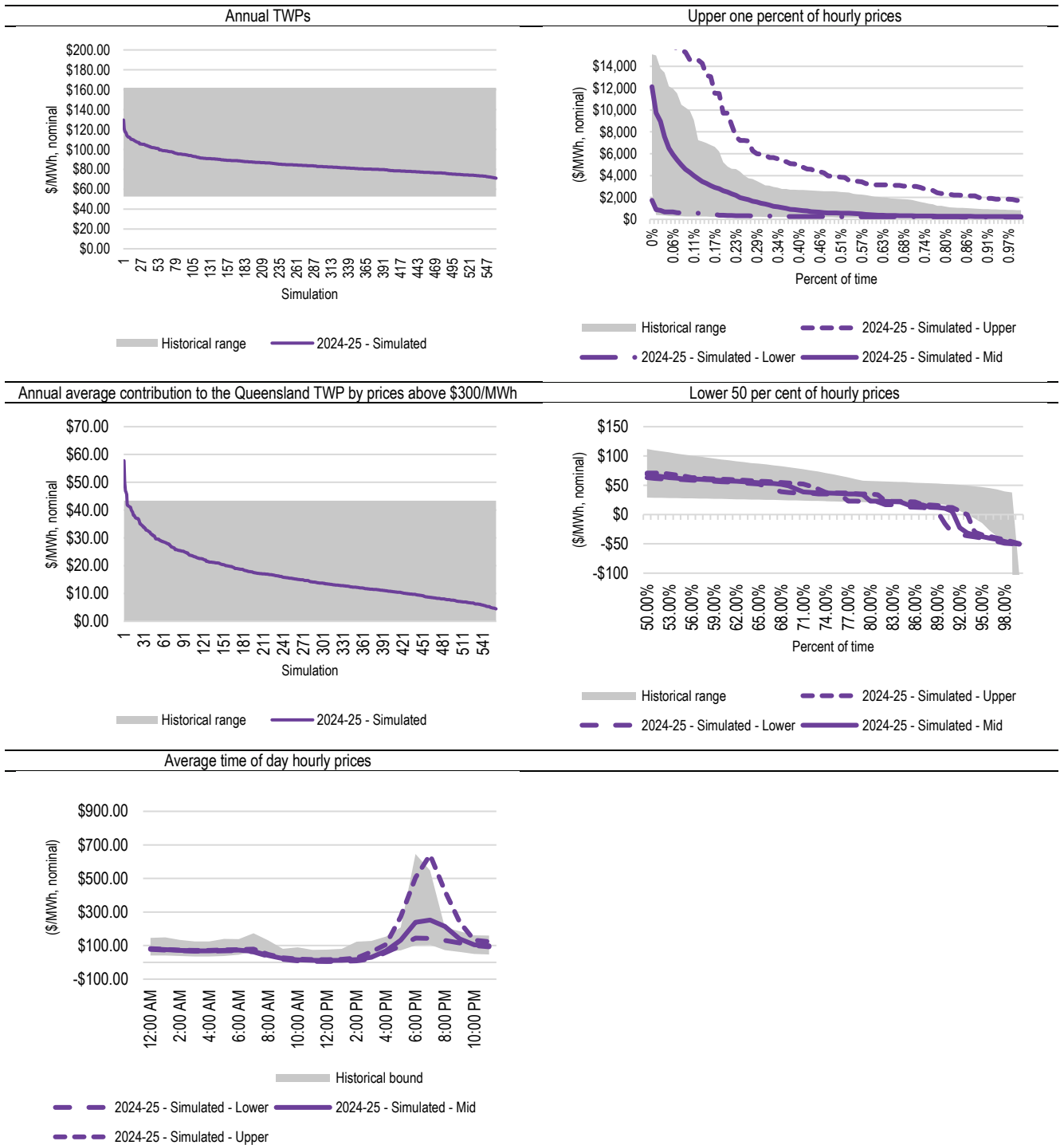
ACIL Allen is satisfied that PowerMark has performed adequately in capturing the extent and level of high price events based on the demand and outage inputs for the 583 simulations. The range in annual average contribution to the TWP, of hourly prices above \$300/MWh (shown in the mid left panel of Figure 4.8) for the 583 simulations is consistent with those recorded in history. For some of the 2024-25 simulations the contribution of price spikes is greater than historical levels, reflecting the general tightening of the demand-supply balance in the market during periods of lower availability of thermal and renewable power plant.

The mid right panel of Figure 4.8 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 2024-25 results in an increase in the proportion of hours in which the price is zero or negative.

The lower left panel of Figure 4.8 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 2024-25 during daylight hours.

Based on these metrics, ACIL Allen is satisfied that in an aggregate sense the distribution of the 583 simulations for 2024-25 cover an adequately wide range of possible annual spot price outcomes.

Figure 4.8 Comparison of various metrics of hourly prices from the 2024-25 simulations with historical outcomes – Queensland



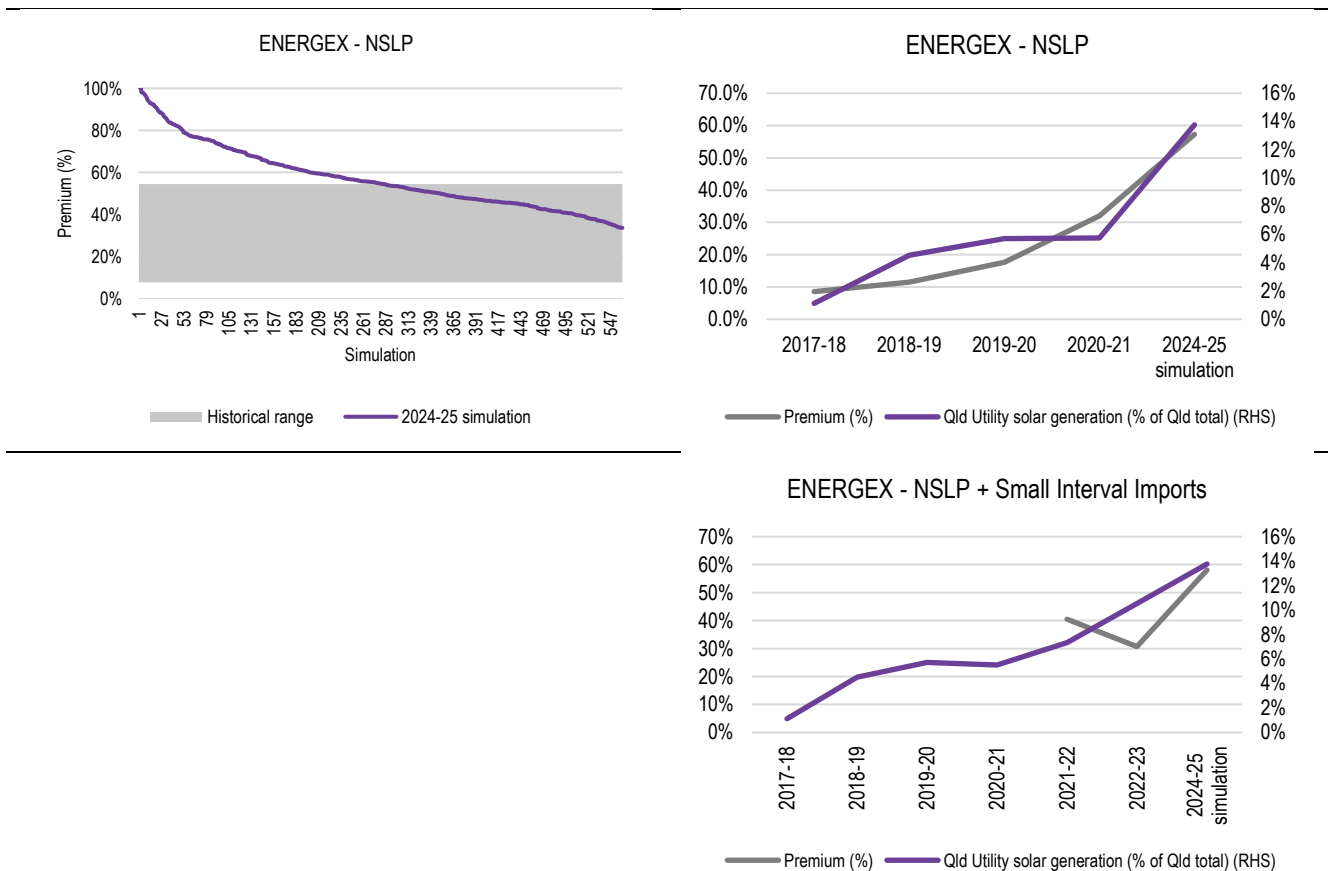
Source: ACIL Allen analysis and AEMO data

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 4.9 shows that, for the past six 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 the 583 simulations for 2024-25 for the NSLP, this percentage varies from 36 percent to 100 percent. The modelling suggests a greater range in the premium for 2024-25 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability coupled with 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 4.9 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 six years in Figure 4.9 demonstrates that the relationship between the NSLP demand and corresponding regional spot prices in the 583 simulations is sound.

Figure 4.9 Simulated annual DWP for Energex NSLP and small interval meter load as percentage premium of annual TWP for 2024-25 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 583 simulations cover the range of expected price outcomes for 2024-25 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 53 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 2024-25.

4.2.3 Applying the hedge model

The hedging methodology uses a simple hedge book approach based on standard quarterly base and peak swaps, and cap contracts. The prices for these hedging instruments are taken from the estimates provided in Section 4.2.1.

Contract volumes adopted for the hedging strategy for 2024-25 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 53 demand sets for the quarter.
- The cap contract volume is set at 90 per cent of the median of the annual peak demands across the 53 demand sets minus the base contract volumes. This is a slight decrease from the 2023-24 Determination and is due to the stronger increase in cap contract prices relative to base 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:

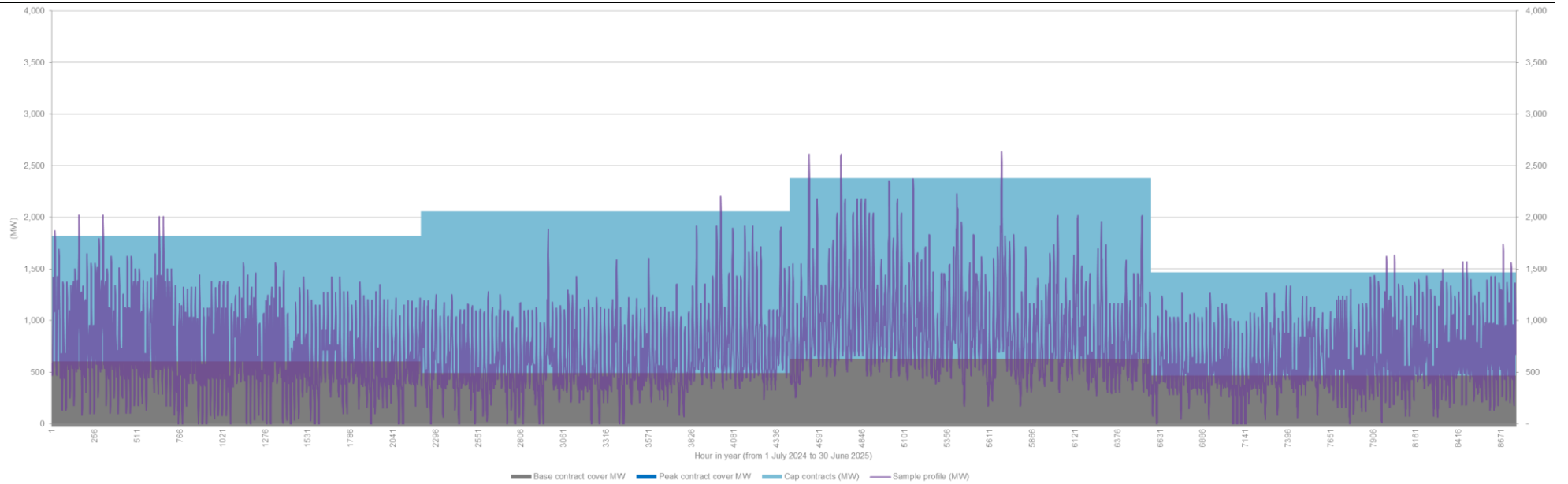
- The base contract volume is set to equal the 50th percentile of the off-peak period hourly demands across all 53 demand sets for the quarter.
- The cap contract volume is set at 70 per cent of the median of the annual peak demands across the 53 demand sets minus the base and peak contract volumes.

The same hourly hedge volumes (in MW terms) apply to each of the 53 demand sets for a given tariff class and year, and hence to each of the 583 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 53 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 583 simulations when calculating the wholesale energy cost. The contract volumes adopted for the Energex NSLP plus small interval meter load are shown in Figure 4.10. 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 contracts 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 4.10 Contract volumes used in hedge modelling of 583 simulations for 2024-25 for Energex NSLP + small interval meter import load

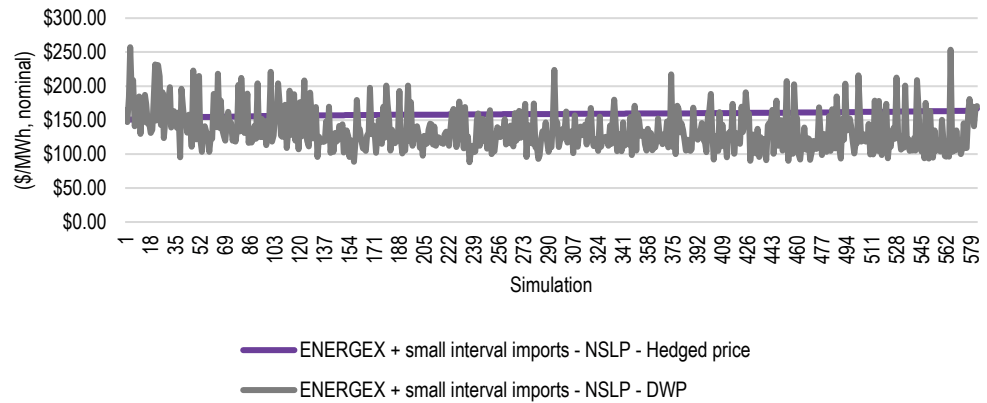


Source: ACIL Allen analysis

Figure 4.11 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 higher than the spot price outcomes in some of the simulations. This is a result of the trade weighted average contract prices being higher than the spot price simulations, and higher than the current consensus view of outcomes for 2024-25.

Figure 4.11 Annual hedged price and DWP (\$/MWh, nominal) for Energex NSLP + small interval meter load for the 583 simulations – 2024-25



Source: ACIL Allen analysis

4.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the final WEC estimate is taken as the 95th percentile of the distribution containing 583 WECs (the annual hedged prices). ACIL Allen’s estimate of the WEC for each tariff class for 2024-25 are shown in Table 4.2.

Table 4.2 Estimated WEC (\$/MWh, nominal) for 2024-25 at the regional reference node

Settlement class	2024-25 – Final Determination	2023-24 – Final Determination	Change from 2023-24 to 2024-25 (%)
Energex - Residential and small business	\$162.95	\$171.87	-5%
Energex - Controlled load tariff 9000 (31)	\$96.08	\$115.28	-17%
Energex - Controlled load tariff 9100 (33)	\$103.67	\$118.41	-12%
Energex - Unmetered supply	\$162.95	\$171.87	-5%
Ergon Energy - CAC and ICC	\$99.58	\$101.83	-2%
Ergon Energy - SAC demand and street lighting	\$114.53	\$124.20	-8%
Energex – Small business primary load control tariff	\$115.59	\$125.78	-8%
Ergon – Large business primary and secondary load control tariffs	\$103.67	\$118.41	-12%
Energex - Residential and small business - Time varying - Night	\$154.86	\$110.81	40%
Energex - Residential and small business - Time varying - Day	\$60.48	\$42.06	44%
Energex - Residential and small business - Time varying - Evening Peak	\$246.31	\$315.80	-22%

Source: ACIL Allen analysis

4.2.5 Do the changes in WEC make intuitive sense?

Given the strong decline in wholesale spot prices over the past 12 months, one might expect a stronger decline in the 2024-25 WECs compared with what has been presented in the previous sections.

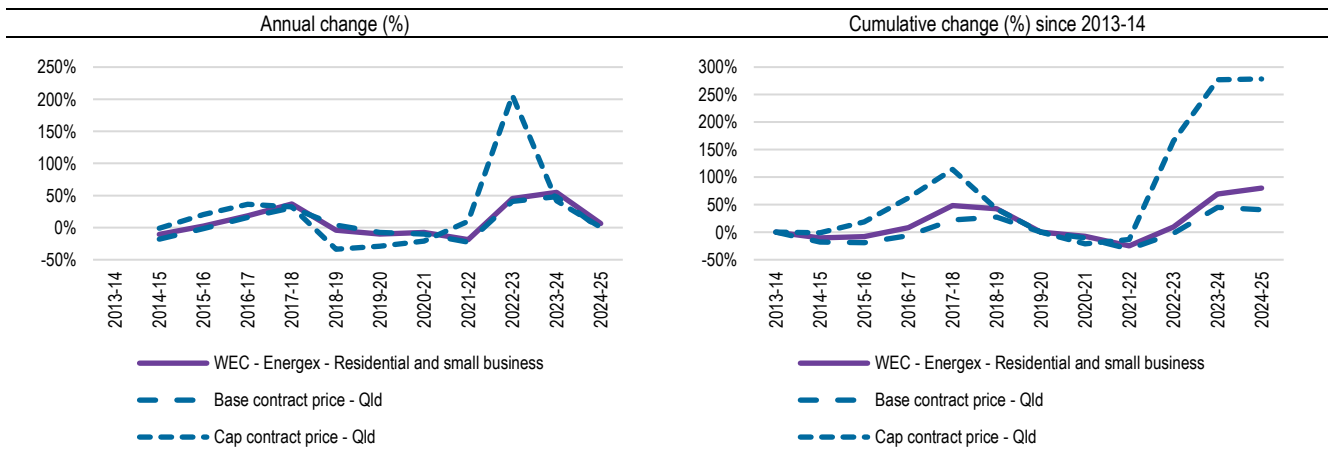
Hence the estimated WECs warrant further investigation to ensure the estimated changes align with what is observed in the market. The charts below plot the changes in WECs and trade weighted contract prices from this Final Determination together with previous final determinations.

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 contract 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 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 2024-25, and that the estimated WECs reflect the consensus view of market conditions for the given determination year in the two to three year period leading up to the time the determination was made – reflecting that retailers build up their hedge book over time, and in the case of 2024-25, purchased hedges in 2022-23 and 2023-24 when the expectation at that time was that prices in 2024-25 were going to remain at elevated levels.

Figure 4.12 Change in WEC and trade weighted contract prices (%) – 2013-14 to 2024-25



Note: Cumulative change uses 2013-14 as the base observation.

Source: ACIL Allen analysis

4.3 Estimation of renewable energy policy costs

Renewable energy scheme (RET)

The RET scheme consists of two elements – the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). Liable parties (i.e. all electricity retailers¹⁵) 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 2024 and 2025 calendar years, with the costs averaged to estimate the 2024-25 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 2024 and 2025 from brokers TraditionAsia
- estimated Renewable Power Percentages (RPP) values for 2024 and 2025 of 18.48 per cent¹⁶
- binding Small-scale Technology Percentage (STP) value for 2024 of 21.26 per cent, as published by CER
- estimated STP value for 2025 of 16.14 per cent¹⁷
- CER clearing house price¹⁸ for 2023 and 2024 for Small-scale Technology Certificates (STCs) of \$40/MWh.

4.3.1 LRET

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

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

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

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 2024 and 2025 are based on the CER's published RPP for 2024 and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2024 and 2025.

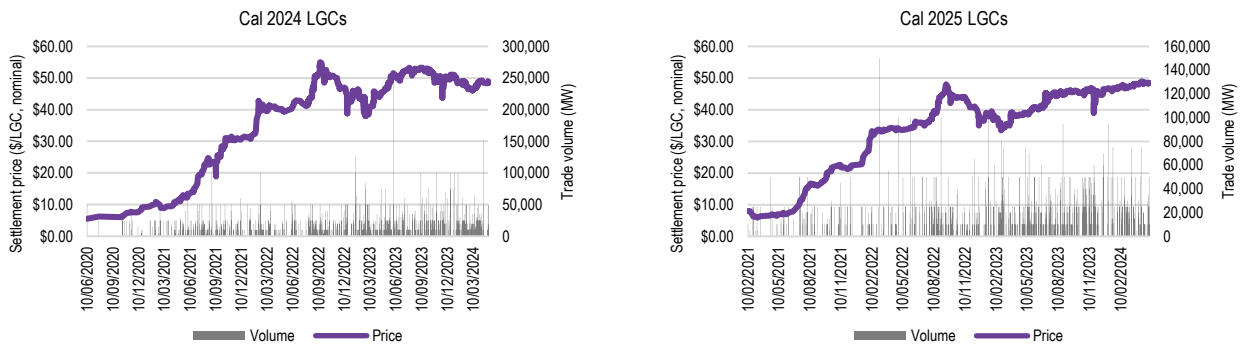
¹⁷ The STP value for 2025 is based on the CER's non-binding STP. Although ACIL Allen's estimate of the non-binding STP based on our engagement with the CER is 17.99 per cent, the QCA has asked ACIL Allen to adopt the published CER's non-binding STP value given that there is a true-up mechanism in place for the SRES costs (see <https://cer.gov.au/document/small-scale-technology-certificate-projections-report-acil-allen-november-2023>).

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.

ACIL Allen has estimated the average LGC price using LGC forward prices provided by broker TraditionAsia up to 3 May 2024.

The LGC price used in assessing the cost of the scheme for 2024-25 is found by taking the trade-weighted average of the forward prices for the 2024 and 2025 calendar years, respectively, since the contracts commenced trading. This is typically about 2.5 years prior to the commencement of the compliance year (see Figure 4.13). The average LGC prices calculated from the TraditionAsia data are \$41.97/MWh for 2024 and \$39.64/MWh for 2025.

Figure 4.13 LGC prices for 2024 and 2025 for 2024-25 (\$/LGC, nominal)



Source: ACIL Allen analysis of TraditionAsia data

The RPP value for 2025 is yet to be set by the CER. Therefore, the RPP value for 2025 is estimated by using the mandated target of 33 TWh and the CER’s published cumulative adjustment and estimate of electricity acquisitions in 2024 of 178.40 TWh. In other words, ACIL Allen has assumed electricity acquisitions remain constant in 2024 and 2025, and hence the RPP values for 2024 and 2025 are both 18.48 per cent.

Key elements of the 2024 and 2025 RPP estimation are shown in Table 4.3.

Table 4.3 2024 and 2025 RPP values

	2024	2025 (estimate based on 2024 RPP)
LRET target, MWh (CER)	33,981,880	33,981,880
Relevant acquisitions minus exemptions, MWh (CER)	178,400,000	178,400,000
Estimated RPP	18.48%	18.48%

Source: ACIL Allen analysis of CER and AEMO data

ACIL Allen calculates the cost of complying with the LRET in 2024 and 2025 by multiplying the RPP values for 2024 and 2025 by the trade volume weighted average LGC prices for 2024 and 2025, respectively. The cost of complying with the LRET in 2024-25 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be \$7.54/MWh in 2024-25 as shown in Table 4.4.

Table 4.4 Estimated cost of LRET – 2024-25

	2024	2025	Cost of LRET 2024-25
RPP %	18.48%	18.48%	

	2024	2025	Cost of LRET 2024-25
Trade weighted average LGC price (\$/LGC, nominal)	\$41.97	\$39.64	
Cost of LRET (\$/MWh, nominal)	\$7.76	\$7.33	\$7.54

Source: ACIL Allen analysis of CER and TraditionAsia data

4.3.2 SRES

The cost of the SRES is calculated by applying the estimated STP value to the STC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2024-25.

ACIL Allen estimates the cost of complying with SRES to be \$7.48/MWh in 2024-25 as set out in Table 4.5.

Table 4.5 Estimated cost of SRES – 2024-25

	2024	2025	Cost of SRES 2024-25
STP %	21.26%	16.14%	
STC clearing house price (\$/STC, nominal)	\$40.00	\$40.00	
Cost of SRES (\$/MWh, nominal)	\$8.50	\$6.46	\$7.48

Source: ACIL Allen analysis of CER data

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2024-25 as set out in Table 4.6.

Since the 2023-24 estimate, the cost of LRET has increased by around 1.3 per cent, driven by slightly higher LGC prices in 2024-25, and the cost of SRES has increased by 9 per cent, driven by the increase in the STP.

Table 4.6 Total renewable energy policy costs (\$/MWh, nominal) – 2024-25

	2023-24	2024-25
LRET	\$7.44	\$7.54
SRES	\$6.86	\$7.48
Total	\$14.30	\$15.02

Source: ACIL Allen analysis

4.4 Estimation of other energy costs

The estimates of other energy costs for the 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).

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA), DER, IT system upgrades for 5MS and the NEM 2025 Reform Program.

The estimate for the NEM management fees is taken from AEMO's 2024-25 budget and fees report.

Based on the fees provided by AEMO's *Draft FY25 Budget and Fees April 2024*, we estimate the total NEM fees for 2024-25 to be \$0.50/MWh and \$0.23/week for the variable and fixed components respectively. The breakdown of total fees is shown in Table 4.7.

Table 4.7 NEM management fees (\$, nominal) – 2024-25

Cost category	2023-24 (\$/MWh)	2024-25 (variable, \$/MWh)	2024-25 (fixed, \$/week)
NEM fees (admin, registration, etc.)	\$0.57	\$0.29525	\$0.09228
FRC - electricity	\$0.0802	\$0.00000	\$0.03609
ECA - electricity	\$0.0404	\$0.00000	\$0.01343
DER fee	\$0.02370	\$0.01344	\$0.00420
IT upgrade and 5MS/GS compliance	\$0.2438	\$0.0986	\$0.03082
National Electricity Market (NEM) 2025 Reform Program	\$0.000	\$0.0968	\$0.05151
Total NEM management fees	\$0.95	\$0.50409	\$0.22833

Source: ACIL Allen analysis of AEMO reports

4.4.2 Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs in Queensland over the preceding 52 weeks (as at 3 May 2024) of available NEM ancillary services data as a basis for 2024-25, the estimated cost of ancillary services is shown in Table 4.8.

Table 4.8 Ancillary services (\$/MWh, nominal) – 2024-25

Region	2023-24	2024-25
Queensland	\$0.47	\$0.21

Source: ACIL Allen analysis of AEMO data

4.4.3 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.

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:

$$\text{MCL} = \text{OSL} + \text{PML}$$

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

$$\text{OSL} = (\text{Average daily load} \times \text{Average future expected spot price} \times \text{Participant Risk Adjustment Factor} \times \text{OS Volatility factor} \times (\text{GST} + 1)) \times 35 \text{ days}$$

$$\text{PML} = (\text{Average daily load} \times \text{Average future expected spot price} \times \text{Participant Risk Adjustment Factor} \times \text{PM Volatility factor} \times (\text{GST} + 1)) \times 7 \text{ days}$$

Taking a 1 MWh average daily load and assuming the inputs in Table 4.9 for each season for the Energex NSLP and small interval meter load gives an estimated MCL of \$15211.

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 $\$15,211/42 = \$362.16/\text{MWh}$.

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 $2.5\% \times (42/365) = 0.288$ percent. Applying this funding cost to the single MWh charge of \$362.16 gives \$1.04/MWh.

The components of the AEMO prudential costs for Ergon NSLP and large interval meter load are shown in Table 4.10.

Table 4.9 AEMO prudential costs for Energex NSLP and small interval meter load – 2024-25

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price (\$/MWh, nominal)	\$118.82	\$104.98	\$64.86
Participant Risk Adjustment Factor	1.8253	1.6312	1.5008
OS Volatility factor	1.52	1.53	1.39
PM Volatility factor	2.86	2.26	1.88
OSL	\$17,146	\$12,884	\$6,381
PML	\$3,429	\$2,577	\$1,276
MCL	\$20,576	\$15,461	\$7,658
Average MCL		\$15,211	
AEMO prudential cost (\$/MWh, nominal)		\$1.04	

Source: ACIL Allen analysis of AEMO data

Table 4.10 AEMO prudential costs for Ergon NSLP and large interval meter load – 2024-25

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price (\$/MWh, nominal)	\$118.82	\$104.98	\$64.86
Participant Risk Adjustment Factor	0.9750	0.9709	0.9553
OS Volatility factor	1.52	1.53	1.39
PM Volatility factor	2.86	2.26	1.88
OSL	\$6,694	\$5,916	\$3,241
PML	\$1,339	\$1,183	\$648
MCL	\$8,032	\$7,099	\$3,889
Average MCL		\$6,608	
AEMO prudential cost (\$/MWh, nominal)		\$0.45	

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 4.35 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 21 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 4.11. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 8.90 per cent but adjusted for an assumed 4.35 per cent return on cash lodged with the clearing (giving a net funding cost of 4.55 percent) results in the prudential cost per MWh for each contract type.

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

Table 4.11 Hedge Prudential funding costs by contract type – Queensland 2024-25

Contract Type	Average contract price	Initial margin (rounded up to nearest \$1000)	Prudential cost per MWh
Base	\$95.65	\$51,000	\$1.06
Cap	\$24.35	\$26,000	\$0.54

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 4.12 and Table 4.13 respectively.

Table 4.12 Hedge Prudential funding costs for ENERGEX NSLP and small interval meter load – 2024-25

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	\$1.06	0.9268	\$0.98
Cap	\$0.54	0.5176	\$0.28
Total cost		\$1.26	

Source: ACIL Allen analysis

Table 4.13 Hedge Prudential funding costs for ERGON NSLP and large interval meter load – 2024-25

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	\$1.06	0.9268	\$0.98
Cap	\$0.54	0.5176	\$0.28
Total cost		\$1.26	

Source: ACIL Allen analysis

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2024-25 as set out in Table 4.14. Prudential costs for 2024-25 are lower than 2023-24 due to the exclusion of the rooftop PV export carveout from the demand profile.

Table 4.14 Total prudential costs (\$/MWh, nominal) – 2024-25

Jurisdiction	2023-24	2024-25
Energex NSLP and small interval meter load	\$3.81	\$2.30
Ergon NSLP and large interval meter load	\$2.24	\$1.71

Source: ACIL Allen analysis

4.4.4 Reliability and Emergency Reserve Trader (RERT)

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

Excluding the June 2022 NEM events, AEMO has not activated the RERT for the 12-month period prior to the Final Determination in Queensland.

Hence, the RERT costs for Queensland for the Final Determination are set at \$0.00/MWh.

4.4.5 June 2022 NEM events

To estimate the costs of the June 2022 NEM events, ACIL Allen uses AEMO’s published estimates of the costs of the June 2022 events, as well as AEMC’s final decisions on administered pricing compensation claims.

As at 3 May 2024 no updated finalised costs have been published since the 2023-24 Final Determination.

4.4.6 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.15 and Table 4.16, for the 2024-25 Determination and is compared with the costs for 2023-24.

These tables exclude the 2024-25 fixed NEM Fees cost of \$0.23 per week per customer – which averages about \$1-2/MWh depending on the level of consumption.

Table 4.15 Total of other costs (\$/MWh, nominal) – Energex – 2024-25

Cost category	2023-24	2024-25
NEM management fees	\$0.95	\$0.50
Ancillary services	\$0.47	\$0.21
Hedge and spot prudential costs	\$3.81	\$2.30
Reserve and Emergency Reserve Trader	\$0.04	\$0.00
June 2022 NEM events	\$0.90	\$0.00
Total	\$6.17	\$3.02

Note: The values for 2024-25 exclude the fixed NEM Fees cost of \$0.23 per week per customer – which averages about \$1-2/MWh depending on the level of consumption.
Source: ACIL Allen analysis

Table 4.16 Total of other costs (\$/MWh, nominal) – Ergon – 2024-25

Cost category	2023-24	2024-25
NEM management fees	\$0.95	\$0.50
Ancillary services	\$0.47	\$0.21
Hedge and spot prudential costs	\$2.24	\$1.71
Reserve and Emergency Reserve Trader	\$0.04	\$0.00
June 2022 NEM events	\$0.90	\$0.00
Total	\$4.61	\$2.43

Note: The values for 2024-25 exclude the fixed NEM Fees cost of \$0.23 per week per customer – which averages about \$1-2/MWh depending on the level of consumption.
Source: ACIL Allen analysis

4.5 Estimation of energy losses

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

The MLFs and DLFs used to estimate losses for this Determination are based on the draft 2024-25 DLFs (published 17 Apr 2024) and final 2024-25 MLFs (published 2 April 2024).

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2024-25 is shown in Table 4.17.

Table 4.17 Estimated transmission and distribution losses

	2023-24			2024-25		
	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	1.059	1.009	1.068	1.066	1.009	1.076
Energex – Controlled load tariff 9000 (31)	1.059	1.009	1.068	1.066	1.009	1.076
Energex – Controlled load tariff 9100 (33)	1.059	1.009	1.068	1.066	1.009	1.076
Energex - unmetered supply	1.059	1.009	1.068	1.066	1.009	1.076
Ergon Energy - CAC and ICC	1.033	0.971	1.003	1.034	0.979	1.012
Ergon Energy - SAC demand and street lighting	1.094	0.971	1.062	1.098	0.979	1.074
Energex – Small business primary load control tariff	1.059	1.009	1.068	1.066	1.009	1.076
Ergon – Large business primary and secondary load control tariffs	1.094	0.971	1.003	1.098	0.979	1.074

Source: ACIL Allen analysis of AEMO data

As described by AEMO¹⁹, 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:

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

¹⁹ See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

4.6 Summary of estimated energy costs

Drawing together the analyses and estimates from the previous sections of this report, ACIL Allen’s estimates of the 2024-25 total energy costs (TEC) for the Final Determination for each of the profiles are presented in Table 4.18.

This table excludes the 2024-25 fixed NEM Fees cost of \$0.23 per week per customer – which averages about \$1-2/MWh depending on the level of consumption

Table 4.18 Estimated TEC for 2024-25 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 2023-24 Final Determination (\$/MWh)	Change from 2023-24 Final Determination (%)
Energex – Residential and small business	\$162.95	\$15.02	\$3.02	1.076	\$13.76	\$194.75	(\$10.67)	-5.19%
Energex – Controlled load tariff 9000 (31)	\$96.08	\$15.02	\$3.02	1.076	\$8.67	\$122.79	(\$22.19)	-15.31%
Energex – Controlled load tariff 9100 (33)	\$103.67	\$15.02	\$3.02	1.076	\$9.25	\$130.96	(\$17.36)	-11.70%
Energex – unmetered supply	\$162.95	\$15.02	\$3.02	1.076	\$13.76	\$194.75	(\$10.67)	-5.19%
Ergon Energy – CAC and ICC	\$99.58	\$15.02	\$2.43	1.012	\$1.40	\$118.43	(\$2.67)	-2.21%
Ergon Energy - SAC demand and street lighting	\$114.53	\$15.02	\$2.43	1.074	\$9.77	\$141.75	(\$10.23)	-6.73%
Energex – Small business primary load control tariff	\$115.59	\$15.02	\$3.02	1.076	\$10.16	\$143.79	(\$12.41)	-7.94%
Ergon – Large business primary and secondary load control tariffs	\$103.67	\$15.02	\$2.43	1.074	\$8.96	\$130.08	(\$15.75)	-10.80%
Energex - Residential and small business - Time varying - Night	\$154.86	\$15.02	\$3.02	1.076	\$13.14	\$186.04	\$45.83	32.69%
Energex - Residential and small business - Time varying - Day	\$60.48	\$15.02	\$3.02	1.076	\$5.97	\$84.49	\$17.71	26.52%
Energex - Residential and small business - Time varying - Evening Peak	\$246.31	\$15.02	\$3.02	1.076	\$20.09	\$284.44	(\$74.70)	-20.80%

Note: The values for 2024-25 exclude the fixed NEM Fees cost of \$0.23 per week per customer – which averages about \$1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

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