Australian Energy Market Commission

REVIEW

Methodology

Residential Electricity Price Trends 2025

4 December 2025

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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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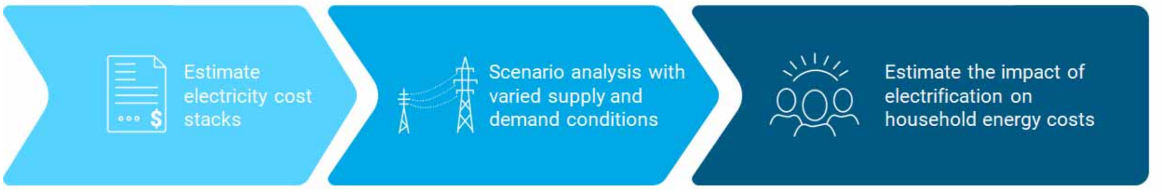
1 Introduction

This methodology paper discusses how we projected residential electricity prices and household energy costs over the next 10 years. It should be read in conjunction with the AEMC's *Residential Electricity Price Trends 2025* report (hereafter 'Price Trends 2025'). This paper provides the reader with background information on the assumptions, methodology and data sources used in Price Trends 2025.

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

- Estimate and project the cost stack components of electricity prices, which comprise: wholesale, network, retail and renewable/energy efficiency schemes costs.[1]
- Analyse scenarios to consider how changes to electricity supply and demand could impact our outlook for residential electricity prices. These scenarios also tested the robustness of our models to our key assumptions.
- Consider how our electricity price outlook and electrification actions by households could impact their total energy expenditure (known as an 'energy wallet') to understand the consumer impact of the energy transition.

Figure 1.1: Overall approach for Price Trends 2025



We modelled the National Electricity Market (NEM), including Queensland (QLD), New South Wales (NSW), the Australian Capital Territory (ACT), Victoria (VIC), South Australia (SA), and Tasmania (TAS). Western Australia and the Northern Territory were not included in our model.

Our models use the Australian Energy Market Operator's (AEMO's) latest 2024 Integrated System Plan (ISP) model as a basis. As outlined in section 2.1 and section 3.2 below, for Price Trends 2025 we use the 2024 Final ISP, and update this for AEMO's latest Step Change demand and supply information from the 2025 ESOO, 2025 IASR and 2025 ENOR publications.[2]

All results in our report are presented in 2025-26 real dollars. All year references are to financial years (for example, 2026 refers to 2025-26 and 2035 refers to 2034-35), not calendar years. Results 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). For Price Trends 2025, our analysis is based on data as at end-September 2025. Our projected electricity prices and costs exclude GST, unless stated otherwise.

1 Our model projects cost stacks, rather than estimating the individual tariffs faced by consumers, which can vary significantly.

2 ESOO - Electricity Statement of Opportunities; IASR - Inputs, Assumptions and Scenarios Report; ENOR - Electricity Network Options Report.

This paper has been structured as follows:

- **Chapters 2 – 5**: Methodology for each element of the residential electricity cost stack, including wholesale, network, renewable/energy efficiency schemes and retail costs
- **Chapter 6**: Methodology for projecting growth in residential electricity consumption and NEM customer numbers
- **Chapter 7**: Methodology for estimating household energy expenditure with different degrees of electrification
- **Chapter 8**: Summary of the key modelling assumptions and limitations
- **Chapter 9**: Approach undertaken in our scenario analysis

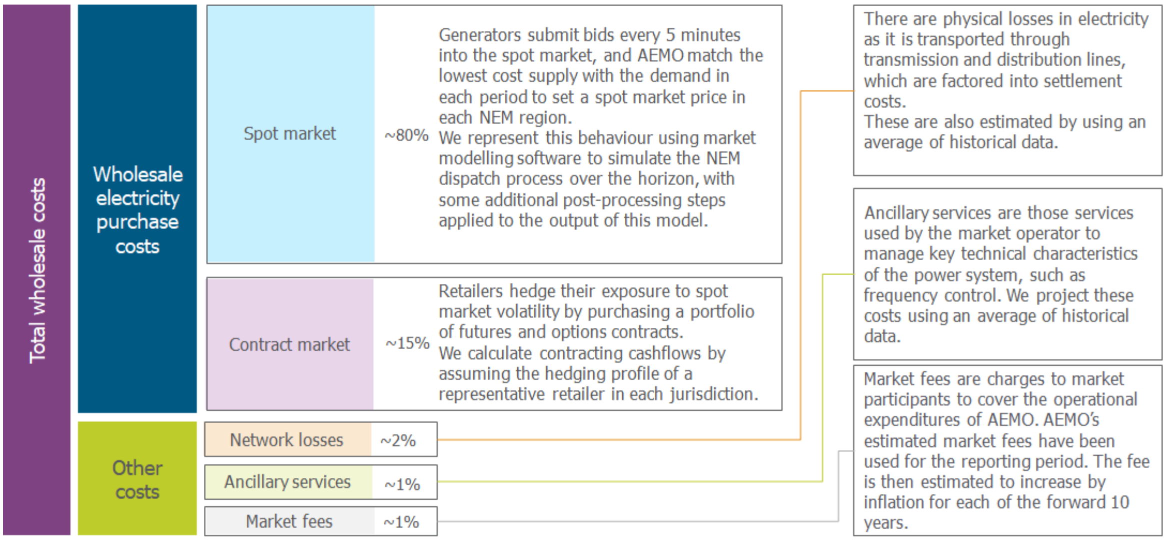
We have made several data updates and methodological refinements for Price Trends 2025, including:

- Updated key demand and supply parameters. Because AEMO's ISP is updated biannually, for this year's report we have used the 2024 ISP Step Change scenario, and updated it based on new data from AEMO's 2025 ESOO, IASR and ENOR publications. Our approach is summarised in section 2.1.1).
- Simplified how we model wholesale price volatility, as described in section 2.1.2 and section 2.1.3.
- Included home batteries into our analysis of the household energy wallet, as outlined in section 7.3.5.
- Modelled a typical household's upfront costs of electrifying assets, and the net payback period, as explained in section 7.4.
- Modelled five new scenarios into our analysis, which capture the impact of: higher hedging costs; increased fuel costs for gas generators; decreased level of reliability from coal plants; a faster uptake of home batteries; and a faster roll-out of wind and transmission assets. These are described in chapter 9.

2 Wholesale costs methodology

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

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, wholesale electricity prices in the NEM are determined every five minutes for each region based on an auction process. The prices can vary from $-1,000/MWh to $20,300/MWh in each period.[3] based on current demand, and the bids offered by generators to meet this demand, which typically reflect each generator's short-run marginal cost (SRMC). Specifically, generators of different types submit their proposed price and volume bids in 10 different bands to AEMO for the right to dispatch. The market is settled every five minutes, with supply balancing demand.

Figure 2.2: Our approach to projecting wholesale electricity purchase costs

3 Note that the market price cap and price floor are indexed and scheduled to increase each year from FY26-FY28. For more information on how these settings are handled in our model see section 2.1.4.

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

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.[4] 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[5], 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' assumptions[6]

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

2.1 Spot price methodology

We use a linear optimisation software - PLEXOS - to create a model of the NEM that is used to generate dispatch outcomes, including spot prices, every 30 minutes for each NEM region. This PLEXOS model is a representation of the NEM at a sub-regional level, capturing all the generation and storage sources (including future projects) and their characteristics, and a simplified representation of the transmission network, including high level constraints. We develop this base case model using a combination of sources published by AEMO, including the:

- Integrated System Plan (ISP)[7],
- Electricity Statement of Opportunities (ESOO)[8], and
- Inputs, Assumptions and Scenarios Report (IASR)[9].

4 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 the model is reasonable.

5 A peak electricity contract is an agreement that allows the buyer to purchase one megawatt (MW) of electrical energy per hour during the specific peak load period for a given price. An Asian option is a contract where the payoff is based on the average price of electricity over a specified period.

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

7 2024 Integrated System Plan published 26 June 2024

8 2025 NEM Electricity Statement of Opportunities, published 21st August 2025

9 2025 Inputs Assumptions and Scenarios Report and Workbook, published 28th August 2025

The development of our base case PLEXOS model is described in section 2.1.1. We have adjusted our approach since 2024 to take into account the fact that AEMO publishes an ISP model every two years.

This market model is used to generate spot prices using SRMC dispatch. We then apply two additional adjustments to ensure that prices are reflective of real-world outcomes:

- A 'volatility uplift' to capture real-world price volatility, and
- An adjustment to capture the impact of the MPC and CPT

These adjustments are described in more detail in section 2.1.3.

2.1.1 PLEXOS base case model

In our modelling, we use AEMO's 2024 Integrated System Plan (ISP) model as our underlying market model, taking the Step Change scenario as the central case, and making adjustments for updated information.

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) and modelling methodology.[10] 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.

In our 2024 report, we were able to use the published 2024 ISP model with only minor adjustments to generator characteristics. However, as there have been relatively large changes to AEMO's demand projections since this publication, we have built on the 2024 ISP more significantly this year by utilising updated data from the 2025 ESOO and the 2025 IASR. Our approach to developing our base case PLEXOS model is to:

1. Start with the published 2024 ISP model, adopting its representation of the network through sub-regions and renewable energy zones
2. Update the model with the following data from the ESOO and IASR:
    a. Operational demand projections
    b. Anticipated and committed project start dates
    c. Generator characteristics, including technical parameters and reliability settings
    d. Demand-side-participation projections
    e. Policy targets and constraints
3. Update major transmission project timings in line with the latest Transmission Augmentation Information from AEMO[11]
4. Run the 'capacity expansion' model (also known as the long term, or LT model) ,with the updated data in step 2 incorporated in the 2024 ISP model, to generate a buildout schedule for new generic entrants

10 ISP Methodology published June 2023.

11 NEM Transmission Augmentation Information July 2025

5. Convert the LT 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 take the optimal build and retirement schedule from the LT model, and use it to determine the most efficient dispatch outcome over the short and medium term. This modelling replicates 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 model compared to AEMO's ISP and ESOO models for the purpose of Price Trends:

- We changed Eraring's retirement date from 2025 to 2027 in line with our modelling from 2024, and as AEMO's 2025 ESOO model includes this adjusted retirement date
- We initially ran the ST dispatch model using SRMC-based bidding (see section 2.1.2)
- We added a variable operating and maintenance charge to batteries to temper the effect of perfect foresight (see section 2.1.2)
- We used the 2021 weather reference year as the basis for VRE (Variable Renewable Energy) output and electricity demand, rather than the 'rolling reference year' approach used in the ISP (outlined in more detail in section 2.1.5)
- 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).

We did not change the ISP model for the following developments:

- The introduction of the Firm Energy Target (FET) by the South Australian Government, as it is not fully clear how this constraint will be modelled in the ISP until the Draft 2026 ISP is released.
- October 2025 announcements from the Queensland Government and Rio Tinto about the life of coal-fired power stations, as these recent changes were outside of the modelling window for the 2025 report.

Following these changes to the base ISP, 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 once 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 2.1.3)
- Prices were adjusted according to the market price cap (MPC), cumulative price threshold (CPT) and administered price cap (APC) [12], 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, spot prices are capped at the 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.

12 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 $20,300/MWh (the MPC) for each interval, and when the rolling total of the last 7 days of prices is above $1,823,600/MWh (the CPT) then spot prices are capped at a reduced level of $600/MWh (the MPC).

Selected steps are described in more detail below.

2.1.2 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[13], 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.

In our 2024 Price Trends modelling, we modified the bidding behaviour of selected technology types based on historical bidding patterns to simulate real-world pricing dynamics more accurately. However, as our horizon shifts forward each year and the capacity mix in the NEM moves to more renewables and batteries, historical bidding behaviour will be less representative of future bidding dynamics. In consultation with other modellers in the industry, we have modified our approach this year such that we run our PLEXOS model using SRMC-based bidding and then simulate real-world price volatility through post-processing. This extends the approach we used last year, with the key difference being that: this year we generate almost all the price volatility through post-processing, whereas last year we did so through a combination of bidding behaviour and post-processing.

We treat batteries the same as in our 2024 modelling, in that they do not have an explicit bidding function, but rather are 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 temper the effects of perfect foresight and ensure batteries do not discharge when prices are $0/MWh, or cycle when the daily price spread is too low.

The benefit of this SRMC-based approach is that our spot price outcomes are less dependent on our view of future bidding and are more influenced by fundamental factors such as the changing cost of supply and the supply-demand balance. The approach taken to post-processing, called the ‘price volatility adder’ is explored in more detail below.

2.1.3 Price volatility adder

The dispatch and price outcomes generated from our base PLEXOS model described above produce a price series that reflects the changing short-run cost of supply, but does not necessarily replicate the price volatility that occurs in the real world. There are a number of factors that explain this:

- Our base model produces dispatch outcomes based on short-run marginal cost, whereas in the real world generators bid based on a range of other factors, not necessarily to only recover their SRMC.

13 Note that AEMO also use a time-sequential bidding behaviour model in their modelling for the ISP, as outlined in the ISP Methodology document, however this model is not published.

- PLEXOS is a perfect foresight model, which means that there are no “unexpected” shocks to the system.
- The ISP model (which we use as a basis) uses approximate constraints rather than the thousands of detailed constraints in the NEM – given that the ISP produces a long-term planning outlook. This reduces the variability of dispatch outcomes and prices.
- It is very difficult to capture dynamic bidding strategies for generators that operate within portfolios, that are responsive to potential retail exposures of major gentailers, or the need to recover their fixed costs during periods of supply scarcity.[14]
- 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 very high 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 historical 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 a distinct relationship between reserve margin and the logarithm of prices, with reserve margins between ~150% and ~30% showing a clear linear relationship to log price, and reserve margins less than 30% showing a much steeper linear relationship.

In 2024, we used two linear regression models to fit these curves, however in this year’s modelling we simply use a rank based model of the empirical data and apply this to our calculated reserves in PLEXOS:

- This model works by simply taking the calculated reserve margin and returning a price which corresponds to that margin in the empirical data
- Where there is no historical price for the specific reserve margin then we interpolate between the reserve margins on either side
- We found that using the empirical distribution is an improvement over the linear regression model as it captures more of the extreme variability in prices seen in the real world, rather than smoothing them out using a line of best fit.

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

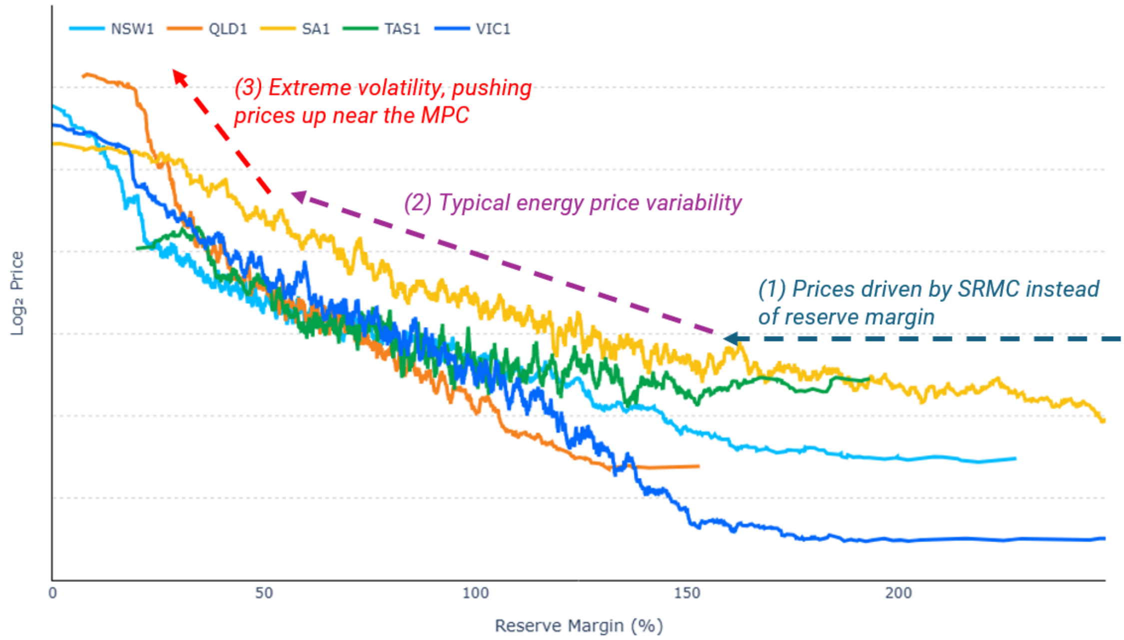
We note that this method assumes that the historical relationship between reserve margin and prices will continue into the future, but we take the view that this is a reasonable assumption given the relationship is so strong, and since this approach is technology independent.

The below chart shows the historical relationship between reserve margin and log prices that is used as the empirical distribution in our post-processing. This shows three distinct relationships:

1. A flat line up to reserve margins of around 150% where reserve margin does not predict price; this represents periods where there is enough competition in the market such that prices are set by the short-run cost of supply only
2. A sloped linear trend between a reserve margin of ~150% and ~30%; this represents typical daily energy price variability
3. A steeper sloped linear trend between ~30% and ~10%; this represents scarcity pricing and extreme volatility where there is very limited spare capacity in the market, driving prices up towards the market price cap

Note that this data has been collated by analysing AEMO's Market Monitoring System (MMS) database from January 2017 to July 2025.

Figure 2.3: Historical reserve margin vs. prices by region (log scale)



Source: Analysis of AEMOs Market Monitoring System (MMS) database from January 2017 to July 2025
Note: Note that this data has been averaged for the purposes of demonstrating the relationship, and as such the Y axis is not shown

The process we used to determine the final spot price in each 30 minute interval was to:

1. Generate a SRMC based spot price by running our PLEXOS model.
2. Determine the empirical spot price by finding the price that corresponds with the modelled reserve margin.
3. Determine the 'volatility markup' by netting off the SRMC based price from step (2) above. This SRMC price is determined by looking at the where the historical relationship between reserve margin and price breaks down; this differs by region but is generally at a reserve margin of about 150%, as shown in Figure 2.3.

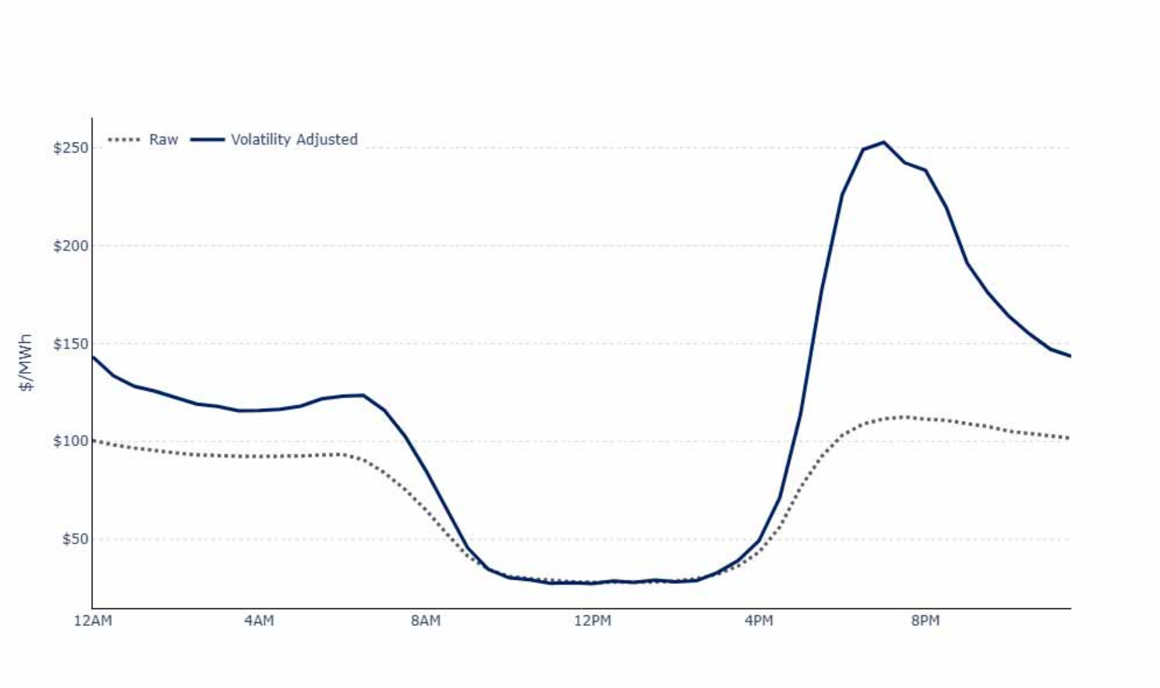
4. Calculate the final spot price by adding the volatility markup to the SRMC based PLEXOS price.

We have ensured the validity of this approach by:

- Testing it with a market modelling consultant to validate the approach
- Performing out-of-sample tests on historical data
- Comparing price duration curves with historical data
- Comparing time-of-day price series with historical data

Figure 2.4 shows the typical impact on wholesale costs after adding in the price volatility uplift.

Figure 2.4: Change in modelled wholesale prices as a result of the volatility post-processing



Note: This chart shows the average wholesale prices before and after volatility adjustment across the entire ten year horizon. Source: AEMC analysis.

2.1.4 Applying the market price settings

The wholesale prices that are generated from our SRMC PLEXOS model and post-processed through our price volatility adder are then adjusted according the wholesale market price settings. Specifically, we adjust our prices to take into account the impact of the following price settings on wholesale spot prices:

- The Market Price Cap (MPC),
- The Cumulative Price Threshold (CPT)
- The Administered Price Cap (APC

Note that the Market Floor Price (MFP) is not included as our model does not produce prices that are deeply negative.

These price settings are scheduled to increase in the first three years of our modelling horizon in accordance to the AEMC final rule[15]on amending these settings following the 2022 Reliability

15 Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap, published 7th December 2023

Standards and Settings review[16]. We have applied this schedule of settings to our wholesale prices, adjusting the values to FY25/26 dollars.

2.1.5 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 2.5: Range of modelled wholesale prices (unhedged) across weather reference years

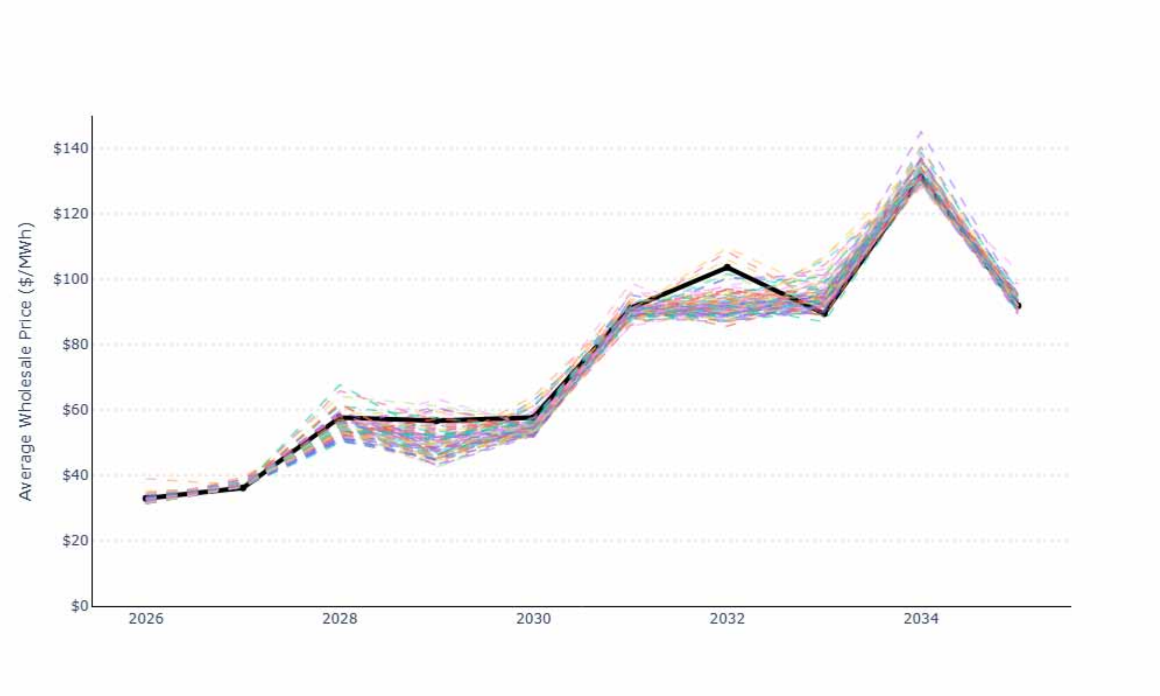
This chart shows the range of volatility-adjusted wholesale prices when we ran the model under each of the 13 different weather reference years. We selected weather outputs from the 2021 reference year to determine the patterns throughout the planning horizon. This reference year was determined to be 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.

2.1.6 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, 100 samples of outage patterns were simulated, based on the reference year 2021.

16 2022 Reliability Standards and Settings Review, published 1st September 2022

Figure 2.6: Range of modelled wholesale prices (unhedged) across 100 outage samples



As shown in Figure 2.6, changing the outage sample can have small-medium impacts on wholesale prices in a particular year.[17] Our initial random seed produced a price series that is within the bounds of the 100 additional outages modelled, so we kept this outage sample as our base case.

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

17 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.

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 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 Default Market Offer prices 2025-26 and the AEMC's Price Trends 2025

	AER's DMO prices 2025-26	AEMC's Price Trends 2025
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	FY25/26 only (1 year)	FY25/26 to FY34/35 (10 years)
Demand	• ISP 2024 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 2025 ESOO central case 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, 2025 ESOO and 2025 IASR
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 75th percentile simulated wholesale electricity costs	• Build up book of contracts over 2-3 years • Include base swaps, cap contracts and base options • Hedging strategy is based on a representative or typical profile, covering average expected PoE10 demand with

	AER's DMO prices 2025-26	AEMC's Price Trends 2025
		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 diagramatically below:

Figure 2.7: Approach to modelling cashflows for base swaps

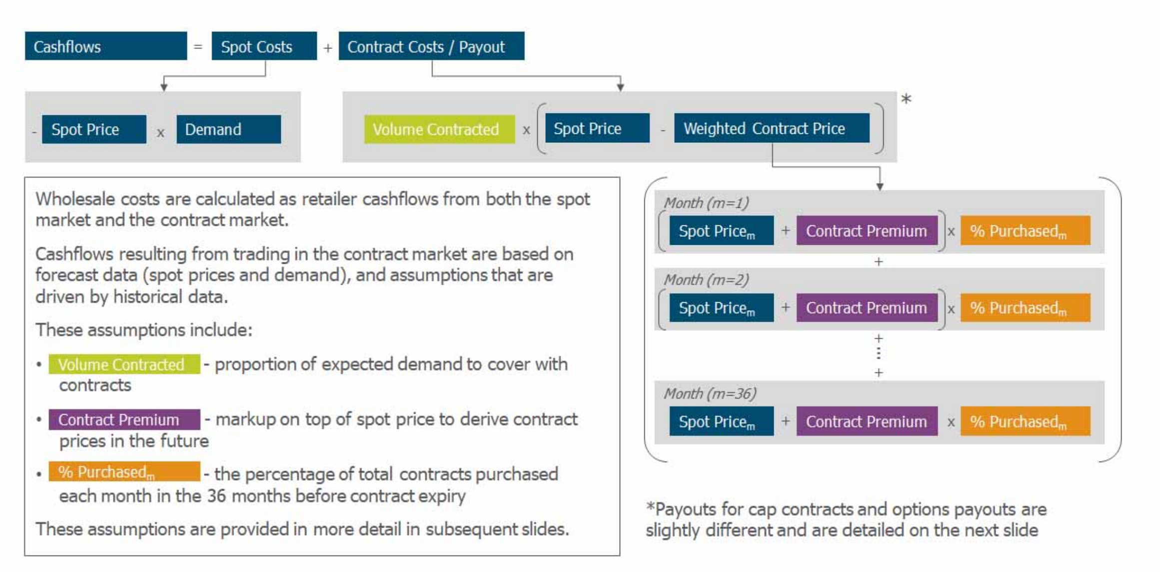


Figure 2.8: Approach to modelling cashflows for caps and options

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 December 2024, excluding 2022) and historical ASX-listed contract prices (base, peak and cap quarterly contracts between Q1 2017 and Q4 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. The introduction of Marinus Link, and the potential conversion of Basslink to a regulated interconnector, could see spot prices in the two regions converge further.
- 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	$3.6	$3.9	9.3%	$6.9
QLD	$4.4	$2.7	25.4%	$5.3
SA	$12.8	$5.1	-	-
VIC & TAS	$6.9	$5.8	9.8%	$5.2

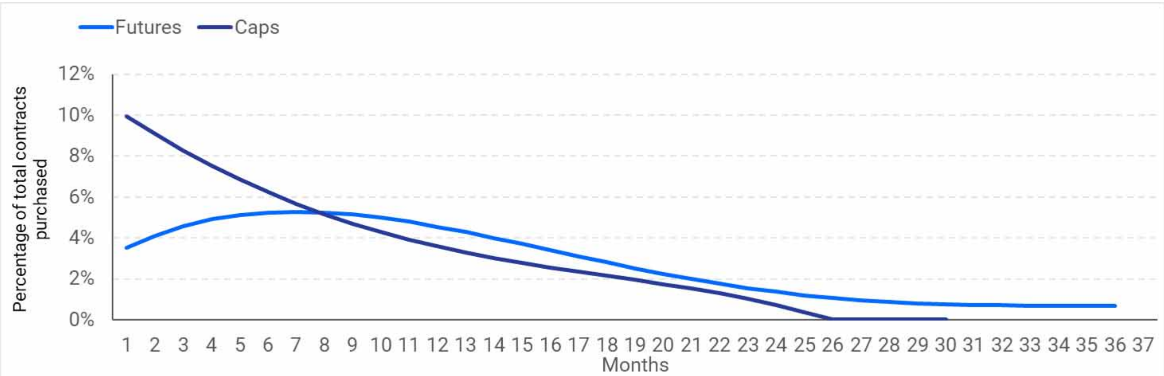
2.2.3 Book build assumptions

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 Q4). 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 2.9: 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 few years

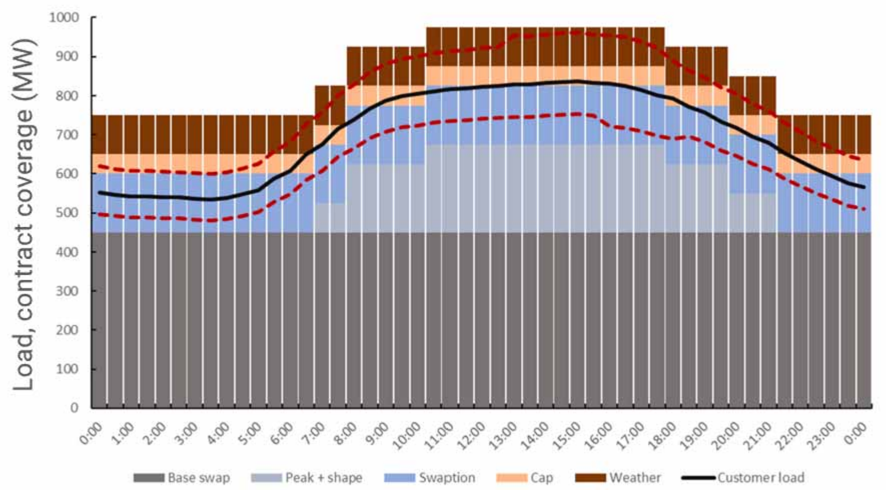
These contracting volumes are an estimate based upon the research outlined below:

- The analysis and indicative hedging strategy described by the 2024 paper 'Derivatives and hedging practices in the Australian National Electricity Market' published in the academic journal, Energy Policy[18]
- 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[19], while the second figure shows an example of the hedged volumes in our model for a single region and quarter.

Figure 2.10: Representative hedging profile



18 Energy Policy, available at https://www.sciencedirect.com/journal/energy-policy

19 Derivatives and hedging practices in the Australian National Energy Market published by Jonty Flottmann, Phillip Wild and Neda Tedorova in July 2023

Figure 2.10 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.

Figure 2.11: Example of hedging profile used in the model (NSW Q3 2028)

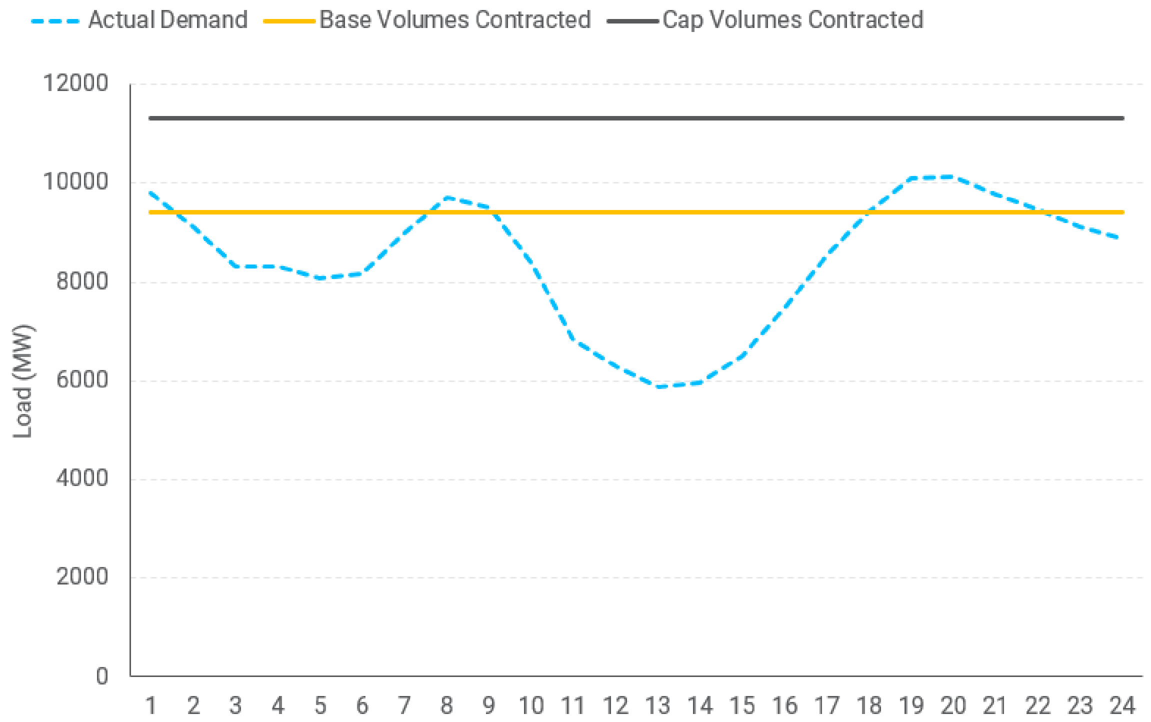


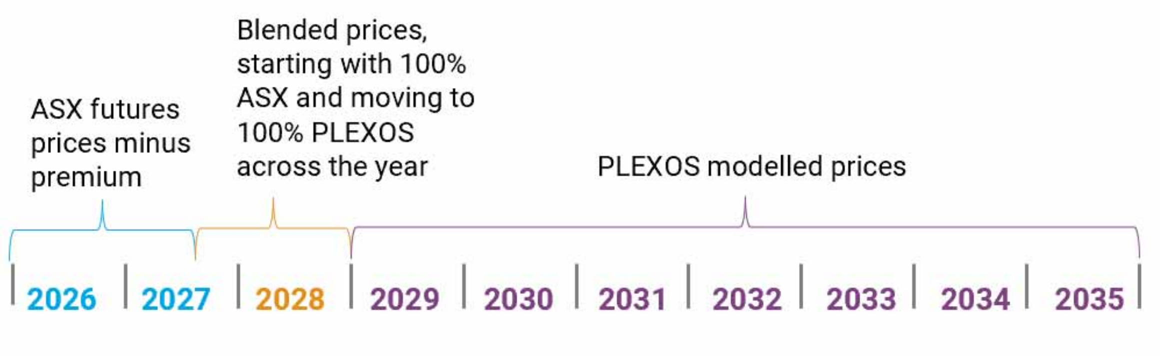
Figure 2.11 shows an example of how load is hedged in our contracting model, where the orange line represents the level of contracting for baseload contracts (purchased through a combination of swaps and options), and the difference between the orange line and the black line represents the volumes of 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[20] 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.

20 Note that the estimated contracting premium is removed from forward contracts, since these contracts are priced slightly above the expected future spot prices: that is, they already include a contracting premium.

Figure 2.12: Where spot prices come from in our wholesale model



2.3 Other costs

At outlined in the beginning of this chapter, 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[21], 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.[22]

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 FY26 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 because these costs typically form a small share of costs. They are also quite volatile year-to-year and so are difficult to project reliably. [23]

21 AEMOs Ancillary Services Payments and Recovery workbooks

22 AEMOs loss factors and regional boundaries workbook

23 For more information about the typical range of costs for these services, please see AEMC, National Electricity Market Reliability & Security Report FY2024 June 2025, Section 3.3

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 publicly available information 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		Basslink	TAS/VIC
SAPN	SA			
TasNetworks	TAS			
United Energy	VIC			

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

- Murraylink: 45% to South Australia and 55% to Victoria[24]
- Directlink: 100% to New South Wales[25]

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

- Basslink: 75% to Victoria, and 25% to Tasmania, in line with its regulatory proposal to the AER.[26]
- Marinus Link: We have accounted for the concessional finance benefits being provided by the Australian, Tasmanian and Victorian Governments[27], and Marinus Link's proposal to commence recovering costs from customers from the beginning of its second regulatory period.[28] The remaining costs are allocated 72.4% to Victoria, and 27.6% to Tasmania[29].

To summarise our approach, we calculated annual revenue requirements using the building block method adopted by the AER.[30]

- 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)[31], 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.

26 AER (2025), AER consults on draft decision for Basslink's transmission revenue determination, Media Relase, 12 September 2025

27 CEFC (2025), CEFC to invest in visionary Marinus Link project in largest-ever transaction, Media Release, 3 September 2025.

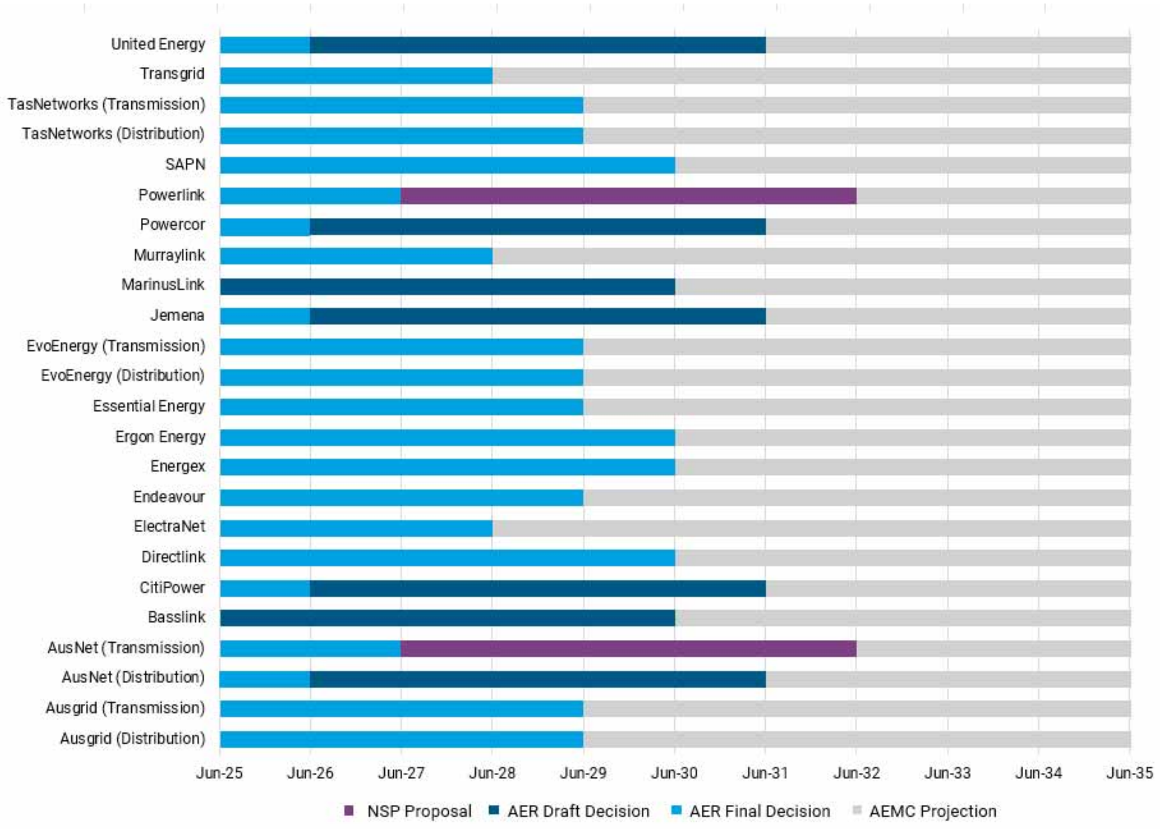
28 Marinus Link (2025), Revised Revenue Proposal Stage 1–Part B (Construction costs), Submission to the Australian Energy Regulator, July 2025, p.85.

29 Marinus Link (2025), Revised Revenue Proposal Stage 1–Part B (Construction costs), Submission to the Australian Energy Regulator, July 2025, p.88

30 More detail on the AER's approach is contained in its State of the Energy Market 2025 report

31 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.

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



Source: AEMC

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).[32] 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.

32 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.

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, AEMO's Electricity Networks Options Report (ENOR), networks' Regulatory Information Test for Transmission (RIT-T) documents, 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 assets have a useful life of 32 years and apply straight-line depreciation.[33] 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 $2025-26 dollars. These are:

- Return on capital and debt
- Return of capital (depreciation)
- Operating expenditure
- Revenue adjustments
- Net tax allowance

33 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.

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, except for Marinus Link, as outlined in the limitations table in chapter 8. For other 'WACC' variables – e.g. the value of imputation credits – we adopted the parameters in the AER's most recently published WACC methodology.[34]

Table 3.2: Key WACC inputs adopted in Price Trends modelling

Parameter (For all years of the outlook unless noted)	Price Trends 2025 Value	Price Trends 2024 Value
Nominal pre-tax cost of debt	4.66% (2025-26)	4.65% (2024-25)
Nominal post-tax return on equity	7.97% (2025-26)	7.91% (2024-25)
Risk free rate	4.25% (2025-26)	4.19% (2024-25)
Gearing	60%	60%
Corporate tax rate	30%	30%
Gamma (value of imputation credits)	0.57	0.57

Source: AER. 2023. Rate of Return Instrument: Explanatory Statement

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. 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.

34 AER, Rate of Return Instrument: Explanatory Statement, 2023

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, Basslink 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.

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 2025-26 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.[35]

35 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

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 (standard control services) Pricing Models.[36] 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	56%
CitiPower	31%
Endeavour Energy	57%
Energex	54%
Ergon Energy	49%
Essential Energy	56%
Evoenergy	48%
Jemena	48%
Powercor	50%
SAPN	53%
TasNetworks	63%
United Energy	53%

Source: 2025-26 Annual Pricing Model for each DNSP, submitted to the AER

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.

36 For an example of the annual SCS pricing models submitted to the AER

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.

Table 3.4: DNSP capex to RAB ratios

DNSP	Capex as a % of RAB
Ausgrid	4%
Ausnet	5%
CitiPower	6%
Endeavour Energy	5%
Energex	3%
Ergon Energy	4%
Essential Energy	6%
Evoenergy	6%
Jemena	7%
Powercor	6%
SAPN	7%
TasNetworks	7%
UnitedEnergy	7%

Source: AEMC Analysis

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)
- Operating expenditure

- Revenue adjustments
- 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). 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 (25-26, $m)	Description	Cost estimation method
ACT Large scale Feed-in Tariff (FiT) Scheme	42.8 (2024-25)	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. Note, although this scheme is technically not a jurisdictional scheme, the net costs or payments are still recovered by the DNSP from retailers in the ACT.
ACT Energy Industry Levy	1.8	Levy to fund the ACT's national and local energy industry regulatory costs.	Costs held constant in real terms.

Scheme	Cost (25-26, $m)	Description	Cost estimation method
ACT Utilities Network Facilities Tax	10.8	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	14.1	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	493.2	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	304.8	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	145.6	Scheme costs associated with legacy support scheme for solar PV (photovoltaic). 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	0.9	This amount recovers the contribution of the Queensland government to funding the AEMC.	Costs held constant in real terms.
QLD Electrical Safety Office (ESO) levy	6.0	This amount recovers the contributions that Queensland DNSPs need to make to the electrical safety regulator.	Costs held constant in real terms.
SA PV Feed-in Tariff Scheme	80.6	Scheme costs associated with legacy 44c/kWh support scheme for solar PV. The scheme ends on 30 June	Costs held constant in nominal terms until scheme expiry date.

Scheme	Cost (25-26, $m)	Description	Cost estimation method
		2028.	
SAPN Small Compensations Scheme	6.0	The Small Claims Scheme is designed to provide small customers with small claims a low cost and effective way to obtain compensation for damage to their property without needing to demonstrate that SA Power Networks is at fault, negligent or has acted in bad faith.	Costs held constant in real terms.
Energy Safe Victoria Levy	25.9	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.
ESC licence fee	3.3	The licence fee that Victorian DNSPs pay to the Victorian Essential Services Commission.	Costs held constant in real terms.

Source: 2025-26 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.

Note that we have not included costs associated with South Australia's Firm Energy Reliability Mechanism (FERM). Unlike the schemes above, the costs of the FERM are recovered to consumers through Transmission charges, rather than Distribution charges. While procurement targets and a cost recovery mechanism from network customers have been set for the scheme, for Price Trends 2025 we are not aware of any publicly available data to project the costs of the scheme, with auction results for the first round of the scheme not scheduled to be released until 2026.

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.[37]

The Roadmap[38] 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,

37 More information about the AER revenue determination process for the recovery of Roadmap scheme costs from DNSPs

38 Further information on the NSW Electricity Infrastructure Roadmap

we modelled these costs based on the building block approach we adopted for TNSPs as described in section 3.2 earlier. 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 treating them as if they were TNSP augmentation capital expenditure, including the flow-on costs to other building blocks such as tax and opex. For projects where the AER has provided revenue requirements as part of regulatory determinations, including the Hunter Central Coast REZ and CWO REZ, we use these revenue requirements where available.

- **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.[39]

We have only included projects awarded an LTESA in Tender Rounds 1-5, since detailed information on the outcomes of Tender Rounds 6 and 7 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.[40] 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.

39 AEMO market briefing notes
40 See, for example, Table 4 of the Market Briefing Note for Tender Round 4

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.

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

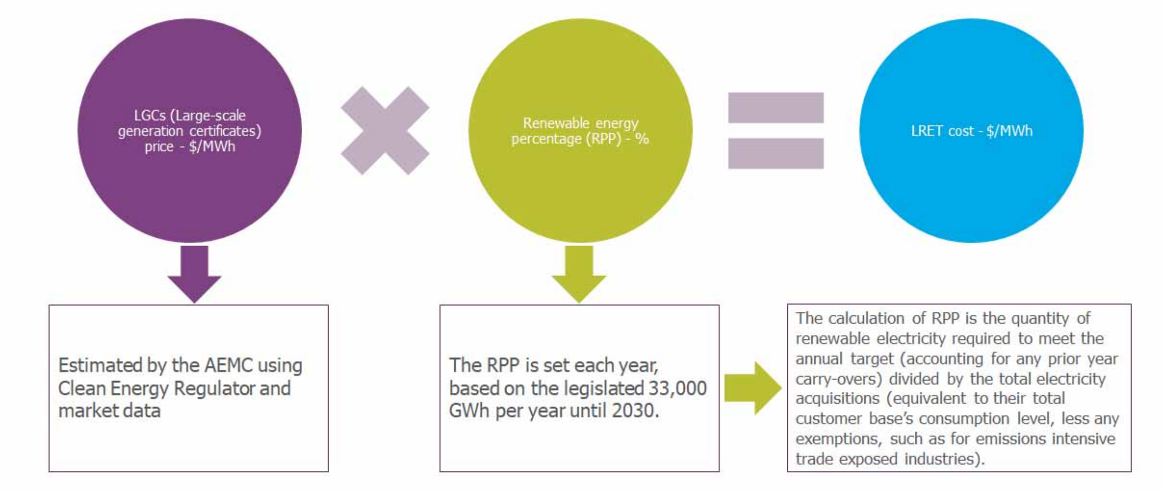
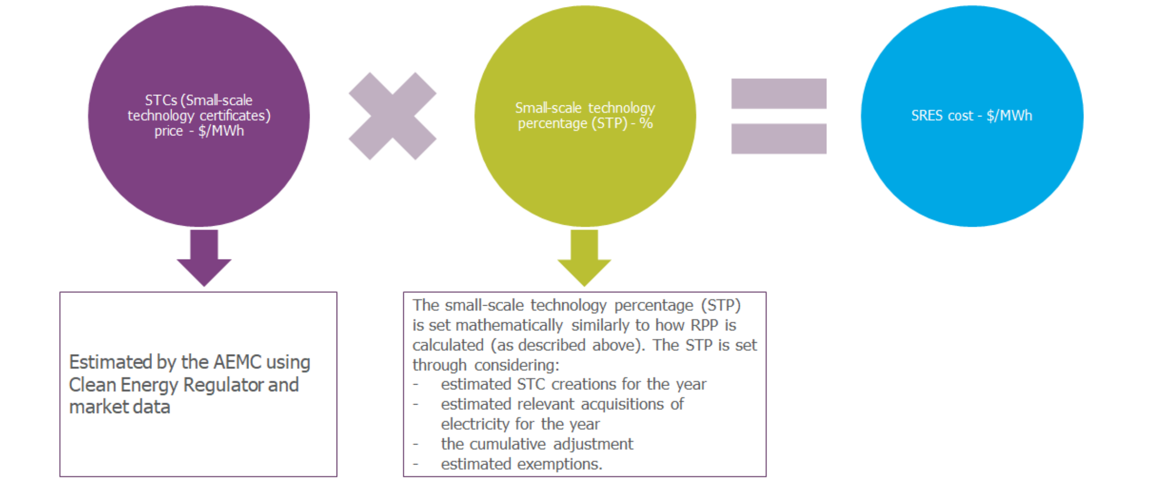


Figure 4.2: SRES cost calculation methodology



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.[41] 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 2025 ESOO. 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.[42] 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 2025 ESOO for forecasts of POE10 peak demand.

41 More information on the NSW energy savings scheme

42 More information on the NSW 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.[43] 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 2027. Post-2027, we assume that the number of VEECs to be surrendered increases linearly, consistent with the trend between 2026 to 2027. 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.[44] 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.[45] 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 2025 and 2026, 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

43 More information on the Victorian energy upgrades program

44 More information on the SA retailer energy productivity scheme

45 More information on the ACT 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).[46]Finally, we combined these figures with electricity demand forecasts from AEMO's 2025 ESOO to produce EEIS costs.

46 ACT Government, Energy Efficiency (Cost of Living) Improvement (Energy Savings Contribution) Determination 2025 (DI2025-259)

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 2024 *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 2024, 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 fluctuated since a peak in 2016-17, and have averaged close to 4% over recent years. Our assumption of a 4% margin partly reflects an expectation that the average over recent years will hold in future. Retail margins set by jurisdictional regulators and the AER (as part of its DMO), for the 2025-26 year, were typically 5-6%.[47] A 4% margin is therefore a reasonable approximation, given 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

47 See, Essential Services Commission (2025), Victorian Default Offer 2025-26, Final Decision Paper, Table 6, page 58, 21 May 2025.

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 2023-2026 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 Household numbers and electricity consumption

This chapter explains how we projected the number of households in the NEM to calculate average household energy costs, and projected residential electricity consumption to calculate average electricity prices.

6.1 Number of households

To calculate average household energy costs (that is, the energy wallet), we need to divide our electricity and gas cost estimates by a projection of residential customer numbers (or household numbers).[48]

To do this, we project customer numbers at the DNSP level. For each DNSPs, we source the current year's customer numbers from each DNSP's 2025-26 Annual Pricing Proposals. 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 Residential electricity consumption

After we calculate each element of electricity costs that are paid by residential consumers, we need to divide these costs by a projection of residential electricity consumption in each year, to derive average residential electricity prices.[49]

We use AEMO's latest Step Change projections for 'Residential Grid Demand' as a basis, and then make three adjustments to project households' aggregate billed electricity consumption.

First, AEMO's projections of Residential Grid Demand include all Rooftop PV output that is produced by households. However, some of this PV output is consumed 'behind-the-meter' by the household. To net off the PV output that is consumed by the household, we took the following approach:

- Each DNSP provides the amount of rooftop PV output that is exported annually, as part of the Regulatory Information Notices that each DNSP submits to the AER. We collected the last 5 years of available RIN data – for Price Trends 2025, these are the years 2019-20 to 2023-24.
- We then used historical ESOO publications to provide an estimate of total rooftop PV output for these 5 corresponding years, for each region in the NEM.
- We used these two data sources to calculate the average share of rooftop PV that was consumed by households. This share can vary somewhat year-to-year due to a variety of factors, such as differences in weather conditions.
- Going forwards, we assume that the share of rooftop PV output that is consumed 'behind-the-meter' remains constant, as rooftop PV installed capacity increases over the outlook. This assumption balances two competing factors. On the one hand, as households electrify and purchase Consumer Energy Resources (CER), the amount of electricity they consume will

48 Because we estimate the average distance driven by a household, and therefore their fuel consumption remains constant, petrol costs are in 'person-household' terms. As outlined in chapter 7, we project the uptake, or switching, to an Electric Vehicle based on the projections developed by AEMO as part of the 2025 IASR.

49 Wholesale electricity purchase costs are modelled on a per unit basis, so these costs are projected in average price terms.

increase and, all else equal, they should be able to consume more of the solar output they produce. On the other hand, over time, rooftop PV installations have tended to increase in size, which increases the amount of PV output that is exported to the grid.

Second, AEMO's demand forecasts model EV load separately, and do not separately identify the EV load attributable to residential or commercial EV charging. However, AEMO's detailed EV workbook, which is produced as part of its Inputs, Assumptions and Scenarios Report (IASR), provides a breakdown of residential vs commercial EV charging. When calculating average residential electricity prices, we used AEMO's projections of the total forecast electricity demand from EV charging, and multiplied this by the projected share of EV demand attributable to residential EV charging at home. When calculating average household energy costs (i.e. the energy wallet), we also capture AEMO's projections for residential EV charging at public EV chargers.

Third, for the first year of our outlook, each DNSP provides a projection of residential electricity consumption as part of their annual pricing proposals to the AER. We base our first year demand projections off these DNSPs projections. In subsequent years, we then use AEMO's ESOO projections to calculate the change in residential demand – with the adjustments described above for rooftop PV output consumed behind-the-meter and residential EV charging – to escalate our demand projections.

7 Energy Wallet methodology

7.1 Why we are examining the energy wallet

One of the most notable changes occurring in the Australian economy as part of the transition to net-zero is the electrification of appliances and transport. For example, electric vehicles (EVs) now account for over 12% of all new car sales according to the Electric Vehicle Council's 2025 State of Electric Vehicles report, while almost 1.9 million small-scale solar and heat pump hot water systems have been installed according to the Clean Energy Regulator's Small-scale Installation Postcode Data. Household electrification is expected to accelerate over the medium term, with AEMO's 2024 ISP forecasting that residential electricity consumption attributable to appliance and vehicle electrification will rise from ~0.4 TWh in 2024 to ~26.1 TWh in 2034.

We developed three models to examine the impact of forecast electrification, on aggregate, and the impact of specific electrification actions on the financial position of Australian households:

- The **aggregate household energy wallet model** tracks the mean household's energy cost as the aggregate level of residential electrification evolves as projected by AEMO.
- The **reference household energy wallet model** estimates the impact of discrete electrification actions on a reference household's energy cost.
- The **electrification payback model** estimates the number of years before discrete electrification actions, undertaken by a reference household, pay for themselves from the ongoing cost savings.

An overview of these models and their key inputs are shown in Table 7.1.

Table 7.1: Overview of electrification models, by key inputs

	AEMC electricity price projections	AEMO electrification projections	Household energy sub-load profiles	Upfront and ongoing costs
Average household energy wallet model	Yes	Yes	No	No
Reference household energy wallet model	Yes	No	Yes	No
Electrification payback model	Yes	No	Yes	Yes

7.2 Average household energy wallet

The average household energy wallet model captures an average household's annual energy cost as residential electrification evolves as projected by AEMO. A household's energy cost can be broken down into three categories:

- Electricity cost,
- Gas cost, and
- Petrol (or diesel) cost.

The average household energy wallet model shows that, as households electrify gas and petrol assets, their electricity consumption will rise, but their gas and petrol consumption will fall.

7.2.1 Vehicle electrification

Households that replace internal combustion engine (ICE) cars with electric vehicles (EVs) save on petrol costs but consume more electricity through EV charging. To estimate the average energy cost savings as households gradually switch owning an EV, we:

- Use AEMO's step change demand projections to derive the proportion of households with, or without, an EV.
- Project the petrol costs faced by ICE owners, and the amount of petrol consumed by these households.
- Overlay our electricity price projections to measure average electricity costs.

These steps are explained below.

Annual fuel costs associated with owning an ICE vehicle were derived using data from ABS (2018) *Survey of Vehicle Use, Sub-Annual, Table 4, Passenger Vehicles*. Households were assumed to either own one EV or one ICE car. This car would be driven the average amount each year, based on the ABS data.[50] We then used the Australian Automobile Association's Real-World Testing Program estimates to estimate fuel consumption, per kilometre of travel, weighted for small, medium and large vehicles for each region in the NEM. To project fuel prices, we use a simple forward projection of fuel prices based on ACCC (2025) *Quarterly report on the Australian petroleum market – June quarter 2025*.

Our projections of residential electricity demand include the EV load from vehicles charging 'at home'. For the energy wallet, we also need to include the EV load from public EV charging. Estimates of public charging demand were obtained from AEMO's (2025) *2025 IASR EV workbook*.

Because the focus of the aggregate model is on the *energy costs* faced by household's on average, it does not account for the non-energy costs associated with owning an EV compared to an ICE vehicle. These include – but are not limited to – upfront purchasing costs, insurance premiums, road user charges, servicing costs and depreciation. These ongoing costs are considered in the electrification payback model described below.

7.2.2 Gas appliance electrification

Switching to electric appliances saves on gas costs but also results in additional electricity costs. 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, and
- Gas customers also incur a service charge, which will change over time based on the number of customers connected to the gas network.

In our analysis, wholesale 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 using a combination of data sources including Regulatory Information Notice (RIN) data for regulated gas distribution networks, and DCCEEW Australian Energy Statistics, depending on data availability.

50 In Price Trends 2024, we used the 2021 ABS Survey data to derive distance travelled. However, as the amount travelled by households over this period was impacted by COVID lockdowns, we have changed our assumption to use the previous 2018 survey as it more likely to be representative of the distance that the average household drives in a typical year.

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 will electrify. [AEMO (2024) *Gas Statement of Opportunities*] (GSOO) provides a forecast of the reduction in residential gas consumption that is attributable to electrification. These, with the household consumption figures, as mentioned above, were used to forecast the number of gas customers who will electrify. To project gas service charges, we then used RIN data 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 projected the gas asset base (the RAB) projecting forward the recent trend in capex spending and straight-line depreciation. The gas network asset base, which was projected for each gas network based on depreciation and capex, are 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.

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

7.3 Reference household energy wallet

The reference household energy wallet model is used to estimate the effect of electrification actions on a typical individual household's annual net energy cost. Electrification actions can be grouped into four categories:

- Appliance electrification, which involves replacing gas space heaters, water heaters, cooktops and ovens with electric equivalents, and disconnecting from a gas distribution network
- Vehicle electrification, which involves replacing a petrol-consuming vehicle with an electric vehicle (EV)
- Rooftop solar installation, and
- Battery installation.

A household's net energy cost is defined as

- The sum of their electricity usage and supply charges, gas usage and supply charges, and petrol cost,
- Less any electricity export revenue from rooftop solar generation.

While the average household energy wallet model captures the average household energy expenditure for each NEM region, the reference household energy wallet model allows for greater flexibility in the type of household modelled. This flexibility includes:

1. What types of CER a household installs, and when
2. Where the household lives
3. What type of household they live in (e.g. dwelling size, type and thermal efficiency)
4. How they consume electricity (e.g. number of occcupants), and
5. What prices, and price structures, they face for electricity, gas and petrol

For the Price Trends 2025 report, we have modelled a reference household that:

1. Makes the modelled electrification actions today.

2. Lives in the capital city of each NEM region (or the average of capital cities when we present NEM-average results).
3. Lives in an averaged-sized house with 3-star energy efficiency, with an asset configuration consistent with a typical house in that region of the NEM. This is described in more detail below.
4. Consumes electricity consistent with a 3-person household.
5. Faces electricity prices consistent with our Price Trends projections, as described below.

The model we have developed has the flexibility to consider different configurations - for example, the annual total energy cost incurred by a 4-person house with a 6-star energy rating located in Adelaide that has only electrified their space heating and has installed a rooftop solar system. However, in calculating our Price Trends estimates, we have used energy costs for the capital city in each region as the basis for our projections. If there is interest from stakeholders, this is something we could consider in future Price Trends reports.

We have developed this reference approach to align the assets, and electrification actions, taken by our modelled household to the upfront and ongoing costs they would incur in the electrification payback model, described below. That is, this year's reference household energy wallet model captures a household's entire electrification journey (from no electrification to full electrification, which includes solar and battery installation), while last year's model only captured part of this journey (from the electrification stage of an average household to electrification solar installation only).

Since households are at different stages of their electrification journey, the average household, which will have installed fractions of different energy assets rather than whole numbers of them, is not a suitable subject for payback period analysis, as outlined in Section 6.4.

It is worth noting that prices modelled in the reference household energy wallet model and the electrification payback model include GST, as this is a real-world cost borne by households taking electrification actions.

The following sub-sections outline how we projected energy costs in this model. They outline, in turn, our approach for calculating: energy prices; the electricity or gas consumption for home appliance usage; the EV or petrol consumption for vehicle usage; the solar output if they install rooftop PV; and home battery operation.

7.3.1 Energy prices

Average standing offers across major retailers were used to provide

- Electricity and gas usage rates ($/kWh and $/MJ),
- Electricity and gas supply charges ($/day), and
- Electricity feed-in rates ($/kWh).

Electricity usage rates are time-of-use rates. For Tasmania, where retailers do not make standing offers, market offers were used instead.

Offers were sourced from

- The Australian Energy Regulator's Energy Made Easy website.
- The Victorian Department of Energy, Environment and Climate Action's Victorian Energy Compare website.
- Solstice Energy's pricing webpage.

- Petrol prices were sourced from the ACCC (2025) *Quarterly report on the Australian petroleum market – June quarter 2025*.

Projected electricity usage and supply charges were computed by escalating current charges by this year's Price Trends residential electricity price projection. Forecast gas supply charges were computed by escalating current charges by forecast gas network charges that were modelled in the aggregate energy wallet model, which use gas distribution network data on capex, regulated asset bases, and forecast customer numbers. Future petrol prices were held constant in real terms.

7.3.2 Home appliance energy consumption

We adopted a bottom-up approach to model home appliance energy consumption, based on hourly electricity and gas consumption profiles for each month and NEM capital city.

Intraday profiles of energy consumption for space heating, space cooling, cooktop heating, oven heating, lighting, and plugs were sourced directly from or derived using methods outlined in NatHERS (2025) *Whole of Home Calculations Method*. The intraday profile for water heating was sourced from Australian Building Code Board (2022) *NCC 2022 Update: Whole-of-Home Component – Appendix 2*.

These profiles were used to distribute annual or monthly energy consumption figures across the 24 hours of an average day in each month. Annual energy consumptions for cooktop heating, oven heating, lighting, and plugs were derived using methods outlined in NatHERS (2025). For other energy services, annual or monthly energy consumption was calculated as energy output divided by energy efficiency.

Annual energy consumptions for space heating and cooling were derived using:

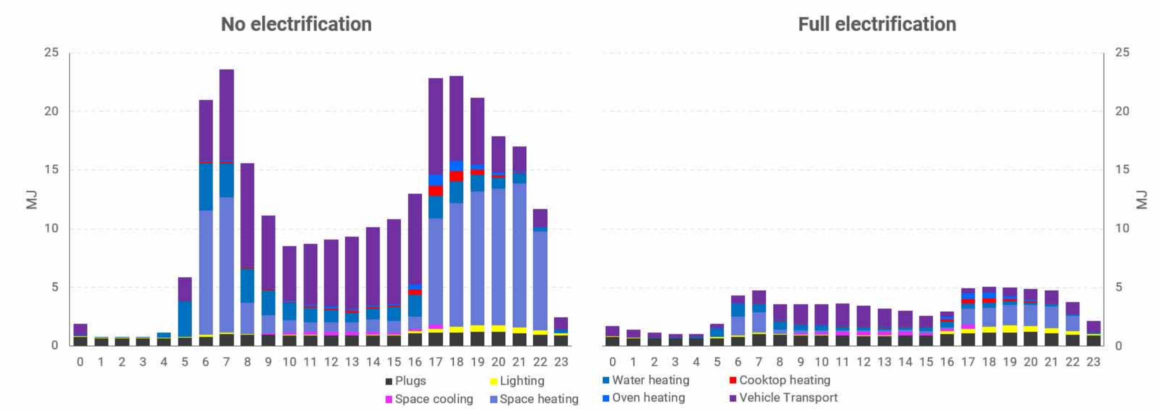
- Annual heating and cooling outputs per square metre for a Class 1 house, by energy star rating and city. Data was sourced from CSIRO (2025) *Australian Housing Data* and NatHERS (2022) *Star Bands*.
- Data on the conditioned floor areas of a dwelling from CSIRO (2025).
- For regions other than Victoria and the ACT, a 3-star gas room heater's coefficient of performance (COP), calculated according to methods outlined in NatHERS (2025).
- For Victoria and the ACT, a 3-star gas ducted heater's COP, calculated according to methods outlined in NatHERS (2025). This accounts for 15% duct losses.
- A Reverse Cycle Air-Conditioner's (RCAC's) COP, calculated as an average across a sample of models sold by online retailers.

Annual energy consumption for water heating was derived using

- Annual hot water energy output for a Class 1 house in each city, calculated according to methods outlined in NatHERS (2025).
- A 5-star gas instantaneous hot water system's COP in each city, calculated according to methods outlined in NatHERS (2025).
- A heat pump hot water system's COP in each city, calculated according to methods outlined in NatHERS (2025).

Figure 7.1 shows how the household energy wallet model stacks sub-loads to form a total energy load, and how a household's total energy usage falls when it fully electrifies. That is, it shows how electrification increases a household's energy efficiency.

Figure 7.1: Hourly energy usage



Note: MJ; Average day in March; 3-person house with a 3-star energy rating in Melbourne; the petrol energy usage profile over the day is illustrative only and does not impact energy wallet results.

7.3.3 EV load and petrol consumption

Monthly energy consumption for vehicle transportation was derived using the kilometres travelled in each city and month, sourced from ABS (2018) *Survey of Vehicle Use, Sub-Annual, Table 4, Passenger Vehicles*.

Intraday profiles for EV charging were sourced from AEMO (2025) *2025 IASR EV workbook*, which provides information on:

- 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., unscheduled charging, daytime charging, nighttime charging), and whether it is a weekend or weekday, and
- 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 2025–26 figures. For simplicity, we assumed that this profile is constant across all forecast years. As a robustness check, 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 unscheduled charging profile. Both alternative profiles were also calculated as weighted averages for the 2025–26 year, and held constant over the 10-year outlook.

Petrol consumption was calculated monthly for each NEM city, based on the average fuel efficiencies for mid-sized petrol-consuming and electric vehicles, using the Australian Automobile Association (2025) *Real-World Testing Program* data.

7.3.4 Rooftop solar output

Households can also reduce electricity costs if they install a rooftop solar or battery system. To project the electricity cost savings of installing rooftop solar, we:

- Assumed that a household would install a rooftop PV system of 10kW, consistent with recent installation trends[51]
- 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, as well as 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 U.S. Department of Energy's PVWatts Calculator. The calculator estimates the energy output of rooftop PV systems throughout the world (including Australia).

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, described in the subsections above. 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 total household electricity consumption at any point 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 changed in proportion to the base case electricity price over time.

7.3.5 Home battery operation

We modelled a 15kWh home battery. A household's battery was assumed to have an annual degradation rate of 1.8%, a round-trip efficiency of 85%, and to only charge or discharge up to 85% of its rated capacity, consistent with assumptions made in CSIRO (2024) *Small-scale solar PV and battery projections 2024*. This was operated using either:

- A simple 'solar soaking' behaviour, or
- An optimiser algorithm with perfect foresight, as used in recent AEMC analysis.

For the 'solar soaking' operation of the battery, we assumed:

- The battery first charges from solar generation in excess of a household's gross electricity consumption, and not from the grid.
- Once the battery reaches its maximum allowed charge, any remaining solar generation (i.e., beyond that which satisfies gross consumption and the battery) is exported to the grid.
- The battery is discharged for the household's consumption once solar generation does not fully satisfy gross consumption.

7.4 Electrification payback model

The electrification payback model takes a household's net energy cost calculated by the reference energy wallet model as an input and then adds:

- The upfront costs of purchasing and installing energy assets
- Subsidies for installing energy assets
- Charges for disconnecting from a gas distribution network (if relevant), and

51 For Price Trends 2024, we modelled a 6.6kW system. However, CSIRO (2024) and Clean Energy Regulator (CER) data both suggest the average installed solar system is currently about 10kW.

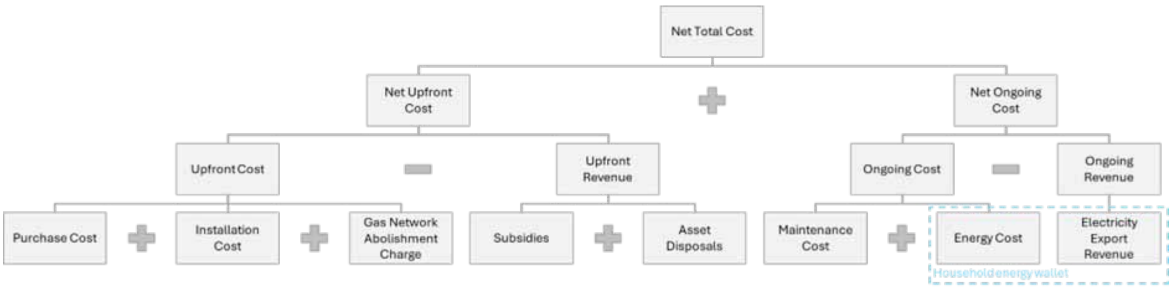
- Maintenance costs from operating energy assets.

The first three of these items are experienced on a one-off, or 'upfront' basis, while maintenance costs are incurred on an ongoing basis.

In addition, if a household electrifies they may also avoid future costs of replacing existing assets. Intuitively, replacing an old gas appliance with a new electric equivalent has a smaller opportunity cost compared to electrifying a brand new gas appliance. As described below, in our model we have adopted a conservative assumption and excluded these future cost savings.

Future cash flows are calculated in real terms, and discounted by 5% per year, so that upfront and ongoing cash flows are combined to give a household's net total cost of owning energy assets in net present value terms, as shown in Figure 7.2.

Figure 7.2: Electrification payback model structure



Source: AEMC

An electrification action's payback period is defined as the number of years before the cumulative net total cost (in present value terms) of the energy asset configuration resulting from the action is lower than the costs of the non-electrified counterfactual asset configuration.

7.4.1 Asset configurations

The household is assumed, in all cities, to start with the following assets:

- 1 x 5-star gas instantaneous hot water system,
- 1 x 60cm gas cooktop,
- 1 x 60cm gas oven, and
- 1 x mid-sized petrol-consuming car.

Additionally, it is assumed that

- Households in Sydney, Adelaide and Hobart start with a 3-star gas room heater in each of their master bedroom, standard bedroom, and main living space.
- Households in Melbourne and Canberra start with a 3-star gas ducted heater for whole-of-house heating.
- A household in Brisbane starts with a 3-star gas room heater only in their main living space, due to Brisbane's relatively warm climate.

It is important to note that the number and size of household energy assets do not impact the quantity of energy that modelled households consume, as these are derived from the reference household energy wallet model described above. The number and size of energy assets is modelled to calculate the upfront cost of replacing these assets.

The model assumes that when these initial gas and petrol assets would be replaced by modern energy-efficient electric equivalents:

- Gas room heaters are replaced with RCACs in those rooms
- A gas ducted heater is replaced with RCACs that are installed in both bedrooms and the main living space of a house
- A gas instantaneous hot water system is replaced with a heat pump hot water system
- A gas cooktop is replaced with an electric induction cooktop
- A gas oven is replaced with an electric oven, and
- A petrol-consuming car is replaced with an electric vehicle.

7.4.2 Purchase prices

Purchase prices for petrol-consuming and electric vehicles, rooftop solar systems, and battery systems were averaged across sources online, escalated to FY26 dollars where appropriate, and rounded to multiples of $10.

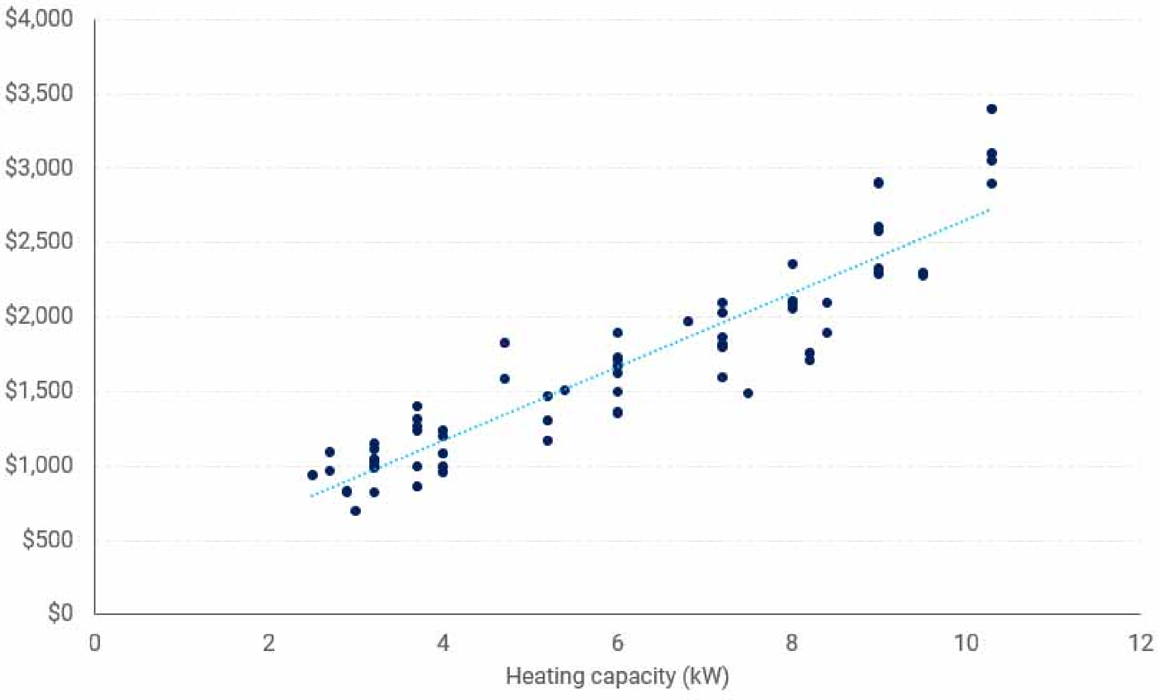
Purchase prices for appliances were estimated using a two-stage process. In the first stage, the relationship between an appliance's size and dwelling size (room sizes in square metres and number of occupants) was estimated based on sizing guides available online. In the second stage, the relationship between an appliance's purchase price and its size was estimated. Purchase prices and sizes were sampled across a range of online retailers for appliance models available in Australia. Linear regressions were then performed on these samples to estimate the relationships between purchase price and size for each of these appliances.

An example of such a regression is shown in Figure 7.3, where a linear relationship between the purchase price and heating capacity of a reverse cycle air-conditioner (RCAC) is estimated using a sample of 69 different models.

Additionally, we estimate a purchase price of:

- $8,000 for a 10kW solar system, consistent with CSIRO (2024) analysis.
- $10,000 for a 15kW home battery, which is broadly consistent with September 2025 data from comparison websites such as Solarquotes.

Figure 7.3: Split-system RCAC purchase price vs heating capacity



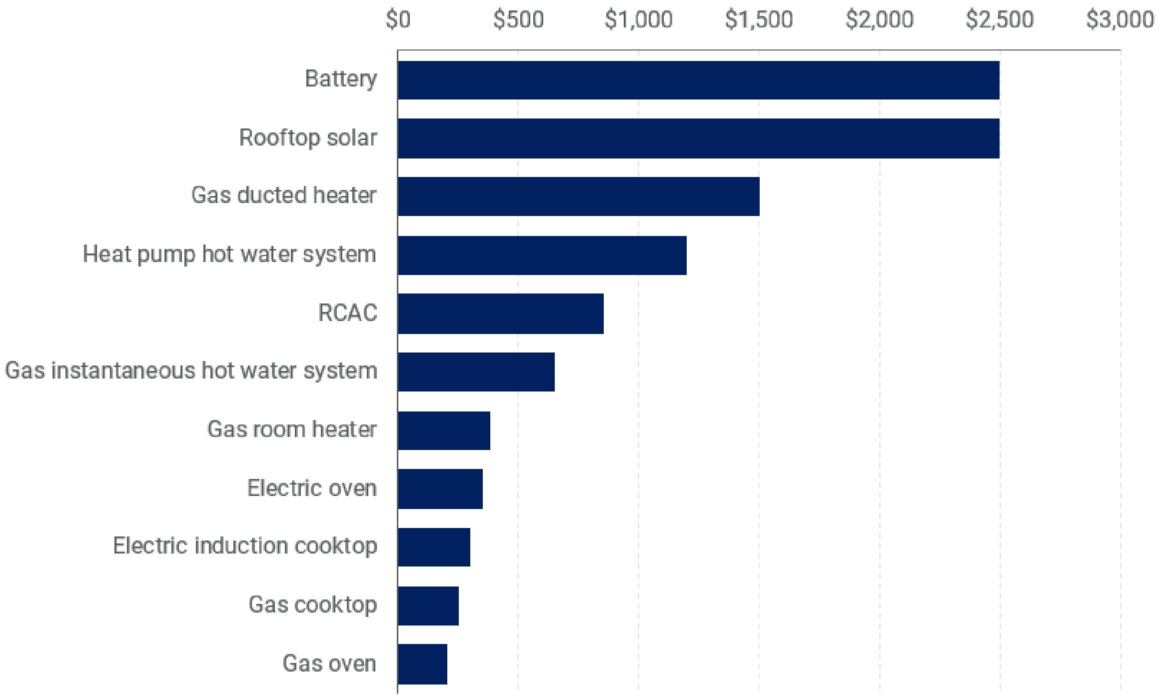
Note: Model purchase prices are averages across retailers; Unbalanced panel dataset of 69 models and 9 retailers

7.4.3 Installation prices

Installation prices for appliances, and rooftop solar and battery systems were averaged across sources online, escalated to FY26 dollar terms where appropriate, and rounded to multiples of $10. The costs modelled are a typical installation cost only, and we note that in some cases, individual households could incur higher costs if this involves complex electrical work or modifications to other parts of their house (e.g. modifications to kitchen benchtops if the size of an induction cooktop does not match the gas one). However, offsetting this, we have made conservative assumptions about the avoided costs of replacing existing appliances (see below).

The installation costs we included are shown in Figure 7.4.

Figure 7.4: Installation costs by asset



Note: Modelled installation prices from various online sources, FY26 dollar terms

7.4.4 Gas network abolishment charges

When a household electrifies all their gas appliances, they may also choose to disconnect from their gas distribution network and avoid paying ongoing gas supply charges. If a household decides to disconnect from gas, they will face a disconnection charge. It is assumed such a household will opt for a permanent disconnection (i.e., abolishment), and that this abolishment will cost the household $250 in all cities. The AEMC is currently conducting rule changes which consider how charges should be set for consumers when they connect or disconnect from the gas distribution network.

7.4.5 Subsidies

Environmental certificates, when created and sold, provide discounts on the upfront cost of purchasing and installing certain assets. The following certificates were modelled:

- Energy Savings Certificates (ESCs) for RCAC and heat pump hot water system installations, under the NSW Energy Savings Scheme (ESS).
- Peak Reduction Certificates (PRCs) for RCAC installations under the Peak Demand Reduction Scheme (PDRS) in NSW. ESCs and PRCs generated by electrification actions were calculated using the NSW government's Safeguard certificate estimator.
- Victorian Energy Upgrade Certificates (VEECs) for RCAC, heat pump hot water system, and electric induction cooktop installations under the Victorian Energy Upgrades (VEU) program. VEECs generated by electrification actions were calculated using the Victorian Essential Service Commission (ESC)'s VEEC Calculator.
- REPS credits for RCAC and heat pump hot water system installations under the Retailer Energy Productivity Scheme (REPS) in South Australia. REPS credits generated by electrification

actions were calculated using the Essential Services Commission of South Australia (ESCOSA)'s eligible activities.

- Small-scale Technology Certificates (STCs) under the federal Small-scale Renewable Energy Scheme (SRES). STCs generated by electrification actions were calculated using the Clean Energy Regulator's Small generation unit STC calculator.

Certificate prices were sourced from Northmore Gordon (2025) *Certificate Prices* and discounted by 10% to reflect administrative fees.

REPS credit values were sourced from ESCOSA (2025) *Retailer Energy Productivity Scheme (REPS) – Annual report 2024*.

The Model also captured the following rebates:

- The Victorian Hot water rebate for heat pump hot water installations under the Solar Homes Program.
- The Victorian Solar panel (PV) rebate under the Solar Homes Program.
- ActewAGL's Heating and cooling upgrade rebate for RCAC installations in the ACT.
- ActewAGL's Electric water heater upgrade rebate for heat pump hot water installations in the ACT.

7.4.6 Avoided costs of replacing existing appliances

The stage at which a gas appliance is assumed to be replaced with a new electric version is a key determinant of electrification payback periods. Consider the following hypothetical example, where it costs $1,000 to replace a gas cooktop with a new version of itself, and the same amount to replace it with an electric induction cooktop. If a household were to perform the first replacement (gas-to-gas) in the same year that they perform the second (gas-to-electric) had they not electrified, then electric induction cooktop installation would have a payback period of 0 years.

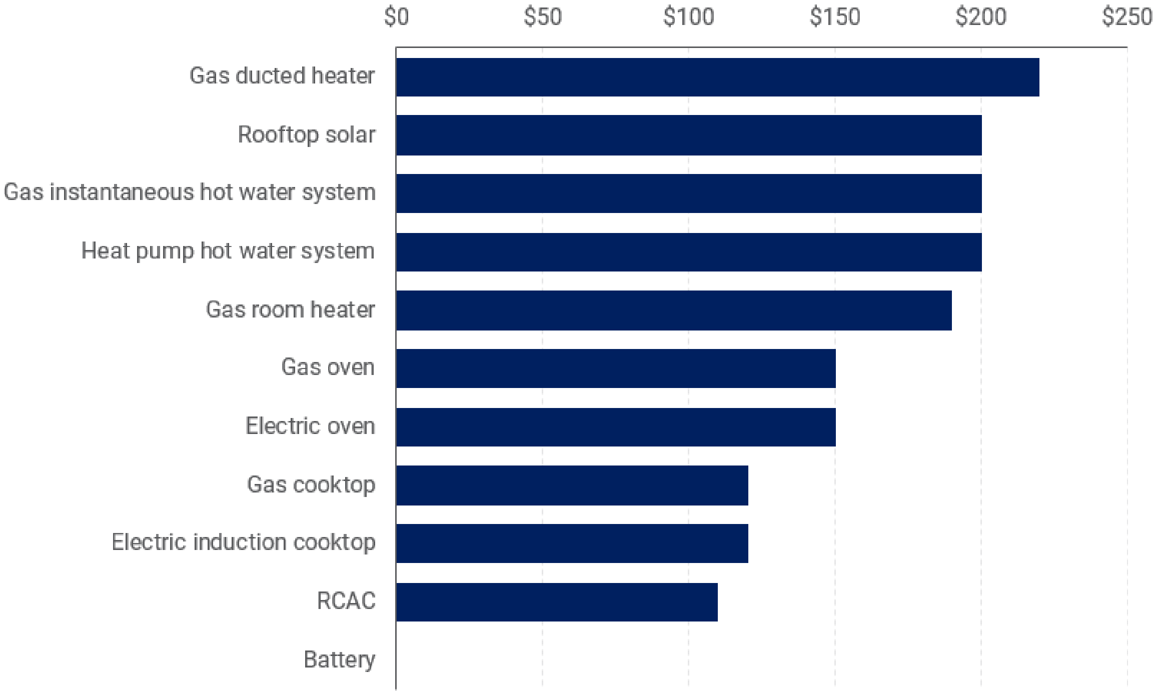
In the Price Trends report, it is assumed that these counterfactual asset replacements occur outside the 10-year model horizon. This makes the payback periods in the report conservative (i.e., longer than if counterfactual replacements occur during the model horizon).

In other words, we ignore the fact that a typical household who electrifies would be replacing an older gas appliance with a new electric equivalent that will last longer before it needs to be replaced compared to the existing asset. Therefore, a household can make additional savings if they are able to sequence when they replace existing assets with electric equivalents when the assets are close to the end of their useful lives and need to be replaced soon.

7.4.7 Maintenance costs

Annual maintenance costs for appliances, rooftop solar and battery systems were averaged across sources online, escalated to FY26 dollar terms where appropriate, and rounded to multiples of $10. These are shown in Figure 7.4.

Figure 7.5: Annual maintenance costs for assets



Note: Annual maintenance costs in FY26 terms.

For vehicles, maintenance costs for EV and ICE vehicles were calculated using [U.S. Department of Energy data] on scheduled maintenance costs per mile, converted into Australian dollars. Per mile rates were converted into metric equivalents, and multiplied by distances travelled per year.

8 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 8.1: Key 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 a combination of the 2024 Final ISP, and the 2025 ESOO and IASR 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.
Future market developments and Government policy	Our projections are based on current market dynamics and Government policy. Future electricity prices will be impacted by changes in derivative markets, the entry and exit of generators from the market, and changes in Government policy. For example, the NEM Expert Panel is currently reviewing what reforms to wholesale market settings are needed to deliver reliable, competitively priced, safe and secure electricity services.	While the impact on prices will be dependent on the specific market development or policy change, we proxy for the potential impacts of some of the key risks and opportunities as part of our scenario analysis. For example, the impact of changes in contracting costs, or the impact of a faster or slower rate of electrification.
Key assumptions made when modelling wholesale costs		

Key modelling assumption or limitation	Description	Impact on prices
Bidding assumptions + price volatility	Our approach to generating wholesale spot prices relies on a short-run marginal cost bidding approach in the PLEXOS model, combined with a post-processed price uplift to account for real world behaviour and volatility. This methodology is outlined in more detail in section 2.1.	Our approach assumes: • dispatch outcomes in the wholesale spot market are generally driven by short-run marginal cost, though there is additional price volatility on top of this • 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.
Hedging strategy	In our modelling we assume a single hedging strategy that is reflective of a prudent retailer. However, in reality, retailers each have different risk appetites and portfolios, and as such may all have differing hedging strategies.	As our approach is based on a 'typical' retailer, we assume that our results reflect roughly average contracting costs and cashflow outcomes, however if risk appetites change in the future then costs passed to residential consumers may be more variable year to year.
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,	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

Key modelling assumption or limitation	Description	Impact on prices
	Newcastle and Wollongong. This constrained operation should be reflected in the battery's bidding behaviour, which we have not adjusted for.	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 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'.	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. 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. We have incorporated concessional finance benefits for Marinus Link, as credible information is publicly available which we can use as a basis for	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.

Key modelling assumption or limitation	Description	Impact on prices
	modelling.	
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 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.	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 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.

9 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 scenarios are summarised in Table 9.1 below.

Table 9.1: Parameters we changed when running scenario analysis

#	Scenario	Description	Period impacted
Supply side			
1	Battery and hydro project delays	Hydro: • Snowy 2.0 delayed 12 months from December 2028 to December 2029 Batteries: • All anticipated and new generic battery builds delayed by 12 months	Entire horizon, but the impact is more significant from FY27 to FY2031
2	Wind and transmission connection delays	• Buildout of all new generic wind resources in each renewable energy zone is delayed by 12 months (i.e. does not include committed or anticipated projects) • Marinus, VNI West, Humelink, and New England REZ Transmission Link is delayed by 12 months, with associated network costs increased by 30%	Wind delays impact July 2027 to the end of the horizon and major transmission delays predominantly impact September 2028 to July 2031
3	Faster wind and transmission	• Buildout of all new generic wind resources in each renewable energy zone accelerated by 12 months • Marinus, VNI West, Humelink, and New England REZ Tranmission Link accelerated by 12 months, with the associated network costs brought forward one year but unchanged in real terms	FY28 onwards
4	Increased contracting costs	Premiums for purchasing electricity contracts are doubled, but held constant over the horizon	Entire horizon
5	Increased gas prices	Fuel costs for gas generators are doubled over the horizon	Entire horizon, but the impact increases over the horizon
6	Decreased coal reliability	The outage rates of coal plants are increased by 5 percentage points, above what is projected in AEMO's	Entire horizon, but the impact decreases

#	Scenario	Description	Period impacted
		IASR (see below for more details)	towards the end of the horizon once more VRE generation enters the system
Demand side			
7	Faster electrification	Electrification demand is accelerated 12 months ahead of AEMO's projections	Entire horizon
8	Slower electrification	Electrification demand is delayed 12 months behind AEMO's projections	Entire horizon
9	Uncoordinated CER orchestration	100% of EV users charge using the "convenience" charging profile as defined in AEMO's ISP, which is primarily charging in the evening peak	Entire horizon, but the impact increases over the horizon
10	Faster home battery uptake	A 20% increase in home battery installations, above AEMO's projections in the IASR (see below for more details)	Entire horizon
Networks			
11	Higher network interest rates	1% higher interest rates over the next 10 years	Entire horizon, but the impact increases over the horizon
12	Lower network interest rates	1% lower interest rates over the next 10 years	Entire horizon, but the impact increases over the horizon
13	Network CAPEX increase	Network replacement capital expenditure (CAPEX) isdoubled 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. We expanded our scenario analysis to include a decreased coal reliability and a faster household battery update scenarios. Further detail about how these were modelled is as follows:

Decreased coal reliability

- A recent paper by Simshauser and Gilmore showed that coal plant outage rates can increase by up to 10 percentage points from the end of their design life (roughly where NEM coal plants are now) to the end of their economic life.[52] Considering this analysis and the 2025 IASR's reported annual unplanned coal power plant outage rates, we modelled a 5-percentage point increase in both short duration partial[53] and short duration full[54]outages, with long duration outages[55] left unchanged.
- This reflected a substantial increase in the chance of an outage, while still being below the typical outage rates at the end of a plant's economic life.

52 Simshauser and Gilmore (2025), The Counterfactual Scenario: are renewables cheaper?, Centre for Applied Energy Economics & Policy Research: Working Paper Series 2025-07

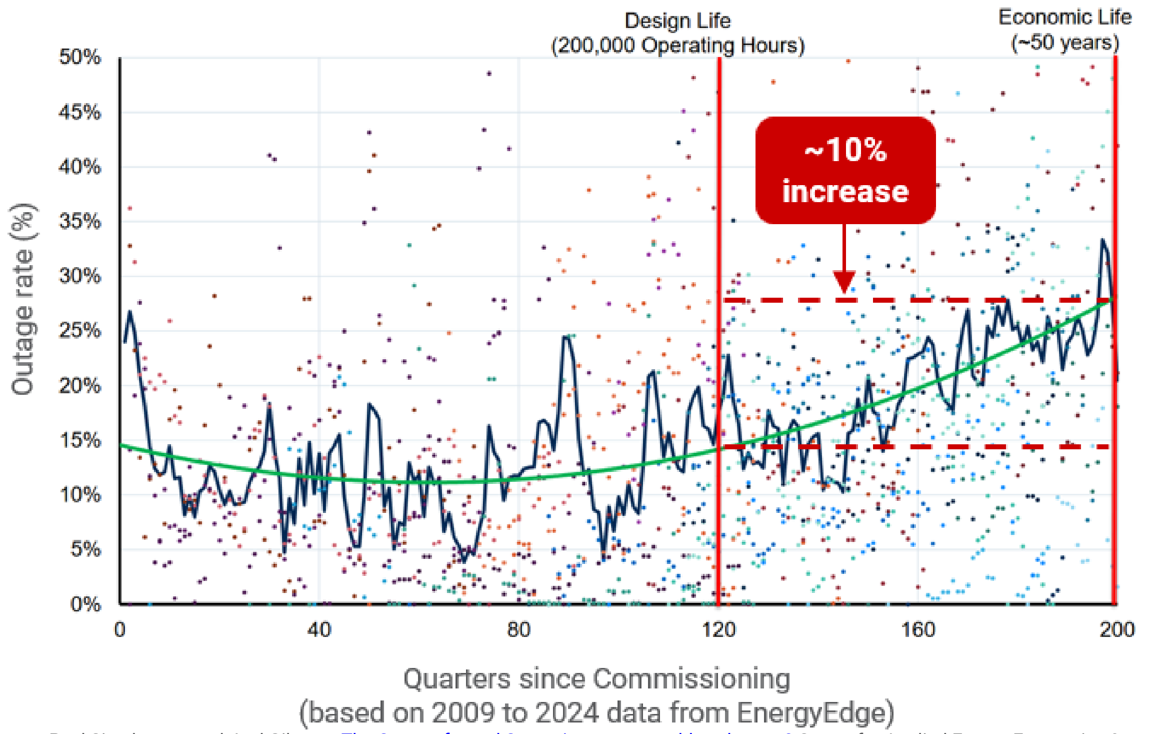
53 25-70 hour outage, occurring 15-30% of the time.

54 90-240 hour outage, occurring 5-10% of the time.

55 6000 hour outage, occurring less than 1% of the time (note that these very long duration outages don't appear in our model as the horizon is not long enough).

- We modelled this scenario by running 100 stochastic outage samples in our base case and the decreased coal reliability case, then compared the median price outcomes.

Figure 9.1: NEM coal plant outage rates (%)



Source: Paul Simshauser and Joel Gilmore, [The Counterfactual Scenario: are renewables cheaper?](#) Centre for Applied Energy Economics & Policy Research: Working Paper Series 2025-07

Faster home battery uptake

- The Federal government's Cheaper Home Batteries Program has led to a rapid increase in solar battery system installations in the NEM. We expect this to lead to lower peak demand, and therefore lower wholesale prices.
- To capture this dynamic, we modelled a scenario with 20% faster uptake of household batteries than projected in the 2025 IASR, done through an increase in regional distributed storage capacity. This corresponds to a ~1.2 GW/year increase in home battery capacity in the near term, which is fairly conservative relative to recent installations data.

Modelling the impact of demand-side scenarios on network costs

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.

List of abbreviations

ACCC	Australian Competition & Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered Price Cap
APP	Annual Pricing Proposal
ARR	Annual Revenue Requirements
ASX	Australian Securities Exchange
CPT	Cumulative Price Threshold
CAPEX	Capital Expenditure
CER	Consumer Energy Resources
COP	Coefficient of Performance
DMO	Default Market Offer
DNSP	Distribution Network Service Provider
DPPC	Designated Pricing Proposal Charges
EEIS	Energy Efficiency Improvement Scheme
ENOR	Electricity Networks Options Report
ESC	Energy Savings Contribution
ESOO	Electricity Statement of Opportunities
ESS	Energy savings scheme
EV	Electric vehicle
FERM	Firm Energy Reliability Mechanism
FET	Firm Energy Target
FCAS	Frequency Control Ancillary Services
FiT	Feed-in tariff
GSOO	Gas Statement of Opportunities
IASR	Inputs, Assumptions and Scenarios Report
ICE	Internal combustion engine
IRSR	Interregional settlement residues
ISP	Integrated System Plan
LGC	Large-scale generation certificates
LRET	Large-scale Renewable Energy Target
LT	Long Term
LTESA	Long-Term Energy Service Agreements
MFP	Market Floor Price
MLEC	Modified load export charges
MMS	Market Monitoring System
MPC	Market price cap
MW	Megawatts

MT	Medium Term
NEM	National Electricity Market
NER	National Electricity Rules
NSCAS	Network support and control ancillary services
NSLP	Net System Load Profile
NSW	New South Wales
ODP	Optimal Development Path
OPEX	Operating expenditure
OTC	Over the counter
PASA	Projected Assessment of System Adequacy
PoE	Probability of exceedance
PDRS	Peak demand reduction scheme
PRC	Peak Reduction Certificates
PTRM	Post-tax revenue model
PV	Photovoltaic
QLD	Queensland
RAB	Regulatory asset base
RCAC	Reverse Cycle Air-Conditioner
REGO	Renewable Energy Guarantee of Origin
REPS	Retailer Energy Productivity Scheme
RET	Renewable Energy Target
RIN	Regulatory information notice
RIT-T	Regulatory Information Test for Transmission
SA	South Australia
SAPN	SA Power Networks
SCS	Standard control services
SFV	Scheme Financial Vehicle
SIPS	System Integrity Protection Scheme
SRES	Small-scale Renewable Energy Scheme
SRMC	Short Run Marginal Cost
ST	Short Term
STC	Small-scale technology certificate
TAPR	Transmission Annual Planning Report
TAS	Tasmania
TNSP	Transmission network service provider
VAPR	Victorian Annual Planning Reports
VEU	Victorian energy upgrades
VEEC	Victorian energy efficiency certificates
VIC	Victoria
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital