AUSTRALIAN ENERGY MARKET COMMISSION

REVIEW

Final report

2024 RESIDENTIAL ELECTRICITY PRICE TRENDS METHODOLOGY REPORT

28 November 2024

Inquiries

Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: RPR0017

About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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1 Introduction

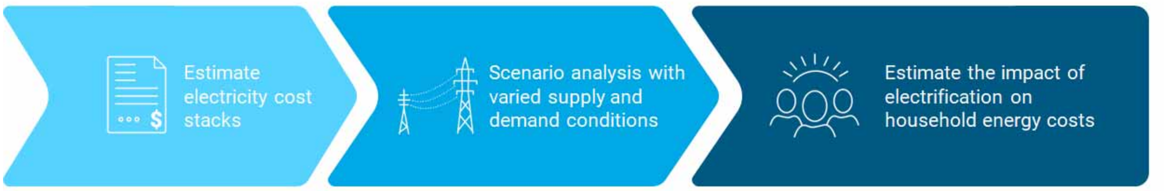
This methodology paper provides background information on how we developed the models to project residential electricity prices and household energy expenditure.

This paper should be read in conjunction with the Price Trends report. It provides the reader with background information on the assumptions, methodology and data sources necessary to understand the Price Trends project.

We used public information, developed assumptions where information was limited, and applied a variety of modelling approaches to:

- Estimate and project the costs of the components of electricity prices (i.e. to estimate a 'cost stack'), which comprises: wholesale, network, renewable/energy efficiency schemes and retail costs.[1]
- Conduct a series of scenarios to consider how changes to the supply of, and demand for, electricity would impact the outlook for residential electricity prices. These scenarios also tested the robustness of our models to the key assumptions we made.
- Consider how our electricity price projections will impact household energy expenditure (known as an 'energy wallet'). We modelled how electrification will impact household energy expenditure to understand the consumer impact of the energy transition.

Figure 1.1: Overall approach for Price Trends



We modelled the National Electricity Market (NEM), including Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia, and Tasmania. Western Australia and the Northern Territory are not part of our model.

Our models are based on the demand and supply projections from the market operator's latest Integrated System Plan (ISP); specifically we use the 2024 Final ISP's Step Change scenario as the basis for the buildout and retirement schedule, and for the growth in demand.

All results are presented in 2024-25 real dollars. Results of the report are generally expressed as average costs, either on a per unit basis or per household basis, except in the energy wallet section where results are expressed as household total expenditure on fuel (including petrol, gas and electricity).

The following sections of this paper consider, in turn:

- the methodology for each element of residential electricity cost stack, including wholesale, network, renewable/energy efficiency schemes and retail costs (sections 2 – 5);
- the methodology for estimating household energy expenditure with different degrees of electrification (section 6);

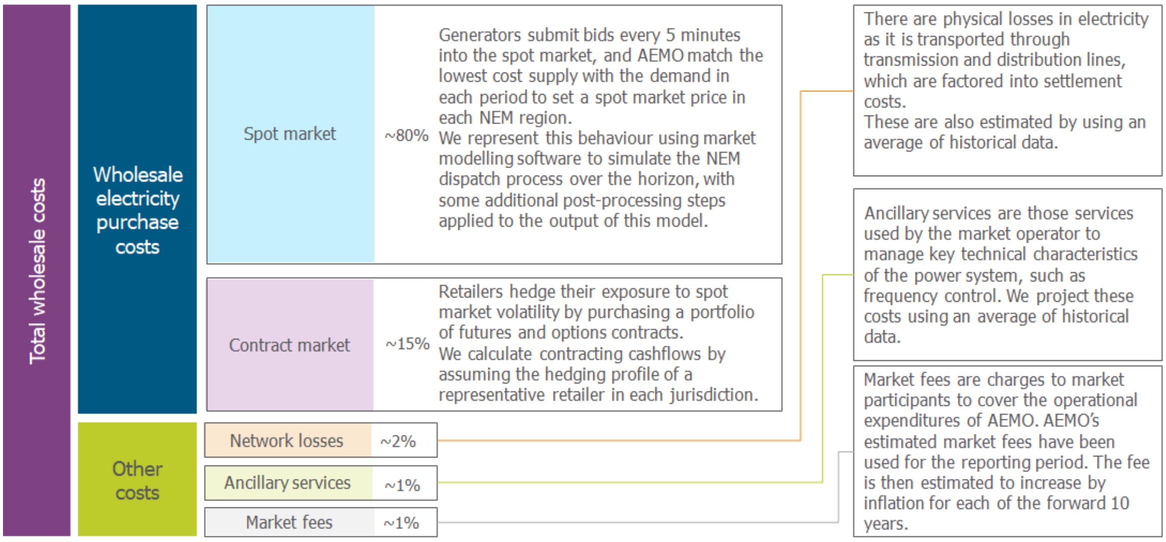
1 That is, our model projects cost stacks, rather than predict the individual tariffs faced consumers which can vary significantly.

- a summary of the key modelling assumptions and limitations (section 7); and
- the approach undertaken our scenario analysis (section 8).

2 Wholesale costs methodology

The wholesale cost component of electricity bills represents the costs associated with energy traded in the wholesale electricity markets, predominantly the electricity spot market, but also includes a small portion of costs from ancillary services (Figure 2). It makes up a large component of the bill and is generally the most variable cost on a year on year basis.

Figure 2.1: Components of wholesale costs



The wholesale electricity purchase costs are the dominant component of overall wholesale costs and are the most complicated to calculate. Currently, in the NEM, the price of wholesale electricity is determined every 5 minutes, for each region, based on an auction process. The price can vary from $-1,000/MWh to $17,500/MWh in each period,[2] based on current demand, and the bids offered by generators to meet this demand, which typically reflect each generators short-run marginal cost (SRMC). Specifically, generators of different types submit their proposed price and volume bids in 10 different bands to the Australian Energy Market Operator (AEMO) for the right to dispatch, and the market is settled every five minutes.

Figure 2.2: Our approach to projecting wholesale electricity purchase costs

Our modelling simulates how generators will supply electricity on the wholesale market for each period over the next 10 years – how much they will supply and at what price - based on projections for demand, as well as the entry and exit of generators based on AEMO's ISP.

2 Note that the price cap and price floor is indexed and scheduled to increase in each year from FY25-FY28. These changes are handled in our model by converting these price settings to real terms in line with our inflation forecast.

This component was estimated by first simulating dispatch outcomes in the future NEM through the linear programming software PLEXOS to forecast the spot price in each region of the NEM for every 30 minutes.[3] There are five regions: Queensland, NSW (comprising ACT), Victoria, South Australia and Tasmania.

Because wholesale prices can be extremely volatile, retailers generally hedge their exposure to wholesale prices by entering into financial contracts either in an exchange traded market such as the Australian Securities Exchange (ASX), or bilaterally with generators in an over-the-counter (OTC) market. Standard products include futures contracts which are effectively a contract-for-difference (otherwise known as a swap), cap contracts which set an upper limit on the price that a holder will pay for electricity, and options contracts which give holders the right (without the obligation) to enter into a futures contract. There are other types of contracts used in these markets such as peak contracts and Asian options, although these are less common. The flow on impact of retailers purchasing these electricity derivatives is to smooth out the wholesale costs passed on to electricity consumers.

To account for this, as a second step, we then estimated the impact that contracting would play in a retailer's overall electricity purchase cost. We projected these 'hedged' wholesale electricity costs over the horizon by:

- assuming a representative hedging portfolio
- using historical data to estimate contracting premiums and 'book build'[4] assumptions.

The following section outlines this methodology and assumptions in more detail.

2.1 Spot price methodology

The first step in calculating electricity purchase costs is to simulate the spot market in each NEM region over the horizon. In our modelling, we used a modified version of AEMO's 2024 Integrated System Plan (ISP) model, taking the Step Change scenario as the central case.

The ISP is developed by AEMO under the National Electricity Rules (NER) every two years using an integrated approach to energy market modelling and power system analysis. Its objective is to determine an Optimal Development Path (ODP) for the NEM that defines a schedule for building and retiring generation, storage and transmission assets in accordance with the published inputs, assumptions and scenarios (IASR)[5] and modelling methodology.[6] Along with the published reports that form the ISP, AEMO also publish a PLEXOS model, which represents the future grid up to 2050 and is used in conjunction with other models to determine the ODP. This model is a 'capacity expansion' model, and its objective is to determine a generation and interconnector buildout schedule, which serves as a starting point for our analysis.

The first step involved in modelling the spot market over the 10-year horizon is to convert AEMO's 'capacity expansion' model into a 'dispatch' model. There are two key steps to do this:

1. We ran the published 'capacity expansion' ISP model (also known as the long term, or LT model) to generate a buildout and retirement schedule for each generation and storage asset (this aligns with the buildout and retirement schedule published in the ISP document).

3 This is less granular than the 5-minute settlement period in the real world, however this is a compromise to ensure that the computational complexity and time to solve is not too prohibitive.

4 This refers to the schedule of purchases for a contract.

5 2023 Inputs, Assumptions and Scenarios Report published August 2023 and available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

6 ISP Methodology published June 2023 and available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology.

2. We converted the model into a 'dispatch' model by adding a Medium Term (MT) Schedule, Projected Assessment of System Adequacy (PASA) and Short Term (ST) Schedule objects into PLEXOS. When taken together, these objects changed the overall objective function of the model from determining the optimal build and retirement schedule to determining the most efficient dispatch outcome over the short and medium term. This modelling replicated the NEM dispatch engine by matching supply and demand every 30 minutes and estimating a spot price given the projected demand and projected supply mix.

There are some additional changes we made to our base ISP model for the purpose of Price Trends:

- We changed Eraring's retirement date from 2025 to 2027 in line with the latest NSW Government announcements and re-ran the capacity expansion model to produce a slightly different buildout schedule
- Detailed generator settings including minimum stable level and ramp rates were added to the dispatch model from AEMO's Electricity Statement of Opportunities (ESOO)[7] and IASR
- Bidding profiles were added to coal and gas units to produce dispatch outcomes that try to replicate the behaviour of those assets more appropriately than pure SRMC bidding (outlined in more detail in section 2.1.1)
- We added an additional variable operating and maintenance charge to batteries to temper the effect of perfect foresight (see section 2.1.1)
- We used the 2016 weather reference year as the basis for VRE output and electricity demand, rather than the original 'rolling reference year' approach used by AEMO (outlined in more detail in section 2.1.3)
- We projected per-unit wholesale costs in the ACT based on the NSW price, but with the load shape sourced from the ACT's Net System Load Profile (NSLP).

Following these changes, the model was run over the 10-year horizon to produce a spot price for every 30-minute interval in all jurisdictions, with demand at the 10% Probability of Exceedance (PoE) level, meaning that demand is expected to be greater than this only one in 10 years. We then performed two main post-processing steps:

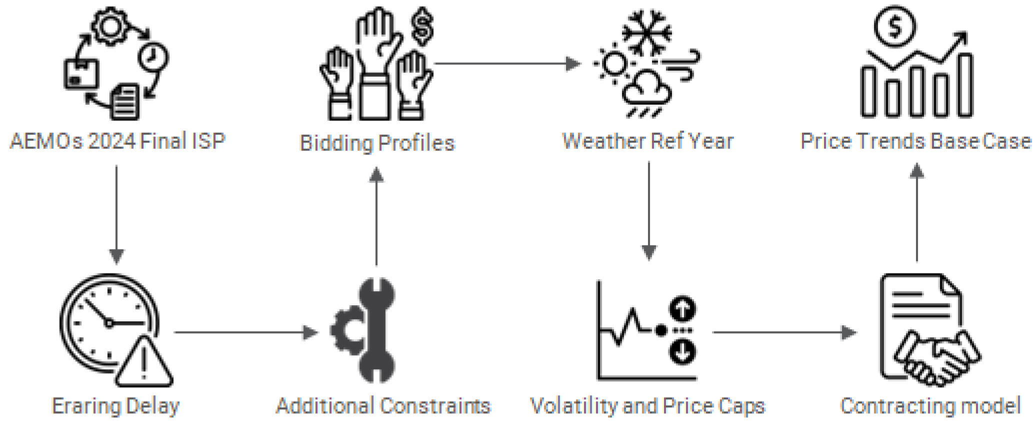
- An additional volatility adjustment was incorporated through post-processing to more fully reflect the impact of tight supply-demand conditions (outlined in more detail in section 2.1.2)
- Prices were adjusted according to the market price cap (MPC), cumulative price threshold (CPT) and administered price cap (APC) [8], where applicable
  - This mimics the real-world price interventions in the market to protect consumers from extremely high prices, and from periods of sustained high prices. Specifically, spot prices are capped at the MPC across all periods, and when the rolling total of the last 7 days of prices is above the CPT then spot prices are capped at lower level of the APC until cumulative prices drop below the CPT once again.
  - The final prices resulting from these steps are the wholesale electricity costs that were fed into the contracting model to produce a final hedged cost.

Selected steps are described in more detail below.

7 2023 Electricity Statement of Opportunities, published August 2023 and available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf.

8 These are price interventions in the market to protect consumers from extremely high prices, and from periods of sustained high prices; specifically, spot prices are capped at $17,500/MWh (the MPC) for each interval, and when the rolling total of the last 7 days of prices is above $1,573,700/MWh (the CPT) then spot prices are capped at a reduced level of $600/MWh (the MPC).

Figure 2.3: Key changes to ISP when modelling wholesale electricity prices



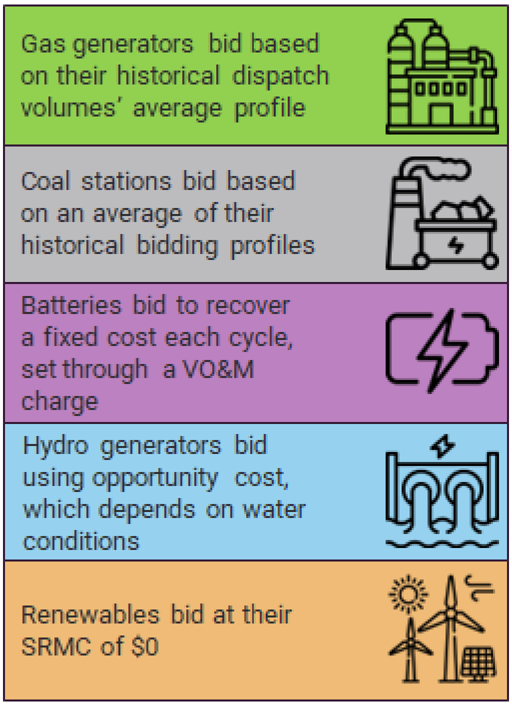
2.1.1 Bidding methodology

One of the key drivers of spot price outcomes in the electricity market and our modelling is the bidding behaviour of participants. In the spot market, generators submit bids in 10 price and quantity bands which reflect the price they are willing to receive for different quantities of energy produced. These bids differ by generator types as they typically consider factors such as the marginal cost of producing electricity and the long term cost of operating . On a marginal cost basis renewable technologies like solar are typically less expensive than thermal technologies like gas.

In the published ISP capacity expansion model[9], each generator bids all of its available capacity at its Short Run Marginal Cost (SRMC), reflecting the cost of fuel and other variable operating costs. However, in reality, generator offers reflect operating constraints, variable real-world conditions, and financial opportunities during market operation and not just their SRMC, resulting in material volatility and a significant impact on the wholesale spot price. To ensure our price forecasts reflect the real world as much as possible, we modify the bidding behaviour of selected technology types. The methodology used for each generator type is outlined graphically here, and explained in more detail below. Note that this bidding behaviour is static across the horizon.

9 Note that AEMO also use a time-sequential bidding behaviour model in their modelling for the ISP, as outlined in the ISP Methodology document (available at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en), however this model is not published.

Figure 2.4: Summary of bidding approach for each generation type



We assumed variable renewable energy generators bid at $0/MWh, unchanged from the published ISP model. Renewable energy generators are distinct from other generation sources as they have no fuel costs but their output varies in accordance with the available wind and solar resource, and are more likely to be contracted through instruments such as power purchase agreements (PPAs) which give them revenue certainty. For these reasons, they typically bid either: at $0/MWh; at the negative of green certificate prices such as large-scale generation certificates (LGCs); or at close to the market floor price (MFP). This bidding behaviour is also to ensure that they are lower in the bid stack and are able to be dispatched whenever they are able to generate. We chose to use the former method (bid in at $0/MWh) as these certificate prices are likely to fall toward $0 in the 2030s as renewable energy penetration continues to increase. The increasing penetration of renewable energy also means that bidding at deeply negative prices may no longer be sustainable from a cost recovery perspective.

Hydro generation was also bid into the model using their opportunity cost which is roughly between $8 - $20/MWh depending on water conditions. Hydro generators have more constraints on their generation than other generator types as they must consider their water storages, and the value of that water over time. In our model, as in other similar models, hydro bidding is optimised in PLEXOS by maximising the overall benefit to the system while respecting available capacity. Available capacity is affected by storage levels in both upper and lower pondages, all sources of inflow, either rainfall or pumped, and generator operating characteristics such as efficiency, utilisation rates at different storage levels, and minimum stable levels.

Batteries earn revenue in the wholesale spot market through arbitrage, where they generate at periods of high prices and charge at periods of low prices. They also earn revenue through other streams such as operating in the Frequency Control Ancillary Services (FCAS) markets to support grid frequency stability and being contracted as network support services. In our model, batteries do not have explicit bidding functions, but rather, were assumed to have a fixed cost of $40/MWh which acts as an arbitrage threshold between charge and discharge prices. The purpose of this is to ensure that batteries do not discharge when prices are $0/MWh, or cycle when the daily price spread is too low. Batteries and pumped hydro are difficult to model in PLEXOS (or any other optimisation software). The simulated behaviour of these assets will perfectly match price opportunities and power system demand because the models determine optimal prices over the next 24 hours. AEMO outlines several options in Appendix 4 of the 2024 ISP to try to address this problem. After several iterations of testing and calibration, we have chosen to add a fixed cost (modelled through a variable operational and maintenance charge (VO&M charge)).

Coal fired power stations were bid into our model based on historical bidding profiles. These generator types have a unique bidding behaviour due to high start-up and shutdown costs, wherein they often bid part of their capacity at negative prices in order to avoid the shutdown and restart costs. Our approach to developing these bidding functions is described below:

- Coal bids were based on the previous years of bidding data for each coal unit
- For each unit, 10 offer prices and offer quantities are set up, where each price and offer quantity is set to the average of the historical data
- This resulted in a profile that reflects typical bids and was unique to each unit, with a typical profile shown below:
  - ~60% of capacity bid at the market price floor
  - ~25% of capacity bid between $0/MWh and $100/MWh
  - ~5% of capacity bid between $100/MWh and $1000/MWh
  - ~10% of capacity bid between $1000/MWh and the market price cap
- To confirm the validity of this approach, capacity factors were compared with historical averages to ensure that dispatch outcomes in the model were reasonable.

Gas powered generators were bid into our model based on historical dispatch volumes at different price points. These generators have high short-run marginal costs, and often bid into the market to capture high price periods when there is low available capacity and/or high demand. The approach to modelling these assets is described below:

- For gas, historical bidding data was much more variable and time of day dependent and therefore was not appropriate for our modelling exercise. Instead, bid offer quantities were based on generator dispatch volumes at different price points
- Historical dispatch were analysed for each generator, with quantities assigned to a range of given price points based on the percentage of total capacity dispatched at each price point
- This alternative approach better reflected actual behaviour as it captured the impact of scarcity and intra-day dynamics
- The bid profile varies significantly between generators, though a typical profile is shown below:
  - ~30% of capacity bid around $100/MWh
  - ~60% of capacity bid between $100/MWh and $300/MWh
  - ~10% of capacity bid between $300/MWh and the market price cap
- To confirm the validity of this approach, capacity factors were compared with historical averages to ensure that dispatch outcomes in the model were reasonable.

The bidding methodology for gas powered generators is one of the more important factors influencing price outcomes, as gas is often the marginal unit which sets the price during critical periods across the year and in the day such as the evening peak. While we have calibrated these bids according to historical dispatch, it is difficult to represent the dynamic bidding behaviour that these generators display in the real world within a PLEXOS model. To get closer to real world price outcomes we post-process the results, we also added a 'price volatility adder', described below.

2.1.2 Price volatility adder

Modelling wholesale prices using the PLEXOS ISP model with the static bids as described above does not necessarily replicate the price volatility that occurs in the real world. There are a number of factors that explain this:

- PLEXOS is a perfect foresight model which means that there are no "unexpected" shocks to the system.
- The ISP model uses approximate constraints rather than the thousands of detailed constraints in the NEM – given the ISP produces a long term planning outlook. This reduces the variability of dispatch outcomes and prices.
- It is very difficult to program dynamic bidding strategies for generators that operate within portfolios, that are responsive to potential retail exposures of major gentailers, or to capture fixed costs during periods of supply scarcity.[10]
- It is impractical to separately identify and project all the sources of price volatility that interact with one another – for example, intra- and inter-regional transmission constraints, outages across the transmission networks, extreme weather, spare capacity (reserves), and unscheduled maintenance.

To approximate the impact of real-world volatility we considered the relationship between the regional reserve margin and regional prices. Typically a tight supply-demand balance has a reasonably good correlation with price volatility (for example, a tight supply-demand balance could result in a 'marginal' generator being able to increase the price closer to that typically offered by their more expensive competitors).

Specifically, we post-processed prices based on the supply-demand conditions in the model. That is we:

- analysed the <u>historical</u> relationship between supply-demand margin and price for each region in the NEM
  - This margin was calculated in megawatts (MW) as *Demand - (Available generation + Interconnector transfer capacity)* where:
    - Available generation refers to the total availability of all generators and batteries in the region as bid into the market
    - Interconnector transfer capacity refers to the MW available to flow into the region after taking into account import limits and current flow
  - From this margin, we then calculate the reserve margin as a percentage by dividing the reserve margin by demand
- From this analysis, we derived two distinct relationships: a linear relationship when reserve margins are greater than ~30%, and a much steeper linear relationship when the reserve margin is less than 30%

10 For a description of how generators capture fixed costs during periods of scarcity, see Yarrow and Decker (2014).

- We then calculated reserve levels in the model using an equivalent method, where the supply side includes the total capacity bid available from all generators and batteries, plus the additional capacity available on any interconnectors.
- Finally we increased the PLEXOS modelled prices by applying these two relationships to the predicted reserve margin from the model wherever the reserve margin is under 80%, over the 10-year outlook for each region in the NEM.

The below chart shows the historical relationship between reserve margin and log prices, with the linear model plotted in red. Note that the 'kink' in the red line is due to the connecting of the two different linear functions.

Figure 2.5: Relationship between reserve margin and prices

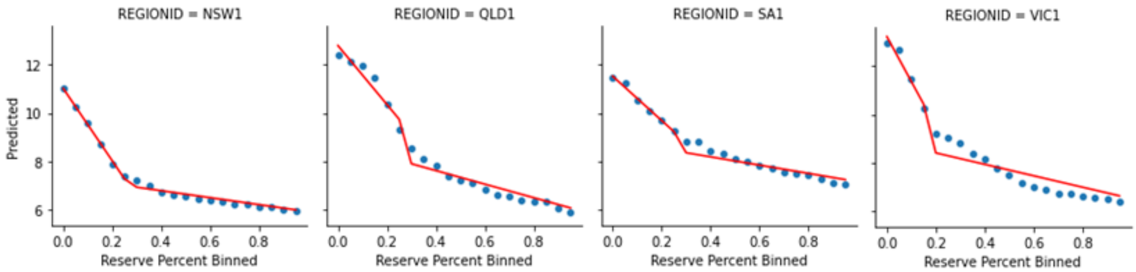


Figure 2.6 shows the impact on wholesale costs after adding in the price volatility uplift.

- On average, the volatility adjustment adds ~$3/MWh to the time-weighted prices, with the highest uplift occurring in South Australia, likely due to having a different generation mix than other regions
- Almost all of the uplift occurs during the evening peak, raising prices in this period by ~$15/MWh, leading to a more realistic time of day profile
- In terms of spot wholesale prices above $300, this increases their contribution to the average prices by up to 40% in some regions

Note that the Market Price Cap (MPC), Cumulative Price Threshold (CPT) and Administered Price Cap (APC) were also applied in post-processing to the spot price where relevant, which limits the extent to which the volatility uplift adjustment can increase prices.

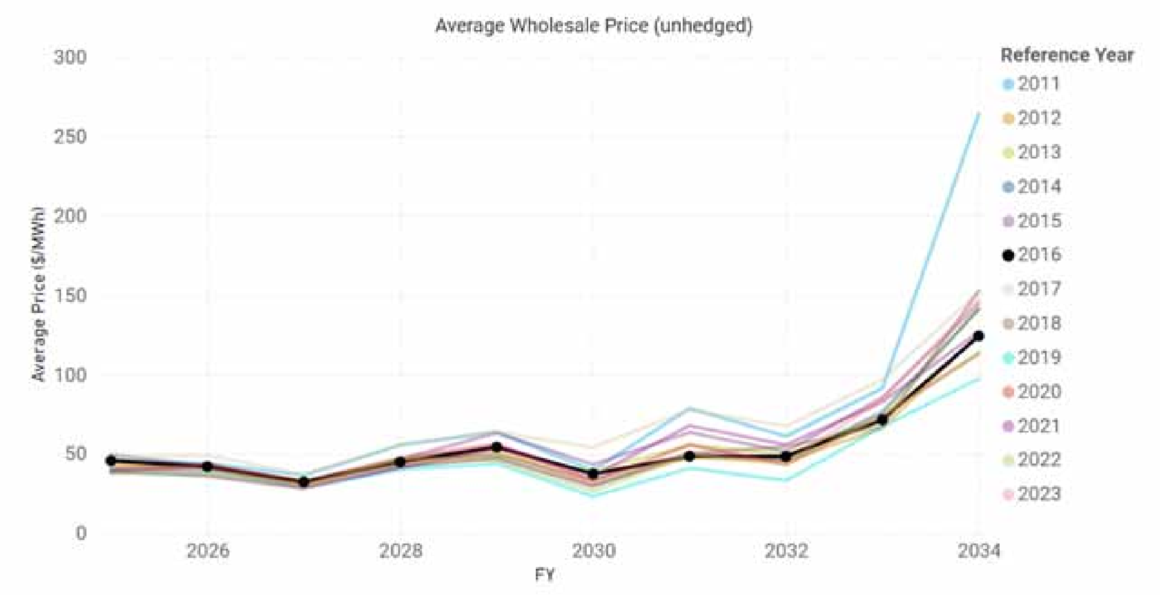
In summary, the volatility adder captures additional real-world volatility resulting from intra-day pricing dynamics. The longer-term price impacts of a tighter supply-demand balance are already captured by the forecast levels of demand and the generator buildout/retirement schedule as outlined by the ISP.

Figure 2.6: Change in modelled wholesale prices as a result of the volatility post-processing

2.1.3 Weather reference years

AEMO's 2024 Final ISP uses a "rolling reference years" approach that uses 13 historical weather years for demand, and wind, solar, and hydro performance to determine long term generation trends. However, for the purpose of Price Trends, a single reference year was used to represent weather patterns across the planning horizon. This approach minimises the effects of an arbitrary weather-related impact on *price*, given the future of weather output and volatility is largely unknown. The chart below shows the impact that weather can have on the spot price.

Figure 2.7: Range of modelled wholesale prices (unhedged) across weather reference years

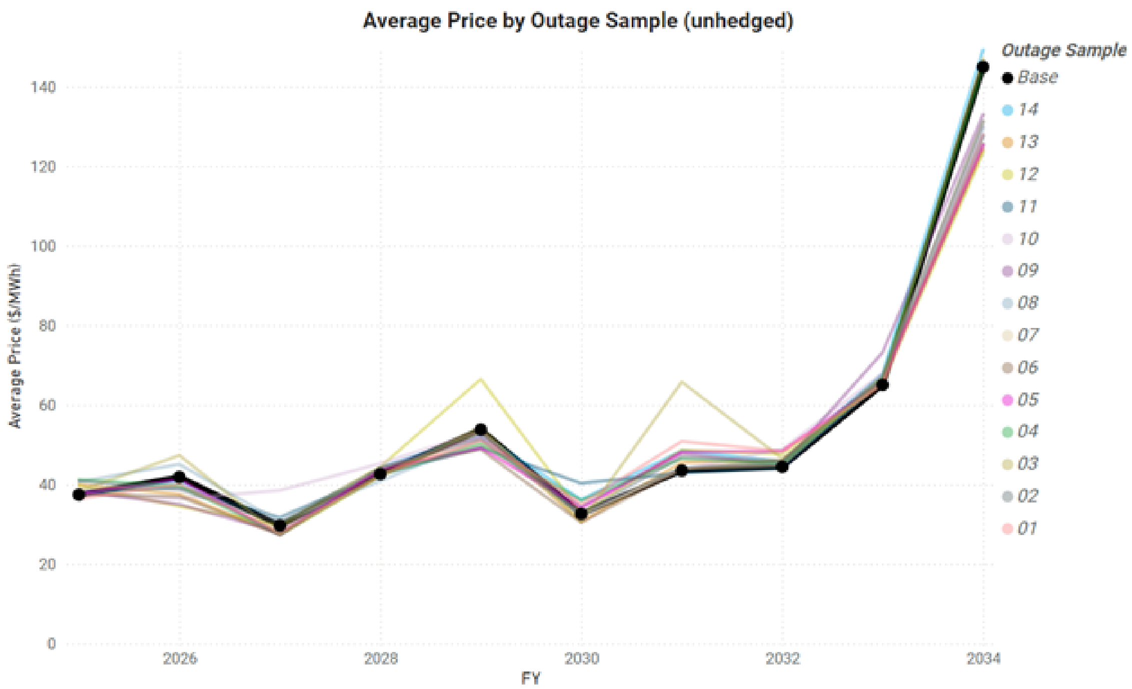


This chart shows the range of volatility adjusted wholesale prices when we ran the model under each of the 13 different weather reference years. We selected weather outputs from the 2016 reference year to determine the patterns throughout the planning horizon. This reference year was determined to be representative as it most frequently resulted in the median price across the outlook. A representative or median year was chosen rather than take an average of results across all years as the average smooths out prices across the day rather than allowing the price volatility seen in a single reference year.

2.1.4 Forced outages

Modelling generator and transmission behaviour in PLEXOS requires simulating an outage pattern. PLEXOS randomises forced outages and optimises maintenance outages for each generator and line. To ensure that an outlier or irregular sequence did not skew the results, 15 samples of outage patterns were simulated, based on the reference year 2016.

Figure 2.8: Range of modelled wholesale prices (unhedged) across 15 outage samples



As shown in Figure 2.8, changing the outage sample can have small-medium impacts on wholesale prices in a particular year.[11] To choose a representative sample, similar to the weather reference year analysis, the outage pattern that most frequently resulted in a median price was selected as the model's base case.

2.1.5 Modelling electricity demand in the Australian Capital Territory

Our PLEXOS model uses 12-nodes to represent major load centre locations across the NEM; four each in NSW and QLD, two in SA and a single node in both Victoria and Tasmania. The Australian Capital Territory (ACT) is not represented as a node, and as such we do not have an associated demand profile for this jurisdiction. Note that in market dispatch the ACT receives the same spot price as determined for the NSW regional reference node.

We estimated ACT demand in our wholesale model by taking the most recent Net System Load Profile (NSLP) for the ACT and applying this shape to a proportion of projected NSW demand. Specifically, we take the most recent 12 months of NSLP data from AEMO's website and scale this each day of the horizon such that the maximum energy and minimum energy in each day match 4% of the equivalent NSW demand. This proportion (4%) was calculated using historical yearly total load.

This approach allows us to produce a reasonable ACT demand profile. However, a limitation of this approach is that it assumes the load shape in the ACT will remain the same across the horizon. The NSLP is also an approximation of the actual shape of demand in the ACT for residential consumers. However, given the load in ACT is a small proportion of the total load, we

11 Note that, in practice, much of the year-to-year volatility from one-off outages is also smoothed out through the hedging of wholesale prices.

consider that this risk is not material to NEM-wide results and practically acceptable given the scope of this project.

2.2 Contracting methodology

2.2.1 Overview of methodology

To manage financial risks and gain more certainty over wholesale costs, retailers enter into various wholesale hedging contracts, including publicly traded products on the Australian Stock Exchange (ASX) and FEX Global (FEX) and also through bilateral agreements with counterparties.

We modelled this behaviour in our outlook through a contracting model that is overlaid onto the output of the market model. This better represents the costs that retailers face, and smooths out wholesale costs year on year. The methodology for contracting shares some similarities to that used by the AER in their Default Market Offer (DMO) report, however we have adopted materially different assumptions regarding contracting volumes, spot and strike prices, as our model is applied across a longer horizon (ten years rather than one). The main similarities and differences between the models are highlighted in the table below.

Table 2.1: Comparison between the AER's DMO and Price Trends

Component	AER's Default Market Offer	AEMC's Price Trends
Purpose	To set an electricity price that provides a 'safety net' to consumers, whilst also allowing retailers to recover costs	To provide an outlook of the residential electricity cost stack over the next decade to inform both policy-makers and consumers about the trends and main cost drivers
Time period	FY24/25 (1 year)	FY24/25 to FY33/34 (10 years)
Demand	• ESOO 2023 demand projections are used to represent system demand in wholesale price modelling • Net System Load Profiles (NSLPs) for each distribution area are used to represent retailer demand	The 2024 Final ISP step change demand projections are used for the shape and volume of demand both in the wholesale model, and as the retailer demand
Spot prices	Hourly prices forecast using ACIL Allen's proprietary wholesale energy market model	Hourly prices forecast using AEMCs Price Trends model which is based on the final 2024 ISP with some changes, including changes to bidding behaviour
Forward contract prices	ASX Energy contract price data	• For the first two years use ASX Energy contract price data • For the remainder of the horizon use the forecast spot prices with a contracting premium markup
Hedging strategy	• Build up book of contracts over 2-3 years • Include base, peak and cap contracts • Contract volumes are chosen based on minimising the 95th percentile	• Build up book of contracts over 2-3 years • Include base swaps, cap contracts and base options • Hedging strategy is based on a

Component	AER's Default Market Offer	AEMC's Price Trends
	simulated wholesale electricity costs	representative or typical profile, covering average expected PoE10 demand with base swaps and options, and covering up to expected maximum daily demand with cap contracts

We modelled the contracting behaviour in each jurisdiction by building up the hedging book of a typical or 'representative' retailer, purchasing a mixture of contracts to cover most of their load. There are a number of assumptions that go into building the portfolio of each representative retailer which are described in more detail throughout this section. Once each retailer has purchased a portfolio of contracts (we used base swaps, caps and options), we then modelled the final cashflows in each trading interval taking into account the spot price, the demand in the interval, the demand that has been contracted against, and the weighted price of those contracts. This is shown graphically below:

Figure 2.9: Approach to modelling cashflows for base swaps

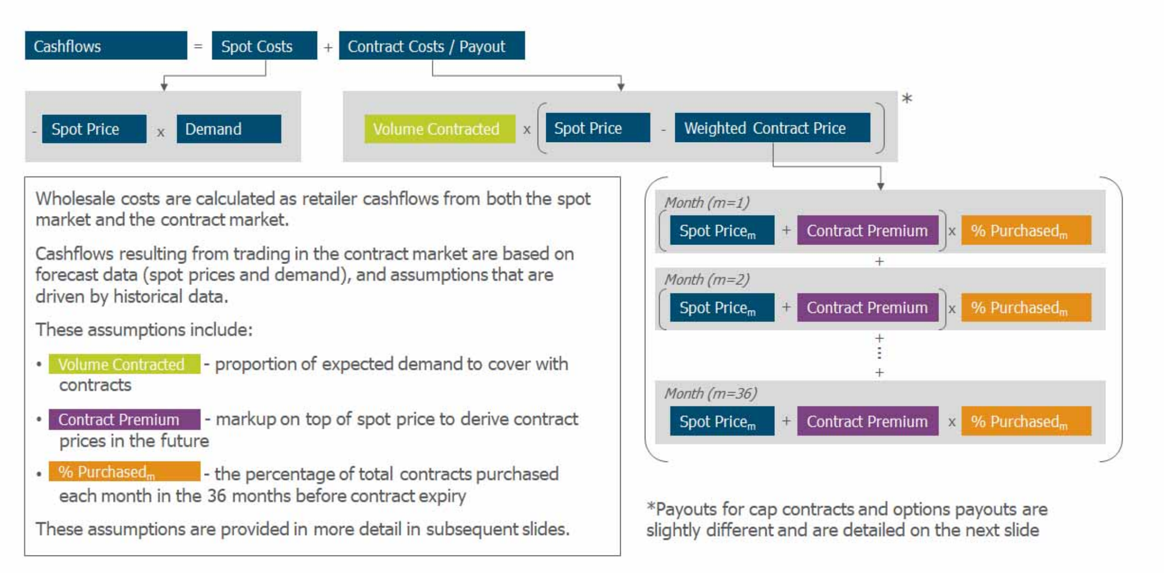


Figure 2.10: Approach to modelling cashflows for caps and options

The assumptions that sit behind this cashflow calculation are described separately below.

2.2.2 Contract premiums

The contract premiums have been calculated using historical spot prices (between Jan 2017 and July 2023, excluding 2022) and historical ASX-listed contract prices (base, peak and cap quarterly contracts between Q1 2017 and Q3 2024).

A hedging or contract premium was calculated as the difference between the volume weighted traded price of the contract and the average wholesale price over the exercise period.

These premiums were applied on top of the forecast spot price, and were simulated to be purchased up to 36 months ahead of contract expiry according to the book build assumptions described below. Note that the same premium was used for each period as it was calculated using the trade volume weighted average ex-post difference spot prices and contract prices. Our modelling is therefore robust if premiums may be higher when the contract is purchased further away from expiry (that is, if there is a term premium).

The values for premiums used in the model are shown in the table below. Note that:

- Liquidity in South Australia is lower than other jurisdictions, as has historically been the case, leading to higher premiums than other states for base contracts.
- Option premiums are applied on top of the calculated base contract prices and added to the option purchase price
- ACT and Tasmania have a very different contracting environment than other jurisdictions; however, we make simplifying assumptions that their retailer behaviour is based on NSW and Victoria respectively:
  - Contract prices and retailer behaviour in the ACT are based on NSW. As the ACT does not have a separate spot or contract market, it is considered as part of NSW
  - Tasmania is a unique jurisdiction in the NEM as it is reliant on hydrological inflows for most of its generation power, and there is a single company (Hydro Tasmania) which owns almost all of its generation and interconnection assets. Wholesale contracts in Tasmania are regulated by the Office of the Tasmanian Economic Regulator (OTTER) which sets a

maximum price for contracts and ensures that they are broadly consistent with products offered in the rest of the NEM

- Wholesale contracts in Tasmania typically follow Victoria as these regions are interconnected and spot prices are historically very similar
- Based on these reasons we base Tasmania on Victoria in the contracting model.

Table 2.2: Ex-post contracting premiums used in the contract model

State	Base Premium	Cap Premium	Option Premium	Option Purchase Price
NSW & ACT	$13.3	$3.9	6.5%	$6.9
QLD	$7.1	$2.5	15.3%	$4.7
SA	$23.7	$3.1	-	-
VIC & TAS	$10.9	$4.7	6.2%	$5.0

2.2.3 Book build assumptions

Retailers purchase contracts to cover their load over time, rather than purchasing them all at once just before the contract period. This is both for cashflow reasons and to reduce risks associated with price fluctuations.

The below chart shows the percentage of total contracting volumes purchased each month in the lead-up to the expiry of the contract for futures and caps in our model.

These percentages were calculated by fitting a polynomial curve against historical data (2017 Q1 to 2024 Q3). The percentage purchased each month was calculated by dividing the total traded volumes for a product each month in the 36 months before expiry by the total volume traded for the product.

Figure 2.11: Book building curves used in the contracting model

Contract volume / hedging assumptions

Retailers typically purchase a range of contracts to cover different proportions of their expected load based on their own forecasts of demand and price and their appetite for risk. To estimate this, we assumed a typical or representative retailer who contracts to cover all of their expected load at the 10% probability of exceedance (PoE10) level (where demand is expected to exceed this with a 10% chance of occurring in any given year):

- Base swaps and options were modelled to cover the average expected PoE10 load in the quarter
- The split between options and swaps was based on analysis of recent volumes traded in each contract type, which showed that options represent 50-60% of total trades between base swaps and options
- Cap contracts were modelled to cover the difference between the average daily maximum PoE10 load and the average PoE10 load over the quarter
- No peak contracts were modelled, as liquidity in these contracts have been extremely low in the last 3 years

These contracting volumes are an estimate based upon the research outlined below:

- The analysis and indicative hedging strategy described by the 2024 paper 'Derivatives and hedging practices in the Australian National Electricity Market' published in Energy Policy
- AEMC data analysis of publicly traded contracts on the ASX
- AEMC qualitative desktop analysis of hedging strategies in the NEM

We note however that these contracting volumes are only a representative estimate based on the information we have available, and in reality retailers may use different strategies including vertically integrating generation and retailing to manage price risk.

This strategy is described graphically in the two figures below. The first figure provides an indicative hedging strategy from the paper 'Derivatives and hedging practices in the Australian National Electricity Market'[12], while the second figure shows an example of the hedged volumes in our model for a single region and quarter.

Figure 2.12: Representative hedging profile

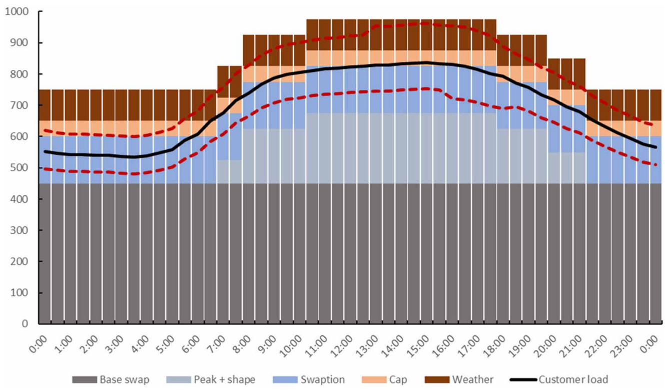


Figure 2.12 shows a simplified contracting profile for a retailer based on the responses of survey participants, as documented in the above paper. This shows retailers using a combination of swaps, options, caps and more complex weather-based derivatives to manage risk. Note that the black solid line represents the central customer load profile, and the red dotted lines represent additional flexible load.

12 Published by Jonty Flottmann, Phillip Wild and Neda Tedorova in July 2023, available at https://doi.org/10.1016/j.enpol.2024.114114.

Figure 2.13: Example of hedging profile used in the model (NSW Q3 2028)

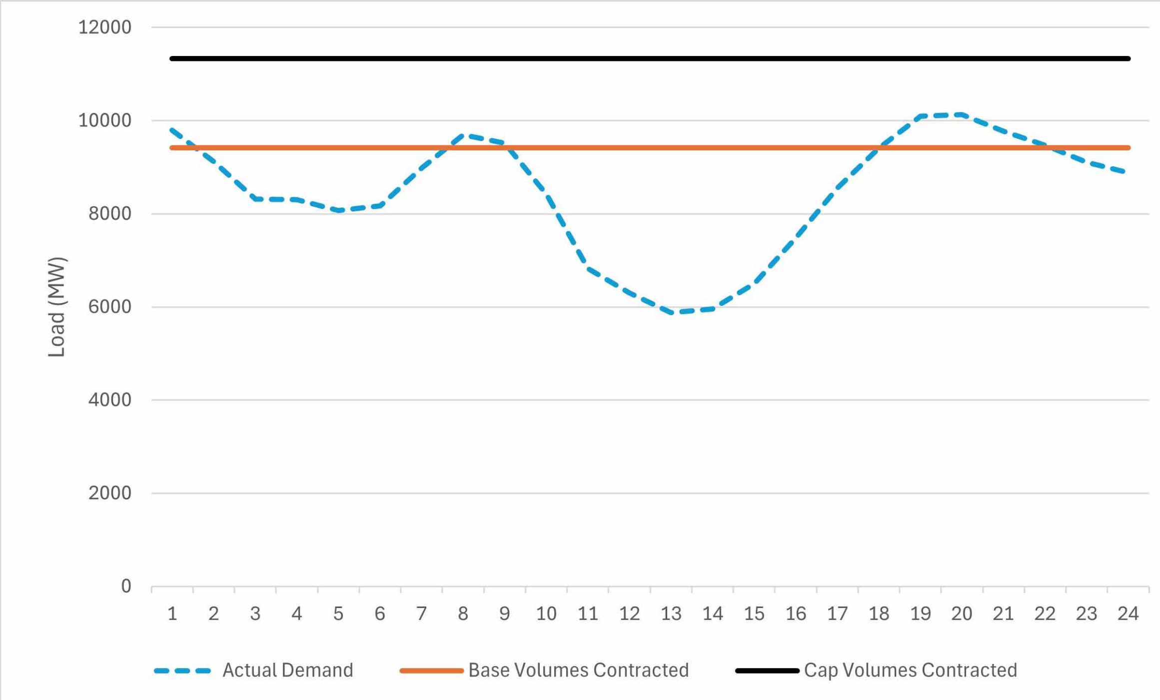


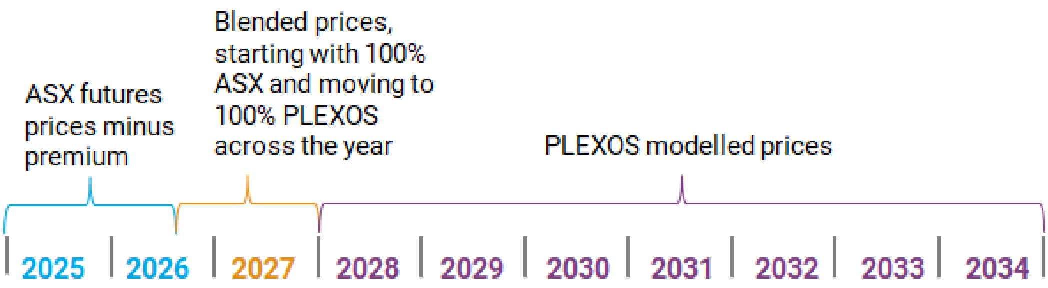
Figure 2.13 shows an example of how load is hedged in our contracting model, where the orange line represents the level of contracting for baseload contracts (purchased through a combination of swaps and options), and the difference between the orange line and the black line represents the volumes of cap contracts purchased.

2.2.4 Overlaying short-term market expectations

Market expectations for the first 2-3 years of the price outlook are also available to us, based on the traded prices of ASX forward contracts. These contracts are publicly traded and the prices listed on the exchanges indicate the value that industry currently places on the cover that these instruments provide. Put another way, the prices at which these forward contracts trade should reflect 'real' market expectations of future wholesale prices (plus the contract premium). As a final step, we therefore overrode the PLEXOS-produced spot prices over the first 36 months of the horizon with these market expectations. Specifically, we used the average base swap contract price from the ASX[13] as the spot price for the first 24 months, and then slowly transitioned to using PLEXOS modelled prices over the following 12 months using a linear function that weighted the PLEXOS prices incrementally from 0% to 100% across this period.

13 Note that the estimated contracting premium is removed from forward contracts, since these contracts are priced slightly above the expected future spot prices.

Figure 2.14: Where spot prices come from in the wholesale model



2.3 Other costs

At outlined in the beginning of section 2, we also estimated costs related to Ancillary services, Network losses, and Market fees. These are a small share of residential electricity costs, and therefore we have adopted simpler modelling techniques.

The costs we captured in the model are:

- Frequency Control Ancillary Services (FCAS)
- Network losses, and
- AEMO revenue requirements (market fees)

Ancillary services are those services used by the market operator to manage key technical characteristics of the power system, such as frequency control. We projected these costs simply by taking the average of the previous three years of costs and applying this as a constant value across the horizon. The three-year average is taken from AEMOs Ancillary Services Payments and Recovery workbooks[14], and we calculated costs per MWh by dividing the ancillary services revenue by customer demand.

Network losses are the physical losses in electricity as it is transported through transmission and distribution lines and are factored into settlement costs. These costs were also calculated in each year of the horizon by using a three-year moving average of historical transmission and distribution loss factors. The historical data used in this calculation was taken from AEMOs loss factors and regional boundaries workbooks.[15]

Market fees are charges to market participants to cover the operational expenditures of AEMO. These fees were estimated across the forecast horizon in our model by taking AEMO's NEM revenue requirement for FY25 and escalating it by our inflation forecast for each following year.

We did not include costs for the Reliability and emergency reserve trader (RERT), System restart ancillary service (SRAS) and network support and control ancillary services (NSCAS). This is

14 https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/ancillary-services-data/ancillary-services-payments-and-recovery

15 https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries

because these costs form a very small share of costs and do not materially impact bills on a year-to-year basis.[16] However, they are quite volatile year-to-year and are therefore difficult to project reliably.

16 For more information about the typical range of costs for these services, please see AEMC, FY2023 Annual Market Performance Review Final Report, June 2024, Section 3.3. Available at: https://www.aemc.gov.au/sites/default/files/2024-06/FY2023%20AMPR%20final%20report.pdf.

3 Network costs methodology

This chapter outlines how we projected network costs, which are the largest component of electricity costs.

3.1 Overview of network costs

Network businesses in the NEM comprise transmission network service providers (TNSPs) and distribution network service providers (DNSPs). There are five state-based TNSPs servicing each of the states in the NEM, with cross-border interconnectors linking the grid at jurisdictional borders. TNSPs serve as the link between generators and the distribution networks that supply electricity to residential customers, as well as small- and medium-business customers. The network cost model uses as much publicly available information as possible to project costs for distribution and transmission networks for 10 years.

Network costs are regulated by the AER who make determinations, based on proposals from each network, that set how much revenue each network business can recover from consumers. Our network cost model estimates an annual revenue requirement for each of the distribution and transmission businesses. We use information from AER determinations and then model the networks included in Table 3.1.

Table 3.1: Modelled Distribution Networks, Transmission Networks and Interconnectors

DNSP	Jurisdiction		TNSP or interconnector	Jurisdiction
Ausgrid	NSW		Ausgrid	NSW
AusNet	VIC		AusNet	VIC
CitiPower	VIC		ElectraNet	SA
Endeavour Energy	NSW		Powerlink	QLD
Energex	QLD		TasNetworks	TAS
Ergon Energy	QLD		Transgrid	NSW
Essential Energy	NSW		Murraylink	SA/VIC
EvoEnergy	ACT		Directlink	NSW
Jemena	VIC		Marinus Link	TAS/VIC
PowerCor	VIC			
SAPN	SA			
TasNetworks	TAS			
United Energy	VIC			

This includes modelling costs for three regulated interconnectors: Murraylink, Directlink and Marinus Link. Interconnector cost allocation is based on the proportion of physical asset located in each region. The allocation for Murraylink and Directlink has been set at:

- Murraylink: 45% to South Australia and 55% to Victoria[17]
- Directlink: 100% to New South Wales[18]

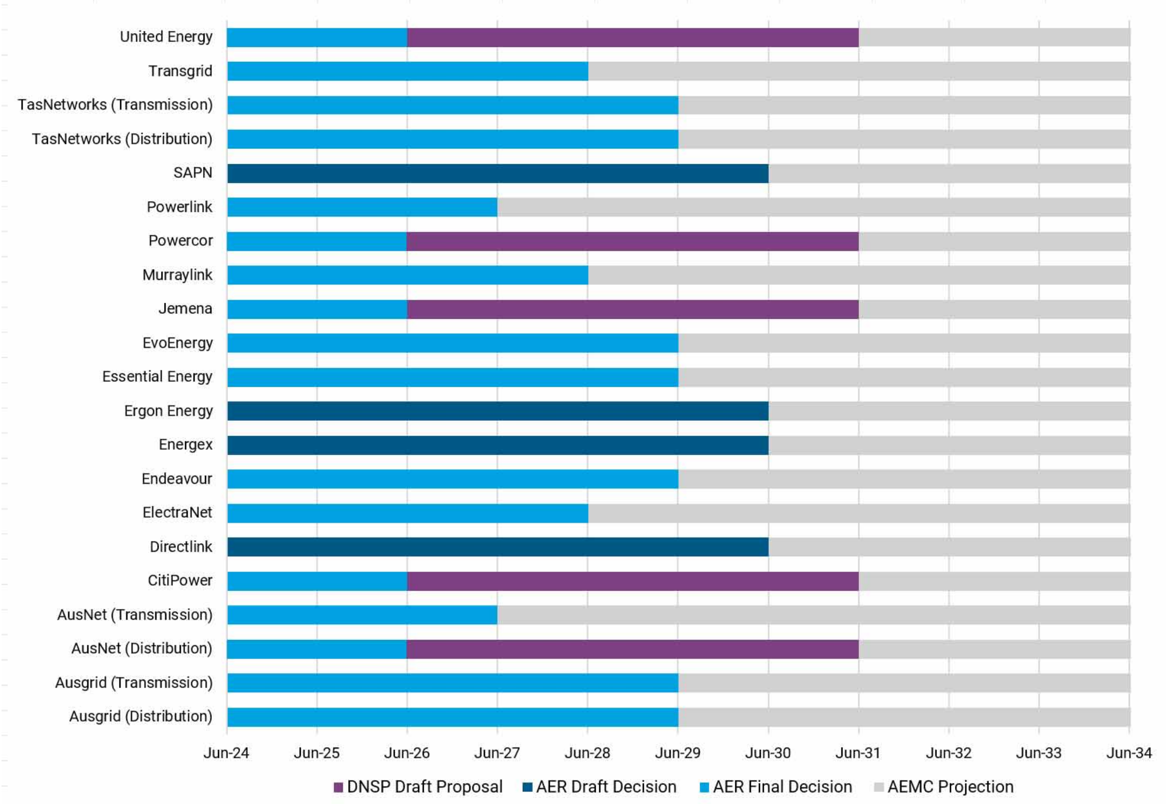
17 AER (2017), Draft Decision - Murraylink transmission determination 2018 to 2023, Attachment 1 – Maximum allowed revenue, September 2017, p.18.
18 Directlink (2014), Pricing Methodology , May 2014, p. 2.

The cost allocation arrangements for Marinus Link are unknown, and thus we assumed they are allocated 50% to Tasmania and 50% to Victoria. We maintained these proportions over the forecast period. We recognise that the actual allocation may be different in practice, however, we consider this 50:50 split at the current time to be a reasonable estimate.

To summarise our approach, we calculated annual revenue requirements using the building block method adopted by the AER.[19]

- If data was available for an individual network, as part of a current or upcoming AER determination, we used that data from each network's post-tax revenue model (PTRM)[20], adjusting for inflation in each year to ensure costs are calculated consistently. There is a substantial difference in the amount of data available for each network due to differing regulatory cycles. Figure 3.1 below shows the period in which we have AER data for each TNSP and DNSP.
- For the years where we do not have AER revenue requirements from the PTRM, we used different data sources for transmission and distribution networks to approximate the AER revenue requirements and project costs. The key assumptions we have made are explained in the following sections.

Figure 3.1: Network data availability over the 10-year outlook



19 More detail on the AER's approach is contained in its State of the Energy Market reports, with the 2024 report available here: [to include when released]

20 The PTRM is a financial model used by the AER to determine the revenue allowance for regulated energy network service providers. The AER updates the PTRM for each regulated network service provider every five years as part of the regulatory determination process.

3.2 Transmission network costs

Transmission network costs were estimated using a 'bottom-up' approach.

We calculated transmission network service provider (TNSP) and interconnector annual revenue requirements for each 'cost building block' in each forecast period. These costs were then aggregated by state and adjusted for modified load export charges (MLEC).[21] Finally, we assigned a portion of this adjusted revenue requirement to residential customers.

3.2.1 Overview of TNSP and interconnector cost building blocks

Estimates for TNSP and interconnector annual revenue requirements in each forecast period were based on a building block model for each transmission network. Broadly, this involved:

- Calculating the real regulatory asset base (RAB), by estimating assumed real capital expenditure (capex) and depreciation
- Calculating each element of the building block revenue, including return on capital, return of capital, operating expenditure (opex), and net tax allowance.

3.2.2 Estimating real regulatory asset base

The real regulatory asset base was estimated in each forecast period by adding new capital expenditure less depreciation to the opening RAB balance.

TNSP and interconnector new capital expenditure was estimated across three standard categories: augmentation expenditure (augex), replacement expenditure (repex) and other capex.

To estimate augex, we adopted a 'bottom up' approach that reflects what we consider to be credible forthcoming augex investments. To do so, we used:

- The most recent determination or proposal for each TNSP and interconnector, which captures augex included in their respective base allowances and costs related to contingent projects
- Network planning documents, including the ISP, Transmission Annual Planning Reports (TAPRs) and Victorian Annual Planning Reports (VAPRs). The ISP includes actionable and future augex projects, which are both captured in our forecasts.

Where these sources are conflicting, we adopted the network build indicated in the 2024 ISP Step Change Scenario.

To estimate TNSP and interconnector repex, we used repex values from the most recent determination or proposal where available. Where this is not available, future repex is projected to be the average annual repex requirement of each TNSP or interconnector for its most recent regulatory period. This means that repex is constant outside of the current regulatory period in real terms.

Finally, other capex requirements for TNSPs and interconnectors are estimated in the same way as repex. That is, data is taken from the most recent determination or proposal where possible, and where not, a historical average is used and held constant in real terms.

To estimate regulatory depreciation, we considered two types of network assets: those that exist in the PTRM for each TNSP and those that are constructed in the period following the PTRM. For the former, the depreciation profiles provided by the PTRM – this is the depreciation on the existing RAB – are available for the 10-year outlook. For the latter, we assumed that new TNSP

21 Modified load export charges recover the costs associated with the use of assets considered to support inter-regional flows to neighboring regions, and our approach in relation to MLEC is further discussed below.

assets have a useful life of 32 years and apply straight-line depreciation.[22] This is based on a weighted average of asset life, by value of asset, from available PTRM data.

The closing RAB balance is then calculated for each TNSP and interconnector using the depreciation and capex assumptions noted above.

3.2.3 Estimating building blocks

There are four key elements we estimated to project TNSP and interconnector nominal annual revenue requirements, before converting these back to real $2024-25 dollars. These are:

- Return on capital and debt
- Return of capital (depreciation)
- Opex
- Net tax allowance

A weighted average cost of capital is used to calculate the return on capital

To determine the return on capital and debt, the AER applies a Weighted Average Cost of Capital (WACC) to the cost of the assets that networks recover from customers. Because the AER adopts a real building block approach, the AER estimates a weighted average of the cost of debt and the cost of equity, and deflates this by an estimate of expected inflation.

We based our estimates based on the standard approach adopted by the AER, by projecting these variables (see Table 3.2 below). Our projected rate of return therefore does not assume any impact of concessional financing, as outlined in the limitations table in Chapter 7 below. For other 'WACC' variables – e.g. the value of imputation credits – we adopted the parameters in the AER's most recently published WACC methodology.[23]

Table 3.2: Key WACC inputs adopted in Price Trends modelling

Parameter	Value For all years of the outlook unless noted
Nominal pre-tax cost of debt	4.65% (2024-25)
Nominal post-tax return on equity	7.91% (2024-25)
Risk free rate	4.19% (2024-25)
Gearing	60%
Corporate tax rate	30%
Gamma (value of imputation credits)	0.57

22 Any 'new' capital expenditure by Murraylink and Directlink is assumed to have a shorter weighted-average useful live, of 21 years, compared to other TNSP assets. These projected capex requirements are small. We adopted a shorter asset live assumption because these interconnectors are existing assets, and any new capital expenditure is more likely to be for shorter lived assets – e.g. replacing IT assets.

23 AER, Rate of Return Instrument: Explanatory Statement,available at: http://www.aer.gov.au/system/files/AER%20-%20Rate%20of%20Return%20Instrument%20-%20Explanatory%20Statement%20-%2024%20February%202023_1.pdf

The key assumption we made, for simplicity, is that each network faces the same rate of return over the 10-year outlook. For the cost of debt and equity, we use the average of the forecast WACC values adopted in the AER's most recently released revenue determinations.

- The return on debt set by the AER is a 10-year trailing average and is updated annually. Under the AER's framework, individual networks may nominate their own dates for measuring the return on debt in each year. This difference is small over a 10-year outlook. While each network has a slightly different allowed return on debt in a given year, over time, the differences should largely average out.
- In contrast, the return on equity is set at the beginning of each 5-year determination period, and maintained until the following determination. In practice, the Victorian DNSPs have a different return on equity for the first two years of the outlook, as their regulatory periods have not yet ended.[24] This has a small, but temporary, impact on our outlook.
- Our estimate of expected inflation is based on the AER's methodology. Specifically, we estimated future inflation based on the RBA's forecasts from the most recent Statement of Monetary Policy, for Years 1 and 2 of the outlook. We then applied a linear glide-path from the RBA's forecasts of inflation for years 1 and 2 to the mid-point of the inflation target band (2.5 per cent) in year 5. We adopted the midpoint of the target (2.5 per cent) thereafter.

The return of capital (depreciation) was estimated as described in the previous section.

Estimate opex using the historical relationship between RAB and opex growth

TNSP and interconnector opex was calculated using the ratio of RAB to opex growth, when data is unavailable from the PTRM. We make this simplifying assumption because opex is partially driven by the size of the network. Hence, we use the RAB to proxy for scale factors in operating expenditure. We observed that across both TNSPs and DNSPs, a 1% increase in RAB is correlated with approximately a 0.72% increase in OPEX. Thus, for forecast years where PTRM data is not available, the model calculated the change of opex as a function of RAB growth.

Apply a diminishing value method to calculate a tax allowance

To estimate the net tax allowance for each TNSP and interconnector, it is necessary to first calculate tax depreciation. Similarly to regulatory depreciation, tax depreciation for existing assets in the RAB can be projected for the entire 10 year horizon based on the most recent PTRM. For network assets constructed in the period following the PTRM, we calculated tax depreciation using the diminishing value method to be consistent with the AER's PTRM. Finally, we assumed that new TNSP assets have the same tax standard life as useful life – 32 years for TNSPs and Marinus Link, and 21 years for Murraylink and Directlink.

Finally, we calculated the tax payable less the value of imputation credits to estimate the net tax allowance in each forecast period.

3.2.4 Aggregating annual revenue requirements and adjusting for inter-regional costs

Modified Load Export Charges (MLEC) reflect the principle that neighbouring regions that use another's network should contribute to the costs of providing and operating that network. MLEC applies to both transmission networks and interconnectors, however the latter appoints a coordinating network service provider to handle these payments.

24 Our estimate of the return on equity is relatively high compared to previous estimates from recent AER determinations. This is because the return on equity is calculated as a spread above the risk free rate, and the risk free rate is currently high compared to recent years.

The allocation of these costs between regions is based on inter-regional energy flows. In the model, we:

- Set the MLEC costs for each network as a percentage of network required revenue, on the basis of the 2024-25 published MLEC. This percentage was then applied to TNSP required revenue in all forecast periods to calculate the 'gross' MLEC for each network.
- Calculated the net MLEC payable for each transmission network, and subsequently each region

The net amounts were then aggregated with the relevant TNSP and interconnector required revenues (as estimated previously) to produce a regional estimate of transmission network costs.

As outlined in Chapter 7, our modelling excludes settlement residue auction proceeds and other interregional settlement residues that accrue due to trade across regions in the NEM. Trade supports the flow of energy from regions with low wholesale prices to regions with high wholesale prices. Some of the benefits of this trade are passed through to consumers through settlement residues. Therefore, all else equal, our price outlook would represent an over-estimate of the costs that households would face, because we are only accounting for some of the benefits of trade across regions in the NEM.[25]

We were unable to reliably project these residues forward because doing so would require being able to map how projected changes in regional trade (both the expected volume of trade and the degree of price separation) would affect the outcomes of settlement residue auctions. We therefore adopted a conservative assumption and set these flows to zero in the model.

3.2.5 Assigning transmission revenue requirements to residential customers

Not all transmission network costs are subsequently allocated to distribution network service providers (DNSPs), as some customers are directly connected to the transmission network. Specifically, DNSPs recover payments made by DNSPs to TNSPs through Designated Pricing Proposal Charges (DPPC). These charges are included as part of DNSP's annual pricing proposals (APPs). Based on the most recent DNSP APPs, we calculated the proportion of DPPC revenue from each DNSP to total regional transmission network costs. This proportion is held constant through the remainder of the forecast period.

As a separate but related variable, we also forecast that a constant proportion of the DNSP revenue requirement is recovered from residential customers, based on the most recent Annual SCS Pricing Models.[26] This proportion was held constant through the remainder of the forecast period. The proportions are shown in Table 3.3 below. Finally, we multiplied the DPPC in each period by the proportion of revenue to be recovered from residential customers to calculate the transmission network costs borne by residential customers.

Table 3.3: Proportion of DNSP required revenue recovered from residential customers

DNSP	Proportion of total revenue
Ausgrid	48%
AusNet	57%
CitiPower	31%

25 For more detail on how settlement residues affect electricity costs, see CEPA, Settlements Residue Auction and Modified Load Export Cost processes, a report for the AEMC, May 2024, available at: https://www.aemc.gov.au/sites/default/files/2024-06/cepa_report_-_sra_and_mlec.pdf

26 For an example of the annual SCS pricing models submitted to the AER, see https://www.aer.gov.au/documents/ausgrid-2024-25-annual-scs-pricing-model-15-may-2024

DNSP	Proportion of total revenue
Endeavour Energy	59%
Energex	62%
Ergon Energy	50%
Essential Energy	57%
Evoenergy	47%
Jemena	50%
Powercor	50%
SAPN	54%
TasNetworks	65%
United Energy	53%

3.3 Distribution network costs

Similar to TNSPs, distribution network costs were estimated by calculating DNSP annual revenue requirements for each year in the 10-year outlook. A portion of this revenue requirement was then assigned to residential customers, and aggregated by state.

3.3.1 Overview of DNSP revenue requirements

Estimates for DNSP annual revenue requirements in each forecast period were based on the same cost building block approach as for TNSPs. The key difference is that we adopted a more 'top-down' approach for estimating DNSP capital expenditure.

3.3.2 Estimating real regulatory asset base

The real regulatory asset base was estimated in each forecast period by adding new capital expenditure less depreciation to the opening RAB balance.

DNSP capex is taken from the PTRM where available. In outlook years where capex was not available from the PTRM, we calculated capex as a percentage of the opening RAB for that year. These percentages are included in Table 3.4 and were based on historical averages from each DNSP's PTRM. The exception to this is for the Victorian DNSPs (AusNet, Citipower, Powercor, United Energy, and Jemena). For these DNSPs, we have used capex figures sourced from their respective draft revenue proposals between 2026-2031. Following 2031, we held capex constant, in real terms, at an amount consistent with the figures between 2026-2031.

Table 3.4: DNSP capex to RAB ratios

DNSP	Capex as a % of RAB
Ausgrid	4%
Endeavour Energy	5%
Energex	3%
Ergon Energy	4%
Essential Energy	6%
Evoenergy	6%
SAPN	7%

DNSP	Capex as a % of RAB
TasNetworks	7%

Regulatory depreciation for DNSPs was estimated following the same methodology as for TNSPs and interconnectors, with the exception that we assumed that DNSP assets have a useful life of 40 years. This is based on a weighted average of asset life by value of the asset from available PTRM data.

The closing RAB balance was then calculated for each DNSP using the depreciation and capex assumptions noted above.

3.3.3 Estimating annual revenue requirements

To estimate the building block annual revenue requirement for DNSPs we followed the same methodology as TNSPs and interconnectors. That is, we combined the following elements:

- Return on capital and debt
- Return of capital (depreciation)
- Opex
- Net tax allowance

The calculation for return on capital and debt, regulatory depreciation and opex for DNSPs followed the same methodology as TNSPs and interconnectors, which was outlined in the previous section. The key difference between the two is with respect to tax depreciation.

For distribution networks, we instead assumed that DNSP assets have a tax standard life of 40 years (consistent with our asset life assumptions), and calculated the tax depreciation using the diminishing value method on this basis. This figure is based on a weighted average of asset life by value of the asset from available PTRM data.

3.3.4 Assigning DNSP costs to residential customers

To produce state-level distribution network cost estimates, the model first assumes a constant proportion of the revenue requirement is recovered from residential customers, based on the most recent Annual SCS Pricing Model (see Table 3.3 above). Finally, the model aggregated each DNSP costs to project DNSP costs at a regional level.

3.4 Jurisdictional schemes

State and territory governments have introduced policies that pass-through costs to DNSPs. If a policy meets certain criteria, DNSPs may apply to the AER for it to be classified as a jurisdictional scheme. If the application is approved, a DNSP may include the associated costs in its annual pricing proposal, including adjustments for over- or under-recovery in prior years.

We estimated the costs of such schemes, which are summarised in Table 3.5 below. In general, the method we used to estimate the costs of each scheme depends on how the scheme operates, the quantum of costs that are recovered from customers, and the level of information available for the scheme.

Table 3.5: List of jurisdictional schemes captured under the Network cost stack

Scheme	Cost (24-25, $m)	Description	Cost estimation method
ACT Large scale Feed-in Tariff (FiT) Scheme	99.9 (2022-23)	The scheme cost is associated with the net payments to the successful projects from the renewable energy auctions the ACT Government ran between 2012 and 2019.	Estimated based on AEMC-modelled wholesale prices, as explained below.
ACT Energy Industry Levy	1.7	Levy to fund the ACT's national and local energy industry regulatory costs.	Costs held constant in real terms.
ACT Utilities Network Facilities Tax	10.3	Tax on network facilities covering electricity, gas, sewage, water, and telecommunications. The tax is specified per km of network.	Costs increase over time proportion to electricity demand growth.
ACT Small and Medium Feed-in Tariff Scheme	14.5	Scheme costs associated with legacy small and medium-scale feed-in tariff scheme. The scheme closed to new applicants in 2011 but successful applicants had until December 2016 to connect. The payment is provided for 20 years from the date of connection.	Costs initially held constant in nominal terms until late 2020s before trending down based on the historical pattern of connections.
NSW Electricity Infrastructure Roadmap	341.2	In November 2020, the NSW Government released the NSW Electricity Infrastructure Roadmap. The scheme costs include funding Long Term Energy Supply Agreements (LTESAs), payments to network operators and associated administrative costs.	Estimated using a 'bottom up' estimate of costs as described below.
NSW Climate Change Fund	297.4	Provides funding to initiatives in NSW to reduce emissions and adapt to the impacts of climate change. The scheme costs are split 25:75 between residential and commercial & industrial consumers.	Costs held constant in real terms, in line with recent trends.
QLD Solar Bonus Scheme	157.6	Scheme costs associated with legacy support scheme for solar PV. Applications for the 44c/kWh scheme closed in 2012 but applicants had until June 2013 to connect. The expiration date of the 44c/kWh scheme is 1 July 2028.	Costs held constant in nominal terms until scheme expiry date.
QLD AEMC Levy	1.5	This amount recovers the contribution of the Queensland government to	Costs held constant in real terms.

Scheme	Cost (24-25, $m)	Description	Cost estimation method
		funding the AEMC.	
SA PV Feed-in Tariff Scheme	79.2	Scheme costs associated with legacy 44c/kWh support scheme for solar PV. The scheme ends on 30 June 2028.	Costs held constant in nominal terms until scheme expiry date.
SA AGL Designated Services Scheme	5.2	Payments to AGL to maintain Torrens Island Power Station Unit B2 as an available and functioning electricity generating plant until June 2026.	Use payments specified in SAPN's distribution licence until scheme expiry date.
Victoria Premium Solar Feed-in Tariffs	19.7	Scheme costs associated with legacy support scheme for solar PV. The scheme ends in November 2024.	DNSPs have provided cost estimates for the scheme for 2024-25.
Energy Safe Victoria Levy	20.1	Levy to fund the activities of Energy Safe Victoria, the state's independent safety regulator for electricity, gas, and pipelines.	Costs held constant in real terms.

Source: 2024-25 Annual Pricing Model for each DNSP, submitted to the AER

Finally, we used information provided by DNSPs to the AER to estimate the share of jurisdictional costs that are allocated to residential consumers. As noted below, more detailed modeling was required to project the costs of the NSW Electricity Roadmap and the ACT Large Scale FiT Scheme.

3.4.1 NSW Electricity Infrastructure Roadmap

In November 2020, the NSW Government released the NSW Electricity Infrastructure Roadmap, enabled by the Electricity Infrastructure Investment Act. The costs are recovered annually from electricity consumers via an annual payment from each NSW DNSP into the scheme, which are set annually under an AER determination.[27]

The Roadmap[28] includes several elements:

- **Long-Term Energy Service Agreements**, which are options contracts that are described below.
- **NSW Renewable Energy Zone Network Infrastructure Projects** and Priority Transmission Infrastructure Projects. As those costs reflect the costs of transmission capital investments, we modelled these costs based on the building block approach we adopted for TNSPs as described in Section 3.2 above. That is, we took publicly available estimates of project costs and timings, from planning documents such as the NSW Infrastructure Investment Objectives (IIO) report and AEMO's ISP. We then modelled the recovery of these costs from customers by

27 More information about the AER revenue determination process for the recovery of Roadmap scheme costs from DNSPs is available here: https://www.aer.gov.au/industry/registers/resources/guidelines/nsw-contribution-determination-guideline

28 Further information on the NSW Electricity Infrastructure Roadmap is available at https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap

treating them as if they were TNSP augmentation capital expenditure, including the flow-on costs to other building blocks such as tax and opex.

- **Waratah Superbattery** costs. These are payments made, ultimately, to the operator of the battery for the System Integrity Protection Scheme (SIPS) services provided by the battery. In short, payments are provided to the battery operator so it reserves charge to act as a "shock absorber" for the grid, to allow major transmission lines to with fewer operating restrictions at higher capacity to feed electricity into the major load centres in Sydney, Newcastle and Wollongong. These payments are based on the schedule provided in the AER's battery service determination for the project.
- **Scheme administration costs** for the Roadmap. We assume these costs remain constant in real terms, based on the most recent AER determination.

NSW Long-Term Energy Service Agreements

Under the Roadmap, Long-Term Energy Service Agreements (LTESA) are options contracts that offer generation, storage and firming projects the right to access minimum cash flows for periods within a contract term. The LTESA scheme costs are recovered by the NSW Electricity Infrastructure Fund Scheme Financial Vehicle (SFV). Specifically, the SFV recovers these costs by issuing contribution orders to NSW DNSPs, who subsequently recover contribution amounts from electricity retailers. Finally, retailers recover the amounts from NSW electricity consumers via retail bills.

Modelling approach, key assumptions, and inputs for LTESA estimation

We focus on projecting a reasonable, upper-bound estimate of costs based on public information, in particular, published Market Briefing Notes from AEMO Services, who was appointed as the Consumer Trustee for the Roadmap to plan and progress long-term investment.[29]

We have only included projects awarded an LTESA in Tender Rounds 1-4, since detailed information on the outcomes of Tender Round 5 was not yet publicly available. The published Market Briefing Notes specify the following key inputs:

- Strike prices in $/MWh for generation LTESAs (though these may be expressed in inequality terms, for example less than $35/MWh)
- Annuity caps in $/MW/year for storage LTESAs

The Market Briefing Notes explain that some of the successful tenderers have forfeited annuity or swap periods.[30] However, the number of periods forfeited for each project is not publicly available. Thus, we assumed that each project has an active swap or annuity payment in all forecast periods.

These documents also note in some cases, not 100% of project capacity is contracted under LTESA. However, the specific contracted percentage is not publicly available. Thus for our upper-bound estimate, we assumed that the entire project capacity is contracted for all projects.

Generation LTESA

For generation LTESAs, we combined the revenue and generation outputs from the PLEXOS wholesale market model to calculate an average price the generator receives per MWh.

29 These market briefing notes are available at: https://aemoservices.com.au/en/tenders

30 See, for example, Table 4 of the Market Briefing Note for Tender Round 4, available at: https://aemoservices.com.au/-/media/services/files/tender-round-4/240628-market-briefing-note-t4.pdf

In the case where the PLEXOS wholesale market model does not contain a generator specified in AEMO Service's Market Briefing Notes, we used a comparably sized and located generator.

If the average price is less than the LTESA strike price, the generator receives a payment per MWh equal to the difference between the two. If the average price is greater than the LTESA strike price, then the generator pays back the difference between the two.

Firming and Long Duration Storage LTESA

For firming and long duration storage LTESAs, we multiplied the generator's MW by the annuity cap in each forecast year where the generator is operational to calculate the maximum payment to each generator.

3.4.2 ACT Large-scale Feed-in-Tariff scheme

ACT sources most of its renewable electricity from large-scale generators located across eastern and southern Australia. Under the ACT Large-Scale FiT scheme, contract for difference (CfD) contracts were issued, and large generators can receive an agreed fixed price for the electricity they supply to consumers. The ACT's electricity distributor (Evoenergy) pays generators the difference between the agreed price and the actual value of each MWh in the wholesale market. These costs (or cost reductions) flow through to ACT consumers via retailers, increasing or decreasing household electricity costs.

Each contract issued under this scheme has a defined strike price ($/MWh), maximum annual energy volume (MWh per year), expected nameplate capacity (MW), and contract term. To model the scheme costs, we extracted the generation and price outputs for relevant generators from PLEXOS and sourced their respective FiT contracts from ACT legislation. The steps taken were as follows:

- for each generator, we calculated their electricity output relative to their maximum capacity over 10 years, on a half-hourly basis
- we calculated FiT payments for each half-hour by multiplying the difference between the FiT price and the spot price by the generator's output, applying the contract terms and any time limits. This includes some adjustments, such as incorporating a -$20 price floor as applicable
- we then summed the payment of all relevant generators by financial year and adjust for inflation to estimate the total cost of the scheme.

4 Renewable and energy efficiency schemes costs methodology

In this section we outline how we projected the costs of renewable/energy efficiency schemes that are recovered directly from electricity retailers, including both Commonwealth and State-based programs. In general, these schemes recover the costs of renewable or energy efficiency programs that provide incentives for investment in renewable energy systems or encourage energy efficiency measures, with the costs typically apportioned based on the amount of electricity that retailers purchase through the wholesale market.

4.1 Commonwealth schemes

The Renewable Energy Target (RET) is an Australian Government scheme that aims to reduce greenhouse gas emissions in the electricity sector and increase renewable electricity generation. It sets a target to deliver an extra 33,000 gigawatt-hours (GWh) of electricity from renewable sources every year from 2020 to 2030 by creating a market to incentivise the generation and use of renewable energy.

Over time, the RET has evolved and now comprises two schemes: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). These two schemes form part of the cost stacks.

The LRET incentivises investment in renewable energy power stations such as wind and solar farms. These power stations can create large-scale generation certificates (LGCs) for the eligible renewable electricity they produce. They can sell LGCs to liable entities (mainly electricity retailers) or companies who want to demonstrate renewable energy use.

Liable entities must purchase a certain percentage of electricity from renewable sources each year. They comply with this by buying LGCs and surrendering them to the Clean Energy Regulator.

On the other hand, the SRES incentivises households and businesses to install small-scale renewable energy systems, such as rooftop solar panels, solar water heaters and small-scale wind systems. System owners can create small-scale technology certificates (STCs) when an eligible system is installed.

Liable entities (mainly electricity retailers) must surrender STCs to the Regulator each year. This creates demand for STCs.

For both LRET and SRES, we estimated costs by multiplying a respective per-unit cost by the estimated volume of certificates generated. In figures below, we provide more details on our approach.

Figure 4.1: LRET cost calculation methodology

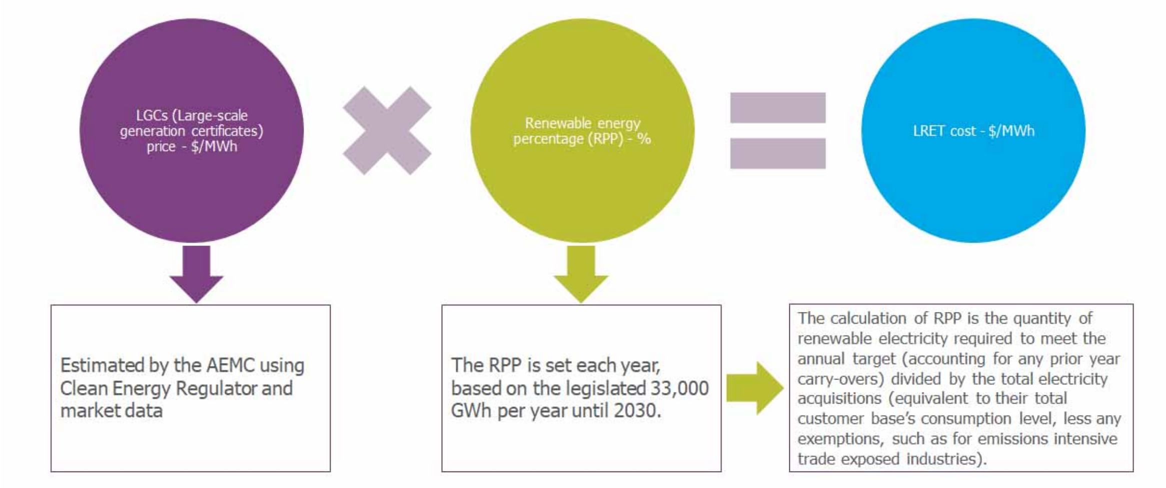
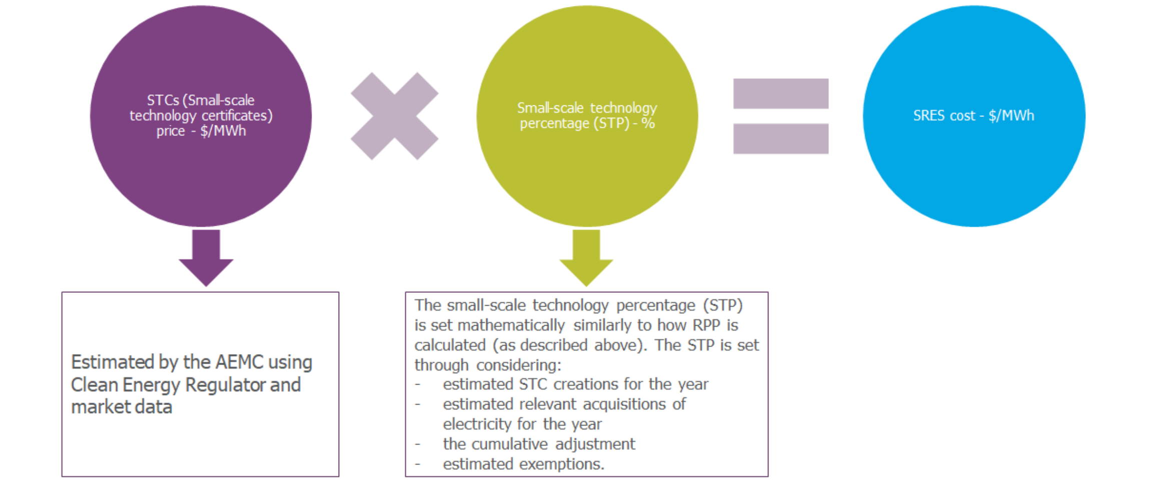


Figure 4.2: SRES cost calculation methodology



With the RET Scheme projected to end in 2030, the Commonwealth is introducing a Renewable Energy Guarantee of Origin (REGO) scheme. However, we have not included the REGO scheme because it is a voluntary scheme, unlike the RET schemes which are mandatory. Firstly, because the scheme is voluntary, it may be the case that only consumers who elect to consume 'green' electricity may face REGO scheme costs. Secondly, estimating the demand for REGO certificates is challenging due to the absence of compulsory acquisition requirements. Together with a potentially large supply of certificates from growing renewable generation, REGO certificate prices could be minimal when considering the supply-demand balance – and largely reflect the administrative costs of producing certificates. As more information becomes available, we may include REGO scheme costs in our cost projections.

4.2 State-based schemes

In addition to Commonwealth schemes under the RET, we also estimated the costs of several state-based energy efficiency schemes. These jurisdictional energy efficiency schemes are designed to assist consumers in reducing their energy consumption during peak and off-peak periods.

These schemes are funded by retailers, who have compulsory obligations to either purchase scheme certificates or undertake scheme activities. We estimated the costs associated with the following five schemes:

- NSW Energy savings scheme (ESS)
- NSW Peak demand reduction scheme (PDRS)
- VIC Victorian energy upgrades program (VEU)
- SA Retailer Energy Productivity Scheme (REPS)
- ACT Energy Efficiency Improvement Scheme (EEIS)

4.2.1 NSW energy savings scheme

The energy savings scheme (ESS) aims to deliver cost-effective energy savings for households and businesses by providing financial incentives to install energy-efficient equipment and appliances.[31] Under the Scheme, electricity retailers are required to purchase and surrender energy savings certificates to meet scheme targets. One energy savings certificate represents one notional megawatt hour of energy saved.

Energy savings scheme targets have been set out to 2050 and are expressed as a percentage of liable electricity acquisitions. To calculate the number of certificates required to be surrendered each year, we combined the scheme target with electricity demand from AEMO's 2024 ISP. Finally, to calculate scheme costs, we assumed that the price of energy savings certificates is constant (in real terms) consistent with recent spot and forward contract prices.

4.2.2 NSW peak demand reduction scheme

The peak demand reduction scheme (PDRS) aims to reduce peak electricity demand in NSW by providing financial incentives for households and businesses to reduce energy consumption during hours of peak demand.[32] Similarly to the NSW ESS, scheme participants are required to purchase and surrender peak reduction certificates to meet a scheme certificate target. One peak reduction certificate represents 0.1kW of peak demand reduction capacity averaged over one hour.

Scheme certificate targets (SCT) are calculated using the following formula:

$$SCT = \text{Forecast peak demand} \times \text{Peak demand reduction target} \times 10{,}000 \times n$$

Where n is the number of hours within the peak demand reduction period in one day. Peak demand reduction targets have been set out to 2050. We assumed that the value for n is constant through the forecast period and equal to its current value of 6. Finally, we used AEMO's 2024 ISP for forecasts of POE10 peak demand.

31 More information on the NSW energy savings scheme can be found here: https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/energy-savings-scheme.

32 More information on the NSW peak demand reduction scheme can be found here: https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme.

To calculate scheme costs, we assumed that the price of certificates is constant, consistent with recent spot and forward contract prices, and multiplied this with the estimate of scheme certificate targets.

4.2.3 VIC energy upgrades program

The Victorian energy upgrades (VEU) program aims to help Victorians reduce their energy bills and greenhouse gas emissions by providing access to discounted energy efficient products and services.[33] Under the program, energy retailers must surrender Victorian energy efficiency certificates (VEECs). Each certificate represents one tonne of greenhouse gas emissions reduction (CO2e). Certificates are generated after the completion of eligible activities. These include commercial and public lighting upgrades, water and space heating/cooling activities, appliance activities and others.

Targets for the number of VEECs that must be surrendered have been set until 2025. Post-2025, we assume that the number of VEECs to be surrendered increases linearly, consistent with the trend between 2021-25. To calculate VEU program costs, we combined the certificate targets with an estimated certificate price. Certificate prices were held constant through the forecast period, based on the prices of recent forward contracts observed from market data.

4.2.4 SA retailer energy productivity scheme

The objective of the retailer energy productivity scheme (REPS) is to improve energy productivity for households, businesses and the broader energy system, with a focus on low-income households.[34] The REPS achieves this by setting annual energy productivity targets to be met by energy retailers. To achieve these targets, retailers offer incentives to deliver productivity activities, such as a discount on services, free products or cash rebates.

REPS targets are only available until 2025. Post 2025, we assume that the REPS target increases linearly, consistent with the average annual change between 2021 and 2025. To calculate REPS costs, we assumed that the per-unit costs associated with achieving the target was equal to the average per-unit cost reported in the last 3 REPS Annual Reports.

4.2.5 ACT energy efficiency improvement scheme

Under the energy efficiency improvement scheme (EEIS), electricity retailers are required to help households and small-to-medium business save energy under the Energy Efficiency (Cost of Living) Improvement Act 2012.[35] This is achieved by either delivering eligible savings activities (such as insulation, efficient heating and cooling systems, electric hot water heat pumps, etc.) or by paying an Energy Savings Contribution (ESC) to the ACT Government.

The amount of energy savings activities or contributions payable is determined by a prescribed energy savings target expressed as a percentage of total electricity sales in the ACT. For 2024 and 2025, the target is set at 14.6%.

To estimate EEIS costs, we assumed that the current target of 14.6% is maintained until 2030. 2030 is the final compliance period under the Energy Efficiency (Cost of Living) Improvement Act 2012. For simplicity, we assumed that the cost of eligible activities is equal to the ESC, and that

33 More information on the Victorian energy upgrades program can be found here: https://www.esc.vic.gov.au/victorian-energy-upgrades/about-victorian-energy-upgrades-program.

34 More information on the SA retailer energy productivity scheme can be found here: https://www.escosa.sa.gov.au/industry/reps/overview.

35 More information on the ACT energy efficiency improvement scheme can be found here: https://www.climatechoices.act.gov.au/policy-programs/energy-efficiency-improvement-scheme.

this is held constant for the forecast period. The ESC is currently set to $27.43/MWh by the scheme regulator (the ICRC). Finally, we combined these figures with electricity demand forecasts from AEMO's 2024 ISP to produce EEIS costs.

5 Retail and metering costs methodology

5.1 Retail costs

A retailer's cost stack generally involves:

- network costs charged by network operators for the transmission and distribution of electricity
- wholesale costs of purchasing electricity from the wholesale spot market, and of managing price exposure
- costs of complying with renewable/energy efficiency schemes, both state and national
- retail operating costs, accounting for bad and doubtful debt.

Network costs, wholesale costs and renewable/energy efficiency schemes costs were directly sourced from the corresponding component in the model, and their methodology is discussed in the corresponding sections of this paper.

Retail operating costs were forecasted based on the figures reported by the ACCC in the December 2023 *Inquiry into the NEM*. As these costs have been relatively stable over time, and given there is a lack of alternate data, we assume retail operating costs remain constant in real terms, in line with the most recent data, over the outlook. Bad and doubtful debt per residential customer were also reported by the ACCC. Beyond 2023, we forecasted bad and doubtful debt based on our customer demand forecasts and adjusting for inflation.

Lastly, we aggregate the elements of the cost stack and apply a 4% retail margin. Retail margins reported by the ACCC have seen a declining trend since a peak in 2016-17 and are currently at 2.3%. Our assumption of a 4% margin partly reflects an expectation that declining retail margins are unlikely to continue. It also reflects that the AER's retail allowance, in the 2024-25 DMO, was set at 6%.[36] A 4% margin is therefore an approximate midpoint of these different data sources.

5.2 Metering costs

On 28 November 2024, the AEMC completed a rule change to optimise the roll-out of smart meters to consumers and achieve universal uptake by 2030. As such, our modelling reflects the costs associated with its accelerated rollout.

Victoria has already achieved a near-universal roll-out of smart meters through a DNSP-led deployment strategy. Outside of Victoria, retailers will be responsible for smart meter deployment. As such, we adopt different methods to estimate costs for Victorian and non-Victorian consumers.

Victorian metering costs

For Victorian consumers, we projected metering costs based on the Annual Revenue Requirements (ARR) set by the AER in each DNSP's metering post-tax revenue model (metering PTRM). Specifically, we used the ARR's at the end of the current determination period, and assumed these increase beyond the regulatory period based on the growth in customer numbers. In effect, we assume that the metering cost per customer stays constant, given that smart meters in Victoria have already reached near-universal deployment.

Non-Victorian metering costs

36 Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Final%20determination%20-%20Default%20market%20offer%20prices%202024%E2%80%9325%20-%2023%20May%202024.pdf

In other NEM jurisdictions, the costs of smart meters are recovered from retailers, while the costs of reading accumulation meters (and any un-depreciated capital costs) are recovered through DNSP charges. We project each separately.

Metering costs incurred by retailers

We multiplied a projection of (1) the number of smart meter customers by (2) the cost per smart meter.

1. Number of smart meter customers
   - Smart meter customers were estimated using residential customer numbers and data from the AER. Essential Energy, Evoenergy and SA Power Networks reported legacy metering customer number forecasts for 2025 to 2030 in their metering PTRMs. By taking the difference of these legacy meter forecasts from each of their total residential customers, we derived an estimate of smart meter customer numbers. For the remaining DNSPs, we estimated that smart meter penetration would reach 100% by 2030 from their current levels, by applying a constant yearly percentage increase.
2. Costs per smart meter
   - Smart meter costs per customer were available for Ausgrid, Essential Energy, Energex and SA Power Networks from the 2023-2025 AER DMOs. For these five DNSPs, we projected costs based on the 3-year average of their historical costs. The average of these costs in each year were taken as an estimate for the remaining non-Victorian DNSPs.

Metering costs incurred by DNSPs

If available, we firstly based DNSP metering costs on the Annual Revenue Requirement (ARR) determined by the AER in the metering post-tax revenue model (metering PTRM), adjusted for inflation.

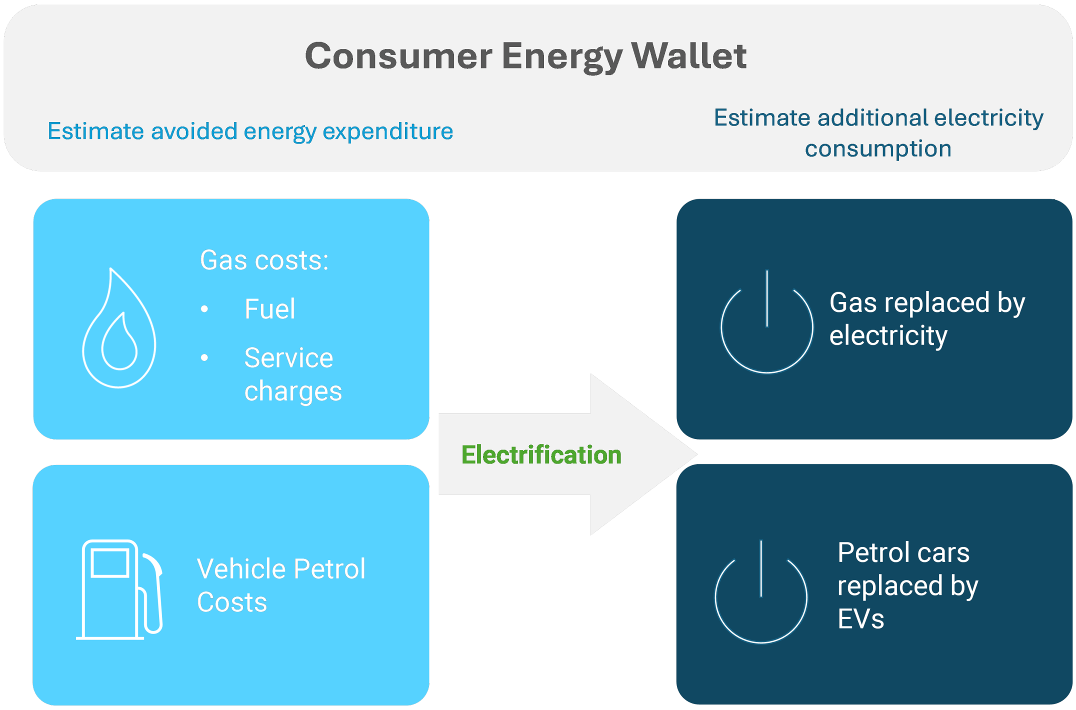
Beyond each regulatory period, we forecasted non-Victorian DNSP costs by projecting opex requirements. This is because all DNSPs report metering capital costs will be fully depreciated by the end of the current regulatory determination period. However, until smart meters are fully rolled-out, DNSPs will still incur operating expenditure to read any remaining accumulation meters. As part of its 2024-29 regulatory proposal to the AER, SA Power Networks estimated that a 1% increase in smart meters was correlated with a 0.55% reduction in metering opex, which is the assumption we have applied to all non-Victorian DNSPs. We forecasted the average opex over the next regulatory period by: multiplying the average opex of the current regulatory period; scaling it in proportion to the increase in smart meter customers over the next period; and applying a 55% ratio.

6 Energy Wallet methodology

6.1 Why we are examining the energy wallet

One of the most notable and significant changes occurring in the Australian economy as part of the transition to net-zero is the electrification of transport and gas appliances. For example, the 2024 ISP forecasts that residential consumption attributable to electrification, including electric vehicle load, will rise from ~0.4 TWh in 2024 to ~26.1 TWh in 2034. While electrification will lead to higher levels of residential electricity demand, it will also result in reduced fuel (petrol) and gas consumption by households, as electricity consumption replaces the costs associated with running gas appliances and internal combustion engine (ICE) vehicles (see Figure 6.1).

Figure 6.1: How we estimated the Consumer Energy Wallet



We therefore formed a 10-year outlook for household energy costs, by combining:

- Estimates of the rate of electrification from AEMO's ISP and GSOO
- Our price outlook for residential electricity costs
- An outlook for a typical household's expenditure on fuel and gas
- A projection for total customer numbers (see Box 1).

The following sections outlined how we derived estimates for the different electrification scenarios we considered. Please note that our estimates of household energy costs do not include any upfront capital costs a household may incur if they electrify. This work is not intended to determine the investment case for electrifying transport and fossil-fueled appliances. Rather, this work takes AEMO's forecasts of electrification in the ISP and GSOO as given and estimates the annual energy wallet costs for consumers at household level.

Box 1: How we estimated customer numbers

To estimate costs on a household level, an estimate of residential customers or connection numbers is required. To do this, we sourced the current year's customer numbers from each DNSP's Annual Pricing Proposals in 2024-25. We then projected future customer numbers for each DNSP by applying a growth rate (or number) for that DNSP. This rate (or number) was obtained from various sources, including DNSP's Regulatory Information Notices, AER's regulatory determinations, the network's own strategic reports, or the recent historical growth in customer numbers, based on data availability. We also adopted an average when multiple data sources are available and no single source is considered more accurate than others.

6.2 Estimating energy expenses for EV owners

Households who replace their internal combustion engine (ICE) cars with an Electric Vehicle (EV) save on fuel costs but consume more electricity through EV charging. To estimate the net energy-cost savings of owning an EV, we:

- projected the fuel costs faced by ICE owners
- quantified additional electricity consumption based on AEMO's EV charging behaviour forecasts, and
- overlayed our electricity cost forecasts to the additional electricity consumed.

These steps are explained below. Please note that we have not conducted a full assessment of the costs (as a transport sector study) associated with owning an electric vehicle (EV) as opposed to an ICE vehicle. Doing so would include a suite of costs not considered in this report. These include – but are not limited to – upfront purchasing costs, insurance premiums, road user charges, servicing costs and depreciation. The focus of this work, however, is on the energy costs faced by a household.

6.2.1 Fuel costs

The basis for our assumptions on annual fuel costs associated with owning an ICE vehicle came from the most recent ABS Survey on Motor Vehicle Use (SMVU), published in 2020. For the purpose of this analysis, consumers were assumed to either own one EV or one ICE car. This car would be driven the average amount each year, based on the SMVU data on the annual average distance travelled per vehicle, as well as the average fuel consumption per kilometre of travel. These have been used alongside a simple forward projection of fuel prices, based on the ACCC's June 2024 Quarterly Report on the Australian Petroleum Market[37] to determine the fuel cost savings faced by an EV owner.

6.2.2 Charging costs of an EV

We developed an EV charging profile based on AEMO's 2023 Inputs, Assumptions and Scenarios (IASR) EV Workbook. The workbook provides the following key information:

- Forecasts of the number of battery electric and plug-in hybrid electric vehicles by state, year, and size
- EV charging profiles by state, vehicle type, behaviour type (e.g., convenience charging, daytime charging, nighttime charging etc.), and whether it is a weekend or weekday

37 Available at: https://www.accc.gov.au/about-us/publications/serial-publications/australian-petroleum-industry-quarterly-reports.

- The proportion of vehicles following each charging profile in each year.

We calculated a charging profile for each state that is the weighted average with respect to both charging behaviour type, and vehicle size, using the 2024-25 figures provided by the 2023 IASR EV Workbook. For simplicity, we assumed that this profile is constant across all forecast years.

Finally, we also calculated two alternative charging profiles. In the first, we assumed that all EV owners follow daytime charging. In the second, we assumed that all EV owners charged their EV based on AEMO's convenience charging profile. Both alternative profiles were also calculated as weighted averages for the 2024-25 year, and held constant over the 10-year outlook.

6.3 Electrification of household gas

Switching to electric appliances saves on gas costs but also results in additional electricity consumption. The process for calculating the cost impact of electrifying gas appliances resembles the equivalent calculation for electric vehicles. The key differences are:

- Avoided gas consumption is based on an average (mean) household gas consumption figure
- Gas customers also incur a service charge, which will change over time based on the number of customers connected to the gas network

We elaborate on these steps below. To summarise, our projections are calculated based on the gas consumption of the average (mean) household, and an estimate of the average additional electricity households who switch off gas will consume.

6.3.1 Avoided gas costs

In our analysis, gas prices were assumed to remain at the current price cap placed on domestic gas supply contracts. Average household gas usage by state was derived from the CSIRO Technical Report that was provided as an addendum to Energy Consumers Australia's *Stepping Up* report.[38] We used these two figures to determine the gas fuel cost customers face.

Projecting gas service charges requires a projection of the number of gas customers who electrify. AEMO's 2024 GSOO provides a forecast of the reduction in residential gas consumption that is attributable to electrification. These, with the household consumption figures derived from the CSIRO report mentioned above, were used to forecast the number of gas customers who electrify.

To calculate gas service charges, our starting point for this projection was to take the cheapest big-3 standing offer in each state in September 2024 to form our prices for 2024-25. We then used Regulatory Information Notices provided to the AER by gas distribution networks to form assumptions on capex spending and depreciation by gas networks over the outlook. For simplicity, we assumed steady capex spending in the future and straight-line depreciation. The gas network asset base, which was projected for each gas network based on depreciation and capex, is paid for by a declining number of gas customers (which we calculated above). These figures were used to derive an assumed year-on-year change in gas service charges in each state.

6.3.2 Additional electricity consumption

The 2024 GSOO provides a forecast of the impact of electrification on residential gas consumption. Additionally, as part of the 2024 ISP, AEMO provides forecasts of the increase in residential electricity consumption that is attributable to electrification, excluding EV charging.

38 The CSIRO report is available at: https://energyconsumersaustralia.com.au/wp-content/uploads/CSIRO-Technical-Report-Stepping-Up.pdf.

These figures were reconciled to derive an estimate of the electricity consumption required to replace 1 GJ of residential gas consumption. These figures for additional electricity consumption were overlayed against our price forecasts to determine the net impact on household energy costs for consumers who electrify their gas appliances.

6.4 Rooftop Solar

Households can also reduce electricity costs if they install rooftop solar or household batteries. In Price Trends we have modelled the former.

To project the electricity cost savings of installing rooftop solar, we:

- Assumed that a household would install a typically sized rooftop PV system of 7kW
- Derived a solar output profile for each jurisdiction, given that weather conditions vary across Australia
- Estimated how much the solar output would reduce net electricity costs, based on our residential electricity price forecast. These estimates covered both the reduced amount of electricity that households would purchase from the grid, but also any revenue that households would earn through solar Feed-in-Tariffs.

The solar PV generation profiles we adopted for each region were taken for an indicative weather year and do not vary year-to-year over the outlook period. These profiles were calculated using the US Department of Energy's PVWatts Calculator.[39] The calculator estimates the energy output of rooftop PV systems throughout the world (including Australia), and we are unaware of a comparably detailed estimator available specifically for Australia. To generate a profile for each jurisdiction, we calculated a generation profile for each of the state capital city to be indicative for all customers in that state.

We then calculated the net electricity cost saving from solar PV. First, we subtracted the solar generation profile from estimates of typical daily residential household electricity load, published in the AER's 2024-25 DMO. This allowed us to calculate the reduction in the amount of electricity that would be purchased from the grid. Second, if the solar output was greater than the total household electricity consumption in any periods in the day, we assumed that the household would earn feed-in-tariffs for any additional consumption. To value these feed-in-tariffs, we used a state-based average of feed-in tariffs from large retailers, and assumed the per-unit feed-in tariffs increased, or decreased, in the same proportion to the base case electricity price over time.

39 Available at: https://pvwatts.nrel.gov/

7 Modelling limitations

This section provides a summary of some of the key assumptions we applied to develop a 10-year outlook for residential electricity prices. The preceding sections of the report provide more details. The list is not designed to be exhaustive, but rather to summarise the limitations and explain their potential impacts on our estimates.

Table 7.1: Modelling limitations

Key modelling assumption or limitation	Description	Impact on prices
Key assumptions that apply to all electricity cost components		
Future demand, supply, and grid constraints	Our electricity demand, generation profile and system representation are based on the 2024 Final ISP published by AEMO. The ISP identifies the optimal development path of a transition to net zero by 2050, whereas our emphasis is on analysing the cost components within the energy supply chain that are influencing changes in residential electricity prices. Nevertheless, we consider ISP to be a long-term projection that can meaningfully help construct our base case (with several minor adjustments outlined in chapter 2).	The ISP represents an optimal system development path that coordinates new generation build and retirement to maintain reliability, achieve emissions targets, and ensure that the cost to meet expected demand is minimised. As such, our base case represents one where there is timely and efficient investment, and well coordinated policy. The energy transition may not be as smooth as this plan, as there are a range of unexpected changes to supply or demand conditions that could lead to significantly different prices. Some of these risks are explored through scenario analysis.
Key assumptions made when modeling wholesale costs		
Bidding assumptions	We have adopted static bidding behaviour in the spot wholesale market, tailoring our approach to each generator type as outlined in section 2.1.1. Our bidding assumptions attempt to proxy the average behaviour of market participants over time, as the supply and demand balance in the ISP changes over time. In reality, bidding behaviour is significantly more dynamic and can change rapidly as generators optimise their bidding (and rebidding) behaviour in response to	Although our approach will respond to projected changes in supply and demand, it still relies on historical bidding behaviour which may not represent bidding patterns in the future. While we attempt to proxy some of the real-world bidding dynamics through the volatility adjustment summarised below, it will not fully capture the impact of real-world constraints

Key modelling assumption or limitation	Description	Impact on prices
	changes in the supply-demand balance, real-world constraints and outages.	on wholesale prices.
Price volatility	A limitation of modelling wholesale prices using the PLEXOS ISP model is that it is very difficult to get the same volatility in prices that occurs in the real world. To approximate the impact of real-world volatility we performed a post-modelling adjustment to increase prices based on the historical relationship between the reserve margin and prices at the regional level.	Our approach assumes: • a tight supply-demand balance is a reasonably good instrument for when price volatility is likely to arise, and • the historical relationship between price volatility and the supply-demand balance will be relatively stable over the outlook. Our approach could underestimate prices to the extent that high wholesale prices might occur in periods *without* a tight supply-demand balance.
Waratah Super Battery bidding	We have not adjusted the bidding behaviour of the Waratah Super Battery for the System Integrity Protection Scheme (SIPS) services provided by the battery. The operator of the Waratah Super Battery is being paid by Transgrid to constrain its operation to act as a “shock absorber” for the grid, reserving 700 MW to 1400 MWh across the year to allow the main transmission lines to feed electricity into the major load centres in Sydney, Newcastle and Wollongong. This constrained operation should be reflected in the battery’s bidding behaviour, which we have not adjusted for.	There are two potentially offsetting effects: • In ‘normal’ periods the battery will supply less electricity, and wholesale prices could be higher than we have modelled. • In ‘constrained’ periods its output will be maximised, and wholesale prices could be lower than we have modelled. We have not attempted to model the net impact of the two effects, as we do not have any information on the battery’s bidding behaviour.
Load shape	Our outlook is based on spot wholesale prices, and is a weighted-average price of residential and non-residential demand. But residential demand is generally peakier compared to non-residential demand, with consumption more	What matters to the outlook for prices is the extent to which the residential load shape premium increases or decreases over time. That is, if residential peak demand increases or reduces relative to other demand.

Key modelling assumption or limitation	Description	Impact on prices
	concentrated in the afternoon peak with higher-than-average prices. So households should face a higher-than-average wholesale price. This can be captured by estimating a 'residential load shape premium'.	Demand forecasts are not available at the level of detail required for us to capture this factor. However, we note that residential demand could become less peaky to the extent that consumers can take advantage of flexible loads. Our CER orchestration scenario also provides estimates of the potential price impact if residential demand becomes more concentrated in the evening peak.
Key assumptions made when modelling network costs		
Concessional finance	The CEFC provides lower-cost finance for up to $19b of projects 'that facilitate the timely delivery of grid and transmission projects'. A substantial proportion of this financing is allocated to TNSPs for priority transmission projects, including $4.7 billion for NSW, $2.25 billion for Victoria, and Marinus Link. However, the individual financing terms of each project are commercial in confidence.	Our modelled prices will be an over-estimate, as we apply a regulated WACC to these projects which does not account for the concessional financing benefit individual projects may receive.
DNSP capex	We projected DNSP capital expenditure (capex), after the AER revenue determination period, based on the historical RAB-capex ratio. This is in contrast to a detailed bottom-up approach we adopted for TNSP capex estimates, because we have more detailed cost estimates available.	To the extent that capex is lumpy, or cyclical, this will over- or under-estimate costs. To capture this risk, we conducted a scenario that doubled the level of DNSP replacement capital expenditure. The scenario showed this modelling limitation had a minor impact on prices over the 10-year outlook.
Interregional settlement residues (IRSR)	Interconnectors facilitate the flow of electricity across states, from low-priced regions to higher-price ones. These energy flows from low- to high-price regions generate positive settlement residues, the	Excluding IRSR from network costs will mean that we have over-estimated prices. However, it is also year-to-year *changes* in IRSR (and SRA proceeds) that

Key modelling assumption or limitation	Description	Impact on prices
	rights to which are allocated through settlement residue auctions (SRAs). These SRA proceeds are then netted from transmission charges, to reduce residential electricity prices. We have excluded IRSR from our network price forecasts because: • We are unable to model the relationship between changes in IRSR and settlement residue auction proceeds • Due to computational limitations, the ISP has fewer constraints than in the 'real-world', which means more energy is projected to flow across states in high price periods than in reality. Instead, we account for price volatility, and the Cumulative Price Threshold, as post-modelling adjustments to partially offset this issue.	impact the price outlook. While new interconnection between states over the outlook – such as the introduction of Project Energy Connect (PEC) and Marinus Link – is projected to lead to more energy flowing across states, the impact on IRSR would be partially offset by smaller price differentials between regions in the NEM.

8 Scenario analysis

We modelled different scenarios to shed light on the risks and opportunities to the 'base case' outlook which assumes an optimal development path. This section outlines the supply or demand parameters we changed when conducting these scenarios.

Importantly, these scenarios were modelled as unanticipated changes to the system. We changed individual supply and demand parameters, and re-estimated wholesale and network costs, without changing the long-term generation profile. In reality, consumers, generators, networks and policy-makers would change their behaviours and investment decisions to mitigate these shifts. The intent of this approach is to provide policymakers and stakeholders with insights to how these risks could affect prices if they occurred, without policy action to mitigate the impacts.

These sensitivities are summarised in Table 8.1 below.

Table 8.1: Parameters we changed when running scenario analysis

#	Sensitivity	Description	Period impacted
Supply side			
1	Battery and hydro project delays	Hydro: • Snowy 2.0 delayed 12 months from December 2028 to December 2029 • Borumba delayed 12 months from June 2030 to June 2031 Batteries: • All new entry battery builds delayed by 12 months including those built under the LTESA and VRED schemes • Largest "anticipated" battery in each region delayed 12 months • Waratah battery upgrade delayed 12 months	July 2026 to June 2031
2	Wind and transmission connection delays	• Buildout of new wind resources in each renewable energy zone delayed by 12 months • Marinus, VNI West and New England REZ Transmission Link delayed 12 months, with associated network cost increases of 30%	Wind delays impact July 2026 to the end of the horizon and major transmission delays impact September 2028 to July 2031
Demand side			
3	Faster electrification	An additional 10TWh of electrification demand in each year from FY27 onwards (equivalent to a one-third increase to the rate of electrification in FY30, or a 5% increase in total FY30 demand)	FY27 onwards
4	Slower electrification	A delay in electrification demand as forecast by the ISP by 12 months	Entire horizon
5	Sub-optimal	100% of EV users charge using the "convenience"	Entire horizon, but the

#	Sensitivity	Description	Period impacted
	CER orchestration	charging profile as defined in AEMOs ISP, which is primarily charging in the evening peak	impact is more significant in the later years
Networks			
6	Higher network WACC	Weighted Average Cost of Capital (WACC) for networks are 1% higher over the next 10 years	Entire horizon, but impact increases over the horizon with trailing average cost of debt
7	Lower network WACC	Weighted Average Cost of Capital (WACC) for networks are 1% lower over the next 10 years	Entire horizon, but impact increases over the horizon with trailing average cost of debt
8	Network CAPEX increase	Network replacement capital expenditure (CAPEX) is doubled after the current AER determination periods	FY27 onwards

When modelling the impact of each scenario on wholesale costs, we re-ran the PASA, MT Schedule and ST Schedule phases only – and did not rerun the long-term capacity schedule.

To estimate the impact of the demand-side scenarios on network costs, we calculated:

1. The impact of the scenario on peak DNSP demand. This is because peak demand is the major driver of DNSP investment. For the CER scenario, this involved calculating the volume of demand that was assumed to be shifted into the peak demand window. For the faster, and slower, electrification scenarios, we calculated the overall impact on peak demand.
2. The additional investment needed (or avoided) to service the increase (or reduction) in peak demand by applying an estimate of the long-run marginal cost (LRMC) of network investment. Specifically, we used the weighted average of each DNSP's LRMC estimates, adopting Average Incremental Cost estimates, to ensure consistency in approach across networks.