Residential Electricity Price Trends - Wholesale Market Costs Modelling 2018

Australian Energy Market Commission

18 December 2018

Building a better working world

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1. Executive summary

The Australian Energy Market Commission (AEMC) has commissioned EY to provide advice and modelling to inform the AEMC's 2018 residential electricity price trends report. This report provides the outcomes and describes the input assumptions (including sources) and the methodology undertaken by EY to model and estimate the wholesale electricity costs in the National Electricity Market (NEM) and the Western Australia Wholesale Electricity Market (WEM). The modelling and analysis provides an estimate of the following elements of the residential electricity cost stack:

- Wholesale electricity costs (including the costs of market operator fees, network losses and ancillary services charges)
- Environmental costs associated with the RET – including LRET and SRES

These wholesale and environmental costs form part of the electricity cost stack that is included in the AEMC's *2018 Residential Electricity Price Trends* report. A summary of the methodology, drivers and trends in the wholesale electricity costs, LRET and SRES is outlined below.

1.1 Methodology

"Market modelling" in this Report refers to the process of forecasting the expected generation mix and wholesale prices in the electricity market, as an outcome of selected input assumptions. The market modelling procedure employed by EY involves running many market simulations with the 2-4-C® model to arrive at a final set of outcomes. The process involves determining a set of input assumptions, creating an initial market simulation and iterative modelling to achieve a final simulation.

For this work the most recent historical year has been modelled, or back-cast, in order to calibrate the forecast model with the most recent historical data including demand, generator dispatch and outage rates. For the WEM, as availability data is made public, outages of WA thermal generators are aligned with the time in the year they occurred. EY's approach to back-casting is the process of iteratively comparing simulated outcomes from a model with observed outcomes from actual data to test the accuracy.

The most recent publicly available data is used for key input assumptions including; electricity consumption and peak demand, customer load profiles, rooftop PV and domestic storage, electric vehicles, thermal capacity developments, new renewable capacity developments and fuel costs. These assumptions form an initial market simulation. For this Report, each future year is modelled with 50 individual iterations that make up one simulation. Results are then extracted from the model and the trends are analysed and presented below.

The method of estimating wholesale costs, involves:

- Market modelling of wholesale electricity spot prices to determine the risk for a retailer associated with uncertain wholesale costs, so that decisions around hedging can be made to manage this risk
- Determining contract strike prices using observed ASX futures contract prices (where available) and modelled wholesale contract strike prices
- Applying an exponential book build hedging strategy to reflect the way retailers progressively build up their hedge book over time
- Determining wholesale electricity purchase costs by jurisdiction for each year from 2017-18 to 2020-21

1.2 Trends and drivers of wholesale electricity spot prices

This section outlines the trends and drivers of modelled wholesale electricity spot prices from 2017-18 to 2020-21. Wholesale electricity spot prices are estimated for the purpose of determining the risk for a retailer associated with uncertain wholesale costs so that hedging decisions can be made to manage this risk. The estimated wholesale spot prices in this report are:

- not the wholesale cost that are included in the AEMC's *2018 Residential Electricity Price Trends* report
- an input into subsequent hedge modelling and the derivation of wholesale electricity purchase costs, which are the wholesale costs that are included in the AEMC's *2018 Residential Electricity Price Trends* report.

Wholesale electricity spot market prices constitute the largest component of wholesale electricity costs. Many factors influence the evolution of wholesale electricity spot market prices in the various jurisdictions of the NEM and WEM:

- In both the NEM and the WEM, significant development of new wind and solar PV generation is expected to put downward pressure on wholesale electricity prices. A summary of the key drivers of wholesale electricity prices in each region for the forecast years is outlined in the table below.
- In the NEM, based on the analysis performed, the most significant influences observed are the potential for increased or decreased energy consumption from the main grid and the entry of new generation and large-scale storage capacity. Gas and fuel cost do not significantly affect the wholesale market price over the range tested.
- In the WEM, based on the analysis performed, the most significant influence observed is variation in gas fuel price for power generation. The market design in the WEM requires generators to bid at or below short-run marginal cost (SRMC). As gas generation is frequently the marginal price setting technology in the WEM the pass-through of gas price variation is in the wholesale balancing market is strong. In the WEM the potential for change in energy consumption is somewhat moderated by change in the reserve capacity market price, minimising the relative impact on total wholesale costs.

  A summary of the key drivers of estimated wholesale electricity spot market prices for each jurisdiction is presented in the following table. The wholesale electricity cost component of a retailer is a function of wholesale electricity market prices and risk management hedge contracts. As such, the projection of the underlying wholesale electricity spot price will be moderated by the prevailing hedge contract market as discussed further in the analysis below.

Jurisdiction	Drivers of trend in wholesale electricity spot market prices
	2017-18 to 2020-21 forecast
QLD	Decreasing wholesale spot market prices from 2017-18 to 2019-20, remaining flat in 2020-21 ► Flat demand forecast over the forecast period ► New renewable generation capacity entering (including Queensland Solar 150)
NSW	Decreasing wholesale spot market prices from 2017-18 to 2019-20, remaining flat in 2020-21 ► Generally decreasing demand forecast from 2017-18 to 2019-20 ► New renewable generation capacity entering ► Increase in forecast energy consumption in 2020-21 without substantial new capacity
ACT	ACT is effectively experiencing the same trends as the NSW region
VIC	Decreasing wholesale spot market prices across forecast period ► Flat demand forecast ► New renewable generation capacity results in downward pressure on wholesale electricity market prices ► 928MW VRET plant commissioned by 2021
SA	Decreasing wholesale spot market prices across forecast period ► Decreasing demand forecast (although peak demand increases in 2018-19) ► New renewable generation capacity continues to place downward pressure on wholesale electricity market prices

Jurisdiction	Drivers of trend in wholesale electricity spot market prices 2017-18 to 2020-21 forecast
TAS	Decreasing wholesale spot prices across forecast period ► Decreasing demand forecast ► Tasmania wholesale electricity market price tends to follow Victoria and is also driven by expected new entrant wind generation in the region
WA	In the WA jurisdiction the residential electricity price is informed by a long-run marginal cost (LRMC) modelling approach. Applying an LRMC approach results in an increasing wholesale price across forecast period ► Decreasing customer energy consumption due to uptake of rooftop solar PV results in capital and fixed costs being spread over a declining energy base ► Strongly linked to gas price for power generation which is moderately increasing

- The balance of electricity market costs are projected to increase over time, however remain a relatively small proportion of wholesale costs. Ancillary services wholesale costs are projected to remain a small proportion of wholesale costs in the NEM. Ancillary services costs in the WEM are projected to increase towards around 3% of wholesale costs over the forecast period.

1.3 Summary of hedge contracting outcomes and resulting wholesale electricity cost

Large and small electricity retailers may experience different levels of exposure to customer demand usage patterns and the prevailing wholesale electricity price. These exposures may be managed through various hedging strategies. We have tested three alternative hedging strategies:

- Fully exposed to the wholesale market resulting in an average dispatch weighted price (DWP) exposure. This is likely to be a high risk position for retailers in the NEM and WEM, however it is provided as a baseline to assess alternative levels of hedge contracting. This pricing outcome also serves as a proxy for relatively short term continuous hedging which may be described as a mark-to-market (M2M) hedging approach
- Future hedge contracts in combinations of base swap, peak swap and $300/MWh caps which have been procured over a 24 month period prior to the year of market exposure
- Future hedge contracts in combinations of base swap, peak swap and $300/MWh caps which have been procured over a 12 month period prior to the year of market exposure

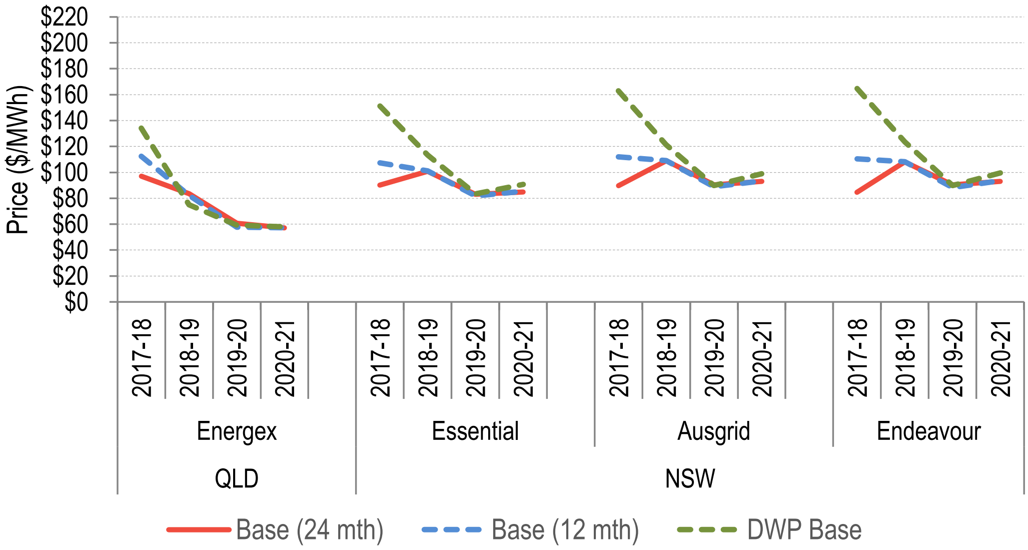
The wholesale costs presented in the AEMC's report are based on a weighted average of 12 month and 24 month hedge contract procurement, weighted by the market share of small and large retailers in each jurisdiction.

The following series of charts shows the projected wholesale electricity cost component for representative residential customer demand profiles[1] across various jurisdictional areas in the NEM and WEM for the base case scenario. The three series represent the wholesale electricity cost component under the average DWP, 24 month and 12 month hedge contract procurement strategies described above. All monetary values presented in this report are in real dollars referenced to 1 July 2018, unless otherwise specified:

- Queensland is projected to have the lowest wholesale electricity cost on average and generally declining over time as a result of expected downward pressure on wholesale prices due to significant development in solar and wind generation in the region.
- Wholesale electricity costs in NSW are more variably influenced by the nature of hedge contract strike prices and volumes. The DWP exposure is projected to decline year on year through to 2019-20. Between 2019-20 and 2020-21 grid energy consumption is projected to

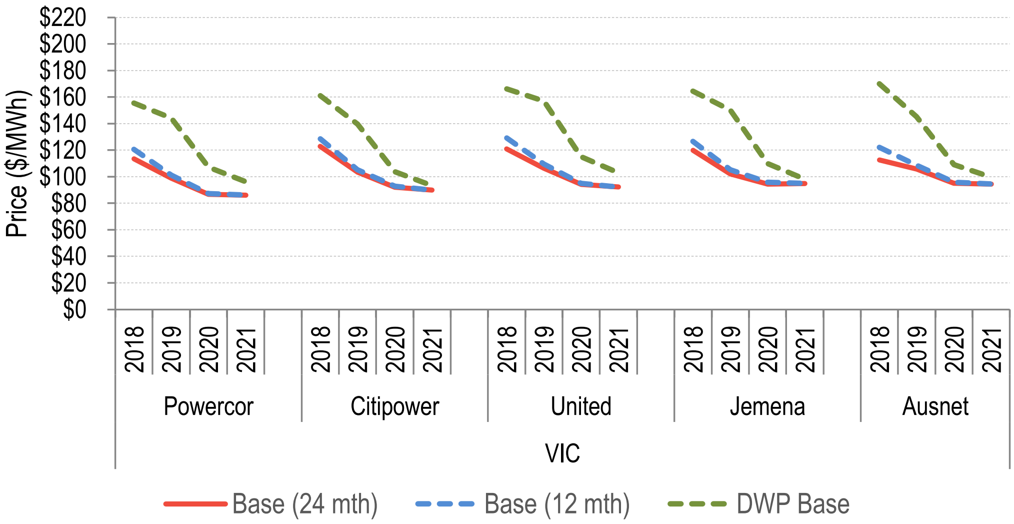
[1] Representative customer demand profiles are informed by net system load profile (NSLP) data published by AEMO

increase, resulting in a small increase in DWP. The cost of hedge contracts to minimise risk and volatility in wholesale electricity cost settlements influences the modelling calculations.



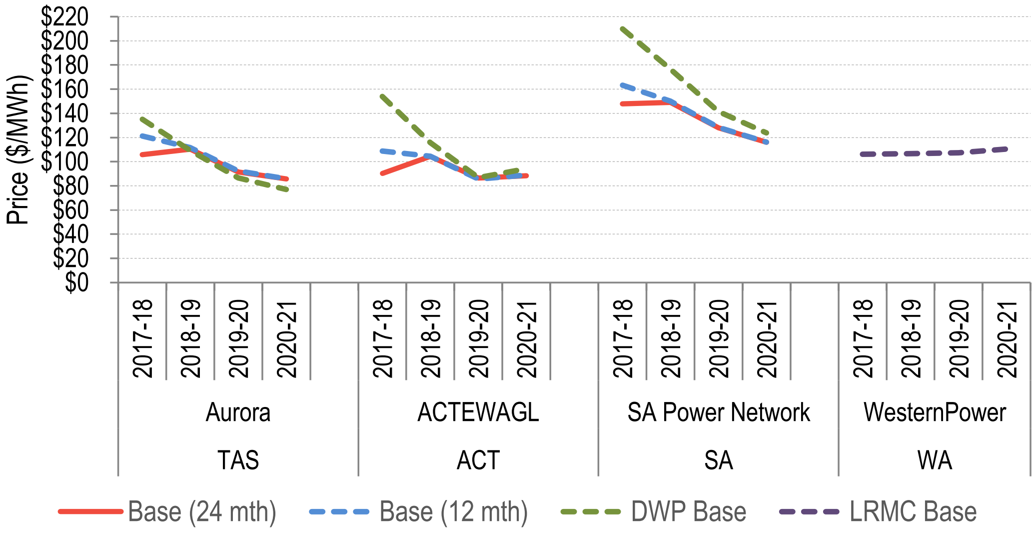
The following chart illustrates the projections for the various jurisdictions in the Victoria region of the NEM.

- In Victoria the trend in the observed DWP is likely to be a strong decline over the forecast period through to 2020-21 as a result of significant committed development of wind and solar generation. The application of hedge contracting tends to moderate the decline in wholesale costs in the Victorian jurisdictions, however the overall trend is for the wholesale cost of electricity to decline year on year for the three year forecast period.



- The outlook for wholesale cost in Tasmania is similar to Victoria, which is in line with pricing principles in the state of Tasmania. The ACT shows a similar trend to the NSW jurisdictions with the price flattening out in 2020-21 which is expected given the ACT is exposed to the NSW wholesale electricity price.
- In South Australia different hedging strategies see wholesale costs potentially lower than a DWP outlook. In all cases wholesale costs are projected to be lower by 2020-21 relative to the 2018-19 year.

- For the WEM in Western Australia, wholesale costs have been estimated using a market modelling approach and Long-Run Marginal Cost (LRMC) approach. The market modelling results were developed as an alternative comparison and are discussed later in this report. The LRMC modelling approach results in the wholesale cost forecast being in the range $105-110/MWh as shown in section 5.5 of the main report. The LRMC results are used as the estimate of wholesale costs in the AEMC's *2018 Residential Electricity Price Trends* report.



*Note that the Western Australia wholesale cost estimate is based on an LRMC modelling approach

1.4 Trends and drivers of LRET and SRES costs

For the LRET component:

- The cost component associated with the LRET is increasing over the forecast period for large retailers who have procured LGCs over a long period of time. However, there is an opportunity for small or newer retailers to procure LGCs for reducing cost over the coming years and as such the cost exposure to LRET for new retailers is expected to decline. The cost is increasing for large retailers as the LRET increases towards 33,000 GWh of new renewable annual generation by the 2020 compliance year.

For the SRES component:

- The cost exposure of the SRES policy is increasing over the forecast period. The SRES cost is approaching and may potentially surpass that of the LRET policy over the forecast period. The number of Small-scale Technology Certificates (STCs) created under the SRES continues to increase year on year, despite reductions in feed-in-tariff prices and the declining period of deeming STC accreditation through to the conclusion of the Policy at end of the year 2030.

EY also advises that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. The modelled scenarios represent several possible futures for the development and operation of the NEM and WEM, and it must be acknowledged that many alternative futures exist. We encourage the reader to ensure that they develop a thorough understanding of the sensitivity of the outcomes to key assumptions and consider these assumptions with due care before acting on the outcomes presented in this report.

2. Introduction

EY has been engaged by AEMC to provide advice and to conduct modelling to inform their 2018 Residential electricity price trends report. This Report provides the results and describes the methodology undertaken by EY to model wholesale electricity costs in the National Electricity Market (NEM) and the Wholesale Electricity Market (WEM) including input assumptions and sources.

This report is structured as follows:

- Section 3 presents a detailed methodology for the market modelling, including; an iterative approach to forecasting the NEM and WEM, market simulations and modelling limitations
- Section 4 details the data sources and policy settings used
- Section 5 presents the modelling outcomes, including; wholesale electricity market prices, retailer hedge contracting strategies and outcomes, LRMC results for the WEM, interconnector flows, ancillary services costs, market fees, LRET and SRES costs
- Appendix A and Appendix B detailing modelling assumptions for the NEM and WEM respectively

3. Detailed methodology for the market modelling

This section describes the detailed methodology applied in this assessment for modelling and forecasting the NEM and WEM. Section 3.1 describes the evolution of how the NEM and WEM are forecast using several iterations of market simulations, while Section 3.2 describes the methodology employed for each market simulation. The descriptions include the reasoning behind the approach taken for each part.

3.1 Forecasting the NEM and WEM electricity markets – an iterative approach

The term "market modelling" in this Report refers to the process of forecasting the expected generation mix and wholesale prices in the electricity market, as an outcome of selected input assumptions. The market modelling procedure employed by EY involves running many market simulations with the 2-4-C® model to arrive at a final set of outcomes. The process involves the following steps:

1. **Determine a set of input assumptions.** These assumptions include policy drivers such as the Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES), the reliability settings and other market rules as well as an electricity demand forecast, generator costs and technical parameters and many others as described in Section 3.2.
2. **Set up an initial market simulation.** Using all the assumptions, conduct an initial time-sequential half-hourly Monte Carlo market simulation over the forecast period. Assess the annual net revenues of each generator using the method of calculating net revenue described below, and determine if any new entrants or retirements would be commercially driven based on net revenue outcomes outside a tolerance range.
3. **Iterative modelling to achieve final simulation.** Adjust the new entrants and retirements through re-simulating several times until all generators have a net revenue within a specified tolerance. EY considers that when wind and solar PV generators reach their project lifetime, the sites are likely to be upgraded to new wind and solar PV generators. As such EY does not consider retirements of wind and solar PV generators in this iterative process.

3.1.1 Calculating a generator's net revenue

All capacity developments made within the market modelling procedure are determined by assessments of the net-revenue of generators modelled within 2-4-C® and for generators in the WEM, also the interactions with the capacity market. A generator's net revenue is calculated for any particular year using equation (1) for the NEM and equation (2) for the WEM below.

$$\text{NEM Net revenue} = \text{pool revenue} + \text{LGC revenue} - \text{O\&M costs} - \text{annualised capital cost repayments} - \text{fuel costs} \tag{1}$$

$$\begin{aligned}\text{WEM Net revenue} = {} & \text{pool revenue} + \text{LGC revenue} + \text{capacity payment} - \text{O\&M costs} \\ & - \text{annualised capital cost repayments} - \text{fuel costs}\end{aligned} \tag{2}$$

where

Pool revenue is the total annual wholesale market revenue earned over each trading interval in the year. In the modelling, this is the sum-product of the modelled dispatched generation and the wholesale market price over all trading intervals, multiplied by an assumed marginal loss factor for the generator. In the case of large-scale storage, the pool revenue is the difference between the revenue earned during discharge (generation) and the cost of the electricity during charging.

LGC revenue (for applicable renewable generators only) is the expected contract price earned for each MWh of production multiplied by an assumed marginal loss factor for the generator, for the period from commissioning of the project to the conclusion of the LRET Policy on 31 December 2030.

O&M costs is the total fixed and variable operation and maintenance costs. Variable operational costs may include an emissions cost associated with an emission reduction policy.

Annualised capital cost repayments is the annualised capital cost of the generator, taking into account the assumed economic life and weighted average cost of capital (WACC) for the generator.

Fuel costs is the total cost of the fuel used in the generator's modelled production of electrical energy throughout the year. The fuel cost is always zero for wind, solar PV and large-scale storage.

Capacity payment is the total annual capacity payment earned over the year.[2] In our modelling, this is equal to the amount of capacity credits allocated to a particular facility, multiplied by the calculated reserve capacity price (RCP) for that year.

In the net revenue equation the revenue earned in all trading intervals is considered in determining the commercial viability of a generator. It does not consider other potential revenue sources (other than pool revenue and capacity credits in the WEM). Additional sources of generator revenue are listed below.

- **Ancillary services**. There are several ancillary service markets in which generators can participate and earn revenue. One of the more significant of these is the Frequency Control Ancillary Services (FCAS) market, where generators can offer services to ramp up or down generation from a set point to manage the supply-demand balance. In aggregate the revenue generators currently earn for providing ancillary services is generally small compared to revenue from electricity sales, less than 2% over the past few years. In specific circumstances, generators may earn revenue from providing network control and support ancillary services.

Assessing a generator's net revenue is conducted differently depending on whether they are existing or a new entrant:

- **Existing generators**: There is no publically available data for an existing generator's capital cost repayments and in many cases the capital cost might be already paid off. As such EY assess the year-on-year net revenue of existing generators in the modelling assuming no capital cost repayments are required, and retires them on a commercial basis if the net revenue is negative (and persists with negative revenue in subsequent years).
- **New entrant generators**: In this medium-term modelling (1-5 years ahead) all committed and many projects in a very advanced stage are assumed to be developed to completion. The new renewable generation development plan includes generators that are committed, probable or confirmed under the VRET auction to enter the wholesale market over the reporting period. The specific generation projects that are included in the modelling have been agreed in consultation with AEMC and industry stakeholders and are outlined in Table 14 in Appendix A. In addition to the projects in the new renewable development plan, the model assesses whether additional generators enter the NEM, based on modelling of commercially driven new entrant decisions. These commercial decisions are based on the net present value (NPV) of a generator's net revenue over its assumed economic lifetime. As the modelling for this engagement is relatively short, no commercially driven new entrant generation is built in the modelling.

3.2 Market simulations

The market simulations are conducted using EY's in-house market dispatch modelling software, 2-4-C®. Figure 1 shows a flow diagram depicting the input assumptions and data processing used for the market simulations in this report.

[2] A single capacity year in the WEM is defined from 1 October to 1 October of the following calendar year. EY reports revenue outcomes based on a financial year basis. For simplicity, the capacity revenue is calculated on a financial year basis assuming that the assignment of capacity credits and the calculated reserve capacity price (RCP) is equal to the values in the corresponding capacity year.

Figure 1: Data flow diagram for the market simulations

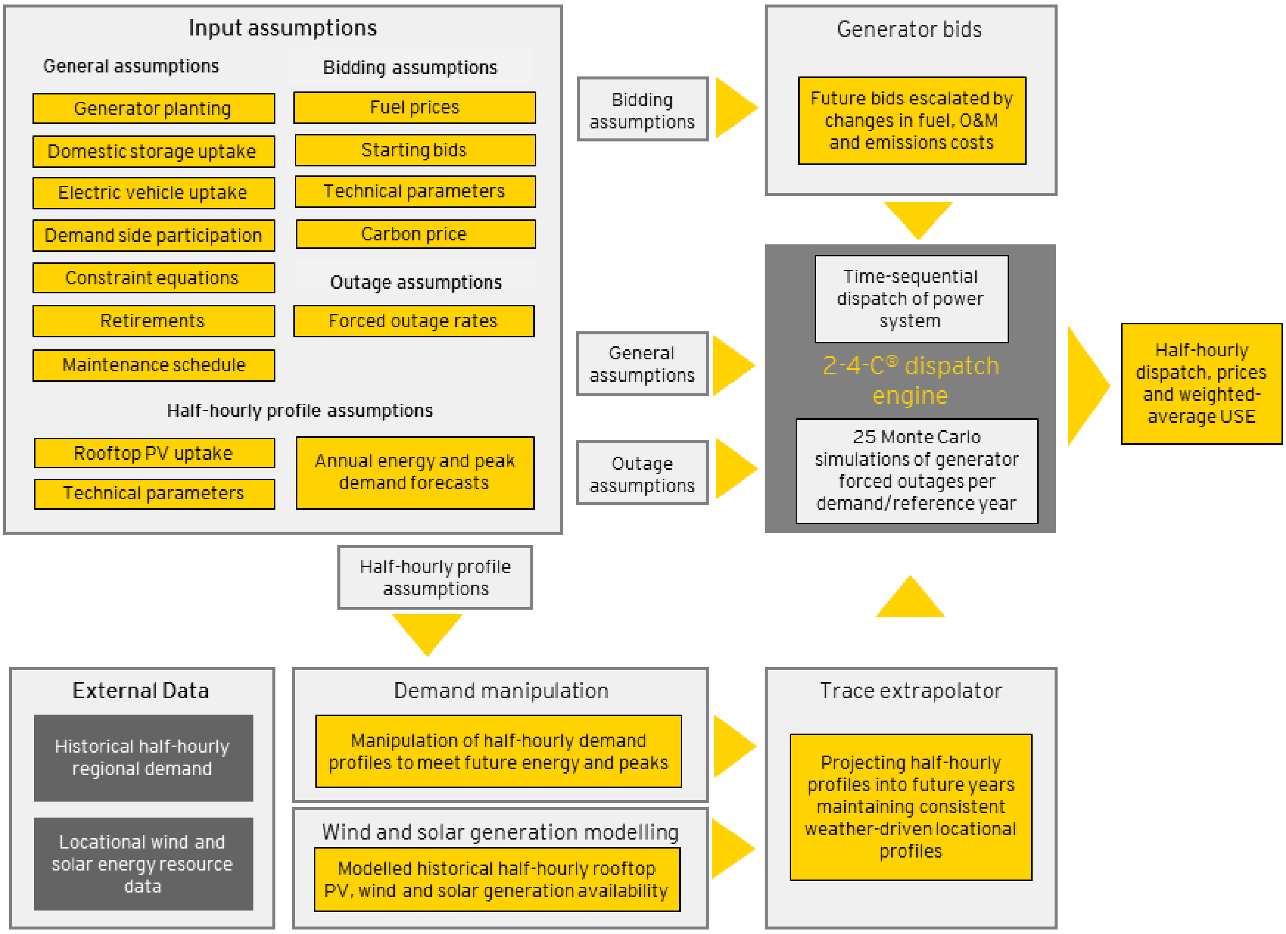


Figure 1 shows that conducting a market simulation involves establishing a large set of input assumptions. The key input assumptions and EY's methodology to modelling them in a market simulation are described in the following sections. The first of these, Section 3.2.2, describes the methodology and philosophy behind forecasting the electricity market on a half-hourly basis. Some of the input assumptions are processed in models external to the dispatch software, 2-4-C®, to determine the quantities to be used directly in the dispatch modelling. One of these determines the bids for each generator, for which the methodology is described in more detail in Section 3.2.7. An overview of 2-4-C® itself is provided in Box 2.

3.2.1 Modelling historical years

EY models historical years, or back-casts, in order to calibrate the forecast model with the most recent historical data including demand, generator dispatch and outage rates. For the WEM, as availability data is made public, the outages of WA thermal plant are aligned with the time in the year they occurred. EY's approach to back-casting is the process of iteratively comparing simulated outcomes from a model with observed outcomes from actual data to test the accuracy of the implementation of behavioural aspects such as generator trading strategies.

Since the operating conditions for most generators are confidential, EY determined suitable bidding profiles for each existing scheduled and semi-scheduled market generator in the NEM[3] using a benchmarking process. This involved simulating the half-hourly dispatch and prices for the 2017-18

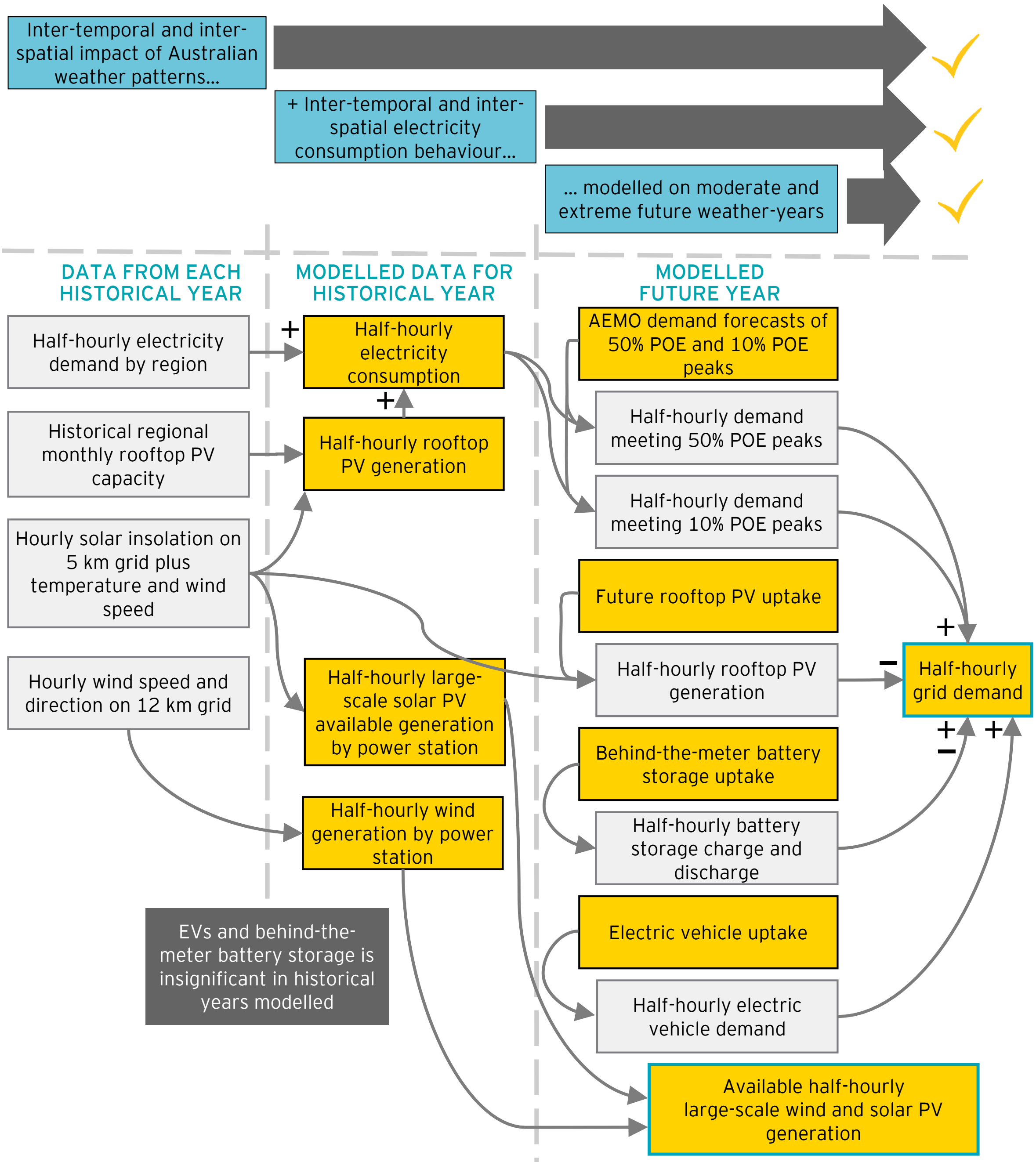
[3] In excess of 250 individual generation facilities corresponding with each dispatchable unit ID (DUID) for which bid offers are available in AEMO market data systems. Some significant non-market and non-scheduled generators are included in the modelling also, where such facilities may have an influence on network limitations and other system constraints. Of some importance to note is that this is also consistent with the basis of the applied demand and energy forecasts.

historical year with 2-4-C® and adjusting the bidding profiles for each generator with an iterative process to reproduce actual dispatch and pricing outcomes as close as practicable. The bids established through this process are applied as a baseline for all generators in the forecast period. The bidding behaviour is altered where relevant to take into account changes in direct costs, such as changes in gas and coal fuel prices in the various scenarios.

3.2.2 Forward-looking half-hourly modelling

EY's approach to forward-looking half-hourly modelling is to base all the inter-temporal and inter-spatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (reference years). Figure 2 depicts EY's methodology for modelling future half-hourly electricity demand, rooftop PV generation and large-scale wind and solar PV available generation, in terms of the data used.

Figure 2: Flow diagram showing EY's use of an historical year of electricity and atmospheric conditions data to make a half-hourly forecast



The top section of Figure 2 also highlights the approach behind what features in the historical half-hourly data are projected forward, and what features are modified to capture future conditions. These are described in more detail as follows:

- The historically observed **inter-temporal and inter-spatial impact of weather patterns** are maintained in the forecast. Historical hourly locational wind and solar resource data is used by EY to model half-hourly[4] generation from rooftop PV, large-scale solar PV[5] and wind generation. All the correlated interactions between wind and solar generation at different sites are projected forward consistently, maintaining the impact of actual Australian weather patterns. The available half-hourly large-scale wind and solar PV generation profiles are bid[6] into the market to meet grid demand in the 2-4-C® dispatch modelling. These may not be fully dispatched in case of binding network constraints or being the marginal generator and setting the price, with the volume above the marginal price being curtailed.
- **Inter-temporal and inter-spatial (regional) electricity consumption behaviour** is maintained in the forecast. Historical half-hourly grid demand is obtained from AEMO and added to EY's historical modelled rooftop PV to produce the historical electricity consumption. By projecting consumption forward instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation in changing the half-hour to half-hour shape of grid demand during each day. EY also separately models behind-the-meter storage profiles and electric vehicle charging profiles to capture their impact on the shape of grid demand.
- The historical year(s) used in the modelling consist of various types of weather, which may or may not be considered typical or average. With respect to demand, the historical electricity consumption is processed to convert it into two types of weather-years for each future year modelled. One could be considered a **moderate year**, which uses AEMO's 50% probability of exceedance (POE) peak demand forecast,[7] while the other is considered a year with more **extreme weather**, using AEMO 10% POE peak demand.[8]
- Overall, the half-hourly modelling methodology ensures that the underlying weather patterns and atmospheric conditions are projected in the forecast capturing a consistent impact on demand, wind and solar PV generation. For example, a heat wave weather pattern that occurred in the historical reference year is maintained in the forecast for each future year. The forecast is developed in the context of a moderate or extreme weather year from a demand perspective. The availability of renewable generation which is assumed to be operational within the Period is a function of the atmospheric conditions specific to each plant location and as would have been experienced across the whole NEM during the same weather event.

For this Report, each future year is modelled with 50 individual iterations that make up one simulation. The 50 iterations are comprised of:

- Two demand profiles (50% POE and 10% POE peak demand profiles)
- Five historical (reference) years of demand, wind and solar profiles
- 5 Monte Carlo simulations of different generator forced outage profiles, based on the forced outage probabilities for each generator, as estimated by AEMO

All simulated years of half-hourly results are then collated. The time-weighted wholesale market price outlook is presented as a weighted-average of 0.7 on the 50% POE iterations and 0.3 on the 10% POE iterations. The reasoning behind this weighting is discussed in Box 1. Estimating hedge contract strike prices has been completed using a simple average of all 50 Monte Carlo simulations.

[4] Hourly historical resource data is interpolated to half-hourly data

[5] The same applies to solar thermal generation

[6] EY's bidding methodology is described in Section 3.2.7

[7] The 50% POE peak demand forecast is expected to be exceeded for one half hour once in every 2 years

[8] The 10% POE peak demand forecast is expected to be exceeded for one half hour once in every 10 years

As there are an even number of 50% POE and 10% POE peak demand profile simulations, this implicitly captures a risk premium associated with potential for higher demand days.

To capture a wide range of weather patterns and their impacts on electricity demand and locational wind and solar generation EY used five reference years (as mentioned above) as the historical financial years from 2012-13 to 2016-17 for this Report. In general, the more reference years modelled, the more different types of weather patterns can be captured. However, the five years used for this Report were selected based on the following combination of reasons:

- Use of recent years captures more representative half-hour to half-hour electricity consumption behaviour for the future years modelled
- The data quality available to model wind generation prior to 2010-11 is significantly poorer than for the years selected
- The feasible limit of the amount of computational effort required in preparing the modelling informing this Report, and
- EY's recent study for AEMO's 2016 review of the Medium Term Projection of System Adequacy (MTPASA)[9] concluded a minimum of five reference years is required to adequately capture variability in renewable generation resources in Monte Carlo simulation.

Box 1: Reasoning behind weightings used to collate 50% POE and 10% POE demand outcomes

In the absence of time constraints and data availability considerations the modelling would ideally apply a very wide range of key factors such as atmospheric conditions and peak demand and simply weight each event equally. Monte Carlo iterations of unplanned outage events on generation and transmission elements are each considered to be equally likely. The sample of five reference years for atmospheric conditions and 'load shape' are also considered to be equally likely for the purpose of the modelling. Ideally we would model a large number of POE peak demand conditions however the computation time would be impractical. To manage the problem size, we limit POE peak demand samples to 10% and 50% POE scenarios. In order to establish the expected wholesale market price from these samples we assume that the probability density function of the demand POE samples are normally distributed. We then seek to find the quantum of the cumulative distribution function exceeding the 90th, 50th and 10th percentile. It is found that 30.4% of the cumulative distribution is contained above the 10th percentile, 30.4% is below the 90th percentile and 39.2% between the 10th and 90th percentile. As peak demand expectation reduces the chance of high market pricing events also reduces. We therefore make a simplifying approximation that the market price expectation is similar for all POEs below the 50% POE peak demand forecast. It then follows that we establish the expected wholesale market price from the Monte Carlo simulations as follows in equation (3).

$$\begin{aligned} Expected\ price = \ & 0.304\ \times Avg\ of\ 10\%\ POE\ USE\ (6\ Ref\ Years\ \ \times 25\ Monte\ Carlo\ simulations\ ) + 0.696 \\ & \times Avg\ of\ 50\%\ POE\ USE\ (6\ Ref\ Years\ \ \times 25\ Monte\ Carlo\ simulations) \end{aligned} \tag{3}$$

EY applies a rounded 0.3 weighting on all 10% POE outcomes and 0.7 weighting on 50% POE outcomes. While the above analysis is based on assessing expected unserved energy specifically, EY applies the weightings to all outcomes (such as generator revenues and prices) for simplicity.

The methodologies to produce the forecast half-hourly demand, wind and solar profiles for the modelling are described in more detail in the following sections.

[9] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy

3.2.3 Half-hourly locational renewable generation modelling

As described earlier, and depicted in Figure 2, EY models future half-hourly generation availability for forecast uptake of individual wind and large-scale solar PV power stations, based on historical wind and solar resource data. An overview of the methodology for wind and solar is as follows:

- **Wind**: EY's wind energy simulation tool (WEST) uses historical hourly short-term wind forecast data from the BOM on a 12 km grid across Australia to develop wind generation profiles for existing and future potential wind power stations used in the modelling. WEST manipulates the BOM wind speed data for a site and processes this through a typical wind farm power curve to target a specific available annual energy in the half-hourly profile for each power station. Existing wind farms use the historical average achieved annual energy from actual data, while all new wind farms use an assumed annual energy that varies depending on their location in the NEM.
- **Solar PV**: EY's solar energy simulation tool (SEST) uses historical hourly satellite-derived solar insolation data on a 5 km grid across Australia, obtained from the BOM, along with BOM weather station data of temperature and wind speed. The resource data from the BOM is processed using the System Advisory Model (SAM) from the National Renewable Energy Laboratory (NREL) to develop locational solar PV generation profiles. The annual energy output varies from site to site as a result of calibration to the performance of existing solar farms and the locational resource data.

3.2.4 Half-hourly demand modelling

To forecast the half-hourly demand based on a historical year, EY first constructs the historical electricity consumption profile. This is made from adding together the historical half-hourly operational demand data published by AEMO and EY's historical modelled rooftop PV generation. The historical rooftop PV is modelled with SEST using regional monthly rooftop PV capacity and annual generation published by AEMO. EY's modelled half-hourly rooftop PV generation achieves AEMO's published annual generation expectation and is based on various representative locations and installation orientations of rooftop PV systems for each NEM region.

Using AEMO's latest forecasts of annual regional electricity demand, EY's Trace Extrapolator (TEX) tool applies statistical techniques to manipulate the historical demand profile to meet future annual energy and seasonal peak demand forecasts. SEST is used to produce corresponding future rooftop PV profiles based on AEMO's forecast of rooftop PV uptake, and this is subtracted from the demand consumption to give the half-hourly operational demand for application in 2-4-C®.

Box 2: Overview of 2-4-C®

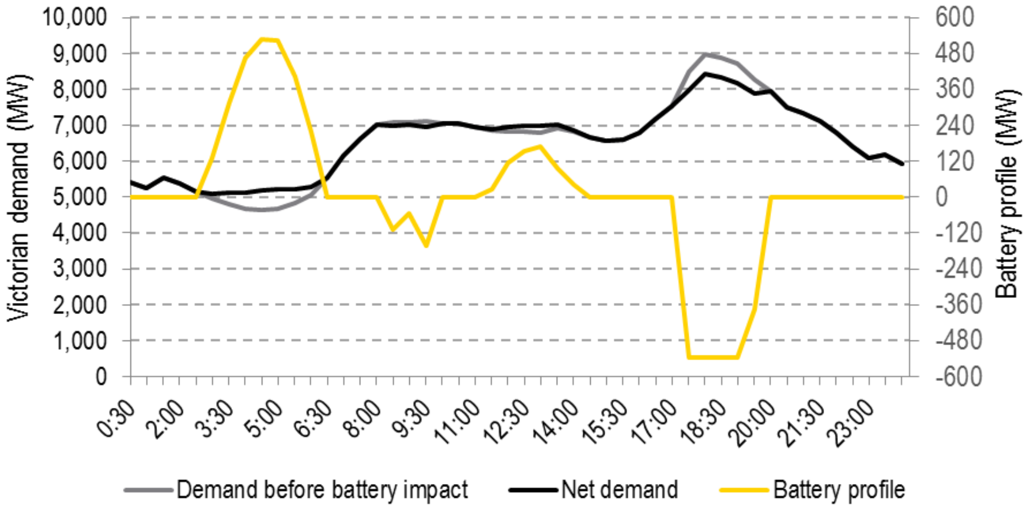
The 2-4-C® software was developed soon after the NEM inception in 1998 and is maintained entirely in-house by EY (formerly ROAM Consulting). The 2-4-C® dispatch engine is able to replicate most functions of the AEMO real-time dispatch engine (NEMDE), meaning that 2-4-C® is capable of simulating real market behaviours to the most rigorous level of detail possible in a multi-year forward-looking assessment. As with NEMDE, 2-4-C® bases dispatch decisions on the market rules, considering generator bidding patterns and availabilities to meet regional demand. The model takes into account full and partial forced outages and planned outages for each generator, half-hourly renewable energy generation availability by individual power station as well as inter- and intra-regional transmission capabilities and constraints.

3.2.5 Behind-the-meter battery storage

EY's behind-the-meter battery storage profile tool produces a seasonal time-of-day charge and discharge profile for behind-the meter battery storage for each region. The tool aims to produce an aggregate profile that responds to peak demand usage tariffs and lower priced daytime effective tariffs due to battery owners also owning rooftop PV systems. Rather than assuming a particular retail tariff structure for future battery owners, it is assumed that the tariffs will relate to the net demand profile on the distribution network – consumption minus rooftop PV generation. As a result the tool produces a fixed time-of-day discharge profile that optimally reduces the seasonal peak net demand and a charge profile that operates during the lowest periods of residual demand.

Figure 3 below illustrates an example day in winter where the battery charge and discharge cycle influences the residual demand.

Figure 3: Example day of impact of behind-the-meter battery storage in Victoria



This domestic storage profile is added/subtracted to the operational demand for 2-4-C® modelling. The amount of domestic storage modelled in each future year is provided by AEMO under different scenarios.

3.2.6 Electric vehicle demand

EY converts the annual energy expectation from electric vehicles (EVs) forecast by AEMO into half-hourly profiles to add to the grid demand used by 2-4-C®. Little is yet understood on when EVs will be charged in aggregate. EY has developed two alternative time-of-day EV demand profiles, one for weekdays and one for weekends. These profiles assume that overnight charging rolls off early in the morning, followed by an extended low period during the morning period of high electricity demand and commuting activity. Charging then increases again after people arrive at their destinations, and persists throughout the day before decreasing again in the afternoon when commuting activity commences again. Overnight charging commences significantly after the evening peak demand driven by time-of-use and peak demand tariff signals.

3.2.7 Bidding

For this project, EY has constructed central bidding profiles for each individual generator based upon recent historical data with the objective to match observed market outcomes as closely as possible. This strategy yields results that accurately model a generator's market behaviour for the majority of the time, implicitly capturing their bidding behaviour with respect to their portfolio and contracting positions. In any single trading interval, each generating unit is modelled with a bid offering their capacity at up to 10 price-quantity pairs, as in the actual market. For example, a coal unit will bid a certain proportion of its load at or near the market floor price (-$1,000/MWh) to reflect its self-commitment intention, and incremental proportions of its capacity at positive prices to reflect their running costs and higher priced bids potentially up to the market price cap to recover fixed costs and be exposed to opportunistic pricing events in the market.

Any known or assumed factors that may influence existing or new generation are taken into account in modifying these bidding profiles for the modelled future years. These may include water availability, changes in regulatory measures, fuel costs or fuel availability, carbon abatement policy or changes in total portfolio generation capacity where applicable.

Each generator and generation portfolio is assumed to retain the same general behaviour observed in the recent past. As contracting levels and prices are unknown a backcast of 2017-18, which includes bidding trend analysis of generators in that year, has been used to inform the bids for each plant in the forecast. They are broadly assumed to persist at these levels for the duration of the outlook in this study.

3.2.8 Retail portfolio optimisation

Different types or classes of retail entities have been investigated as a function of their level of vertical integration and scale of customer base. Two different types of retail entities were assessed, large and small. Based on initial modelling outcomes coupled with an analysis of published ASX futures contract values a hedge portfolio will be constructed with standard contract types including base swap, peak swap and $300/MWh cap contracts.

A large retailer is reflected by having an assumed larger and more distributed load base in terms of customer types and load profiles. Having a larger customer base is assumed to drive an ability for a larger retailer to hedge their load with a higher proportion of base swap contracts for a longer period of time of around 2-3 years. A small retailer is reflected by a smaller customer base and therefore a more uncertain load profile and demand/energy quantity to hedge. Therefore the hedging cost is likely to be more variable depending on the prevailing trend in the market due to contracts being for a shorter tenure of around 6-18 months ahead.

Anecdotally it is understood that retailers procure their desired hedge quantity over multiple smaller transactions in the lead up to the market delivery date, minimising the risk associated with short term fluctuations on the ASX futures (and over the counter) contract markets. In consultation with the AEMC, EY implemented three alternative risk management strategies to evaluate exposure to wholesale electricity cost:

1. Firstly, a dispatch-weighted price which is a proxy for a mark-to-market approach (DWP) was applied to the wholesale electricity market price forecasts for the relevant jurisdictional load.
2. An exponential 'hedge book build' procurement strategy in which futures hedge contract products are procured over a 12 month period prior to delivery. This represents the average hedging product strike prices for a relatively small retailer.
3. An exponential 'hedge book build' procurement strategy in which futures hedge contract products are procured over a 24 month period prior to delivery. This represents the average hedging product strike prices for a relatively large retailer.

Both exponential hedging procurement strategies obtained their final contracts two months before the year of the contract delivery date. For example, a hedge contract with a delivery period within the financial year 1 July 2018 to 30 June 2019 would be filled by end of April 2018. This is the case for all NEM jurisdictions except Victoria. In Victoria a calendar year period is applied and as such the hedge book build period is for the 12 or 24 months up to the end of October for each calendar year ahead. The contract strike prices were calculated by weighting the average monthly settlement prices from the ASX futures market. In future years beyond the outlook of the ASX futures market the wholesale electricity market modelling data was analysed to establish a fair value for a hedge strike price for each type of hedge contract. For base swap the fair value strike price was assessed as the simple average of all time intervals regional pool price forecast across all reference years and all 10% and 50% POE peak demand forecast cases. A peak swap was similarly assessed, but averaged over the set of periods between 7am and 10pm on working weekdays only. A cap strike price was estimated based on the observed relationship between base and peak swap hedge contracts established based on a regression of historically observed base and peak swap and cap contract strike prices from the available ASX energy futures data.

The electricity cost calculated for the different types of retailers is a combination of:

- Total contracting cost and contract for difference settlement against the forecast wholesale market price
- Settlement cost of unhedged load against the forecast wholesale market price

The objective of the retail portfolio optimisation was to determine a level of hedging that provides a consistent weekly electricity cost, based on the calculated contract strike prices, and the forecast demand, regardless of the volatility of the wholesale market price. A gradient descent algorithm was employed to optimise each portfolio.

3.2.9 Demand-side participation

Electricity consumption in the NEM has some inherent non-disclosed price response where some market-exposed consumers tend to use less power when prices are high. The impact of this is captured in AEMO's energy and peak demand forecasts modelled by EY. However, AEMO also publishes an amount of demand that is responsive to market prices, and these loads bid into the market.[10] The explicitly bidding demand side participation (DSP) data is incorporated into 2-4-C® as bidding loads as it would in the actual market. At various pricing levels, these loads are switched off in the model as would happen in the actual market.

3.2.10 Network constraints

From time to time AEMO produces an updated data set of system-normal transmission network constraint equations for use in forward-looking market modelling studies, including AEMO's own studies. EY has imported AEMO's latest available constraint equation data set into 2-4-C® for this Report.

3.3 Modelling approach for the WEM

The AEMC requested that wholesale costs in WA be considered using two separate approaches; a market modelling approach similar to the NEM and secondly by applying a long run marginal cost (LRMC) approach to calculating total wholesale market costs. The market modelling approach to forecast the wholesale balancing market price is consistent with NEM modelling approach described above, applying Monte Carlo simulation and the rules of the Wholesale Electricity Market (WEM) relating to the requirement for generators to offer energy into the market at or below short run marginal cost. In addition to the balancing market the WEM applies a reserve capacity mechanism (RCM) to incentivise sufficient investment in generation capacity and to enable generation facilities to recover fixed costs. The wholesale cost associated with the RCM is forecast by calculating the reserve capacity price and reserve capacity requirement consistent with WEM Rules. The cost associated with meeting the reserve capacity requirement for the representative retail customer is simplified for this assessment to be the total market cost for reserve capacity divided by the total forecast WEM sent-out energy consumption. This is estimate to be approximately $30/MWh over the forecast period, with the balance of wholesale market costs associated with energy purchase from the balancing market.

The remainder of this section 3.3 outlines the methodology applied for the LRMC modelling approach. EY's time sequential integrated resource plan (TSIRP) software is a least cost system wide transmission and generation optimisation model, covering the long term market development outlook. The model is specifically designed to provide the outcomes requested for the WEM and has been applied for similar engagements throughout the Australian electricity markets and other power systems. The outputs of the TSIRP model include generation capacity expansion plan, capital costs of the chosen portfolio of generation, operational costs of the chosen portfolio of generation, transmission development costs (if augmentations are part of the least cost solution), and

[10] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/Demand-side-participation

consideration of the intermittency of renewable generation technologies and energy limited nature of hydro and other storage technologies such as batteries.

EY's TSIRP model has been configured to solve for a least cost generation expansion plan to meet a sample WEM residential load shape representing A1 tariff customers. The model assumes no 'existing generation' and it must build all generation from scratch. The model commissions generation in the 2017-18 financial year. The model then augments installed capacity at the start of each financial year, if economic, to meet system demand. The modelling methodology has a hysteresis effect on the prompt-year and will only augment the installed generation base if the combined cost of new install and generation is more economic than the cost of running existing plant. TSIRP can choose to install from the following technologies:

- Combined Cycle Gas Turbines
- Open Cycle Gas Turbines
- Black Coal
- Wind (North Country location)
- Single Axis Tracking Solar
- Utility Scale Storage (batteries)

Half hourly load data has been provided by the Western Australia Public Utilities Office (PUO). In addition to meeting the representative customer load, the model has been configured to account for additional installed capacity to act as system reserves. To maintain consistency with the 2017 Residential Price Trends Report a 15% reserve margin has been applied, with open cycle gas generation the chosen technology for the reserve.

The LRMC modelling for the WEM has been applied with data described for the Base case with sensitivity to gas price resulting in Base gas price (Base), High gas price (High) and Low gas price (Low) scenarios. The modelling output is further broken down by financial year. The overall LRMC of the system is the generation production weighted LRMC of each individual technology for each financial year.

3.4 Modelling limitations

3.4.1 Long-term generator profitability assessment

New entrant generator investment decisions are typically made based on a market assessment over the economic lifetime of the generator. For this Report a full economic lifetime assessment of new entrant capacity options is out of scope in all scenarios, but also deemed unnecessary for the following reason:

- New entrant renewable projects built up to 2020 are driven by the LRET, VRET and other government policy settings (i.e. the Queensland Government's Solar 150 program) where the available additional subsidy supplements the development risk at least to the period ending the year 2030, reducing the need to determine their long-term economic viability.

In addition to the above, EY's generator profitability assessment is based on the modelled commercial signals only, and does not explicitly take into account the impact of uncertainty in investment decisions (such as due to the present uncertainty surrounding emissions reduction policies in the NEM). However, uncertainty can be captured through the choice of the weighted-average cost of capital (WACC), which is a key assumption that impacts on the annualised repayments on capital costs modelled in EY's generator profitability assessment/net revenue.

3.4.2 Contracts and portfolio impacts

Due to a lack of transparent information on factors such as:

- Retail arrangements
- Risk tolerance, and
- Financial positions, including contracts

A large number of additional assumptions would have to be made in order to implement dynamic bidding. Dynamic bidding involves making many assumptions based on little available data to allow the Nash equilibrium to find reasonable solutions for how bidding could occur in the market. The central historically-based bidding strategy established for each generator implicitly captures the current contracting and risk management strategies.[11] Therefore, in the absence of significant structural changes in the market such as ownership changes or changes in the market design it presents a reasonable reflection of expected behaviour of market participants for the majority of time.

3.4.3 Generator bidding behaviour

As detailed in Section 3.2.7 the bids for each generator have been informed by bidding trend analysis of generators in 2017-18. They are broadly assumed to remain at these levels for the duration of the forecast period. This approach does not capture the potential for changes in the bidding behaviour of profit maximising entities which may result in higher prices under certain conditions.

[11] In particular, we note that Queensland generators changed their behaviour in early 2017 compared to trading strategies in the 2016 period. The recent bidding strategies employed by Queensland generators have been captured.

4. Data sources and policy settings

4.1 Scenarios considered in the modelling

The AEMC requested EY model five scenarios, to reflect the impact of different demand and fuel cost assumptions on wholesale electricity cost outcomes in the NEM and WEM.

Table 1 describes the agreed scenarios modelled by EY for this work.

Table 1: Modelled scenarios

Scenario	RET	Demand	Fuel prices
1 Base case	Current LRET of 33,000 GWh by 2020. SRES policy unchanged	AEMO 2018 Electricity Statement of Opportunities (ESOO) – Medium forecast	Mid-range forecast
1a Base case + low fuel price			Low price forecast
1b Base Case + high fuel price			High price forecast
2 Low demand		AEMO 2018 ESOO – **Low** forecast	Mid-range forecast
3 High demand		AEMO 2018 ESOO – **High** forecast	Mid-range forecast

4.2 Key assumptions

Assumptions and key data sources are discussed in Table 2 below. All monetary values presented in this report are in real dollars referenced to 1 July 2018, unless otherwise specified.

Table 2: Overview of key assumptions

Key driver	Description	Source/Rationale
Assumptions affecting demand/energy consumption		
Load - energy and peak demand	We use the latest available AEMO forecast: ► For the NEM this is currently the 2018 Electricity Statement of Opportunities (ESOO) ► For the WEM, this is the 2018 Electricity Statement of Opportunities (ESOO), released for the WEM in June 2018	► AEMO, 2018 Electricity Statement of Opportunities (NEM/WEM)
Rooftop PV	Rooftop PV has proliferated in recent years driven by government policies. AEMO expects significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs.	► AEMO, 2018 ESOO
Demand-side participation	DSP can play a role in protecting large and responsive customers from very high market prices.	► AEMO, 2018 ESOO
Assumptions regarding market policies		
Large-scale renewable energy target (LRET)	The new legislated targets require 33,000 GWh per annum of eligible renewable energy from 2020 to 2030.	► Present legislated target
Carbon price	The introduction of a carbon price could be a potential policy setting to drive decarbonisation of the electricity sector to contribute to Australia's emissions abatement targets.	► No explicit carbon price
5 minute settlements	The new electricity rule on 5 minute settlement is to commence 1 July 2021 in the NEM, which is outside the reporting period from 2017/18 to 2020/21. In Victoria, the modelling of wholesale prices was completed for the calendar years from 2018 to 2021 and assumed that 30 minute settlement would remain in place for the entire reporting period.	► 30 minute settlements to apply, AEMC

Table 2: Overview of key assumptions		
Key driver	Description	Source/Rationale
Assumptions affecting market supply		
Thermal generation developments	The introduction and retirement of thermal capacity play a significant role in the demand and supply balance in the NEM.	► These capacity developments are based on public announcements that are committed or probable, such as the state Government funded large-scale battery storage developments. ► AEMO 2018 Generation Information on generator entry and exit (i.e. mothballing and return to service).
Fuel prices	The price for natural gas and coal is a key influence on market prices, influencing the bidding strategies of thermal generators.	► AEMO, 2018 ISP
Constraint equations	AEMO publishes a data set of constraint equations from time to time.	► AEMO, 2016 constraints workbook
Technology capital costs	The latest industry-led extensive review of capital costs for a broad range of generation technologies.	► AEMO, 2016 NTNDP
Technology parameters	The assumed technical parameters of existing and new entrants has a material influence on the annualise cost of new entrant generation.	► AEMO, 2016 NTNDP
WACC	The WACC is used to evaluate the annualised repayments of capital costs for each generator. It could be a different number depending on the technology. In this modelling, 7.5% real pre-tax is applied for all technologies.	► 2015, IPART Review of Regulated Retail prices

5. Modelling outcomes

This section presents projected wholesale electricity market prices for the NEM and WEM, demand weighted electricity prices by customer jurisdiction and retailer hedge contracting strategies and outcomes. Other outcomes of the modelling such as the generation capacity expansion and energy production, interconnector flows and market fees are presented in this section.

The method of estimating wholesale costs, involves:

- Market modelling of wholesale electricity spot prices to determine the risk for a retailer associated with uncertain wholesale costs, so that decisions around hedging can be made to manage this risk
- Determining contract strike prices using observed ASX futures contract prices (where available) and modelled wholesale contract strike prices
- Applying an exponential book build hedging strategy to reflect the way retailers progressively build up their hedge book over time
- Determining wholesale electricity purchase costs by jurisdiction for each year from 2017-18 to 2020-21.

The modelling outcomes presented in this section are structured as follows:

- Wholesale electricity spot market prices
- Demand weighted electricity price
- Retailer hedge contracting strategies and outcomes
- Generation capacity expansion and energy production
- WEM LRMC approach outcome
- Interconnector flows
- Ancillary services cost
- Market fees
- Large-scale Generation Certificate costs
- Small-scale Technology Certificate cost, and
- Application of loss factors

5.1 Wholesale electricity spot market prices

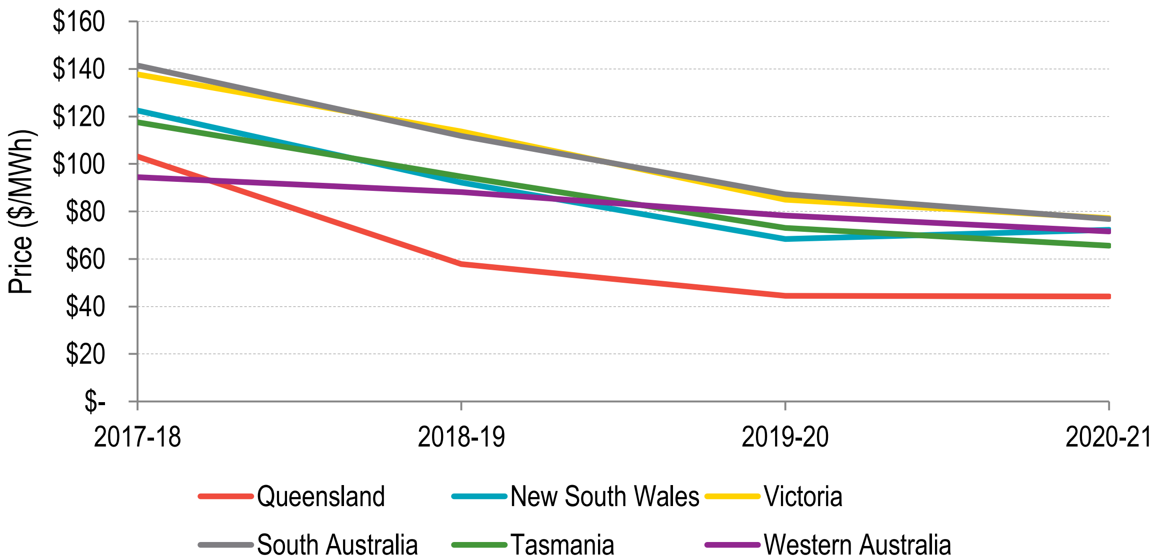
The main driver visible in the market prices in the base scenario is the relatively mild demand growth and increased renewable development driven by the LRET and VRET policy. Queensland present lower pool prices driven by changes in the bidding behaviours of larger thermal units in 2017-18 and then influenced in forecast years by the installation of new wind and solar plant in the State. A summary of the key drivers for each region can be seen in Table 3 below. Applying the key drivers and modelling assumptions for all scenarios, the modelling does not result in commercially driven new entrant generation developments in excess of the committed new entrant generation list.

A summary of the key drivers of wholesale electricity market prices for each jurisdiction is presented in the following table. The wholesale electricity cost component of a retailer is a function of wholesale electricity market prices and risk management hedge contracts. As such, the projection of the underlying wholesale electricity market price will be moderated by the prevailing hedge contract market as discussed further in the analysis below.

Table 3: Drivers of trend in wholesale electricity spot market price outcomes	
Jurisdiction	2017-18 to 2020-21 Forecast
QLD	Decreasing wholesale spot market prices from 2017-18 to 2019-20, remaining flat in 2020-21 ▶ Flat demand forecast over the forecast period ▶ New renewable generation capacity entering (including Queensland Solar 150)
NSW	Decreasing wholesale spot market prices from 2017-18 to 2019-20, remaining flat in 2020-21 ▶ Generally decreasing demand forecast from 2017-18 to 2019-20 ▶ New renewable generation capacity entering ▶ Increase in forecast energy consumption in 2020-21 without substantial new capacity
ACT	ACT is effectively experiencing the same trends as the NSW region
VIC	Decreasing wholesale spot market prices across forecast period ▶ Flat demand forecast ▶ New renewable generation capacity results in downward pressure on wholesale electricity market prices ▶ 928MW VRET plant commissioned by 2021
SA	Decreasing wholesale spot market prices across forecast period ▶ Decreasing demand forecast (although peak demand increases in 2018-19) ▶ New renewable generation capacity continues to place downward pressure on wholesale electricity market prices
TAS	Decreasing wholesale spot market prices across forecast period ▶ Decreasing demand forecast ▶ Tasmania wholesale electricity market price tends to follow Victoria and is also driven by expected new entrant wind generation in the region
WA	Decreasing wholesale spot market prices across forecast period when applying a market modelling approach ▶ Decreasing demand forecast ▶ New renewable generation capacity results in downward pressure on wholesale electricity balancing market prices

The forecast wholesale electricity spot market price outcomes for each region are shown in Figure 4 below.

Figure 4: Average wholesale electricity spot market price forecast for the base scenario



* Note that the Western Australia wholesale electricity price in Figure 4 is based on market modelling and includes the estimated cost associated with the reserve capacity mechanism in addition to wholesale balancing market price
** ACT results are based on NSW price outcome

Table 4 provides an overview of the differences between each scenario and key trends observed in the wholesale spot price results.

Table 4: High level trends in the wholesale electricity spot price, by scenario	
Scenario	Key trends in wholesale pool prices
Base case	General price trends are driven by new entrant renewables commissioned to meet the RET, leading to a reduction in pool prices over the forecast period. The price trends downward as new lower cost renewables are commissioned to satisfy the RET.
High fuel	This scenario models the same demand levels as the Base case, but implements higher fuel costs. The results in this scenario are higher than the Base case forecasts in all jurisdictions in all years of the forecast period. This is driven by the higher fuel costs faced by gas generators across the NEM and WEM and for export-exposed coal-fired generators in Queensland and New South Wales. These plant are often the price setters, hence the wholesale price tends to reflect the increase in the fuel cost. The price trends downward as new lower cost renewables are commissioned to satisfy the RET.
Low fuel	This scenario models the same demand levels as the Base case, but implements lower fuel costs. The prices in this scenario are lower than those in the Base case in all jurisdictions in all years of the forecast period reflecting the pass through of reduced input fuel costs for thermal generators. The price trends downward as new lower cost renewables are commissioned to satisfy the RET.
High demand	This scenario models AEMO's high demand forecast from the 2018 ESOO. The wholesale prices are higher than the Base case in all jurisdictions in all years. Higher demand is serviced by higher-cost generators being dispatched. These generators are at times the marginal price setting generator which causes prices to increase. The price trends downward as new lower cost renewables are commissioned to satisfy the RET before levelling out in the last year of the outlook.
Low demand	This scenario models AEMO's low demand forecast from the 2018 ESOO. The results for this scenario are lower than the Base case in all jurisdictions in all years. When demand is lower, gas is less likely to be the marginal price setting generator and therefore the prices more frequently reflect lower coal and renewable generator marginal costs. The price trends downward as new lower cost renewables are commissioned to satisfy the RET.

5.2 Demand weighted electricity price (DWP)

Price outcomes are reflective of changes in the wholesale market cost component. The following charts present the forecasting approach outcomes for 2017-18 and the future 2018-19 to 2020-21 years (2018 to 2021 calendar years in the case of Victoria). In the low demand scenario, demand is met by lower cost generators and relies less on gas generators setting the price in the NEM. Conversely in the high demand outlook the market price is more frequently set by higher priced generation resulting in an increased DWP. In the NEM the sensitivity to gas price for power generation is relatively small.

Figure 5 below shows the demand weighted electricity price outcomes for each jurisdiction in Queensland and New South Wales. DWP generally decreases across the reporting period in all jurisdictions. In the New South Wales (and ACT) jurisdictions the DWP increases in 2020-21 relative to the previous 2019-20 year where it decreases. The market price response in 2020-21 is driven by a combination of increasing energy and peak demand in the absence of new generation development in the New South Wales region. A marginally higher time weighted wholesale electricity market price is accentuated by a stronger correlation between high customer demand and high market price periods in the evening, after solar PV generation has stopped operating.

Figure 5: Customer demand weighted electricity price for QLD and NSW, all scenarios

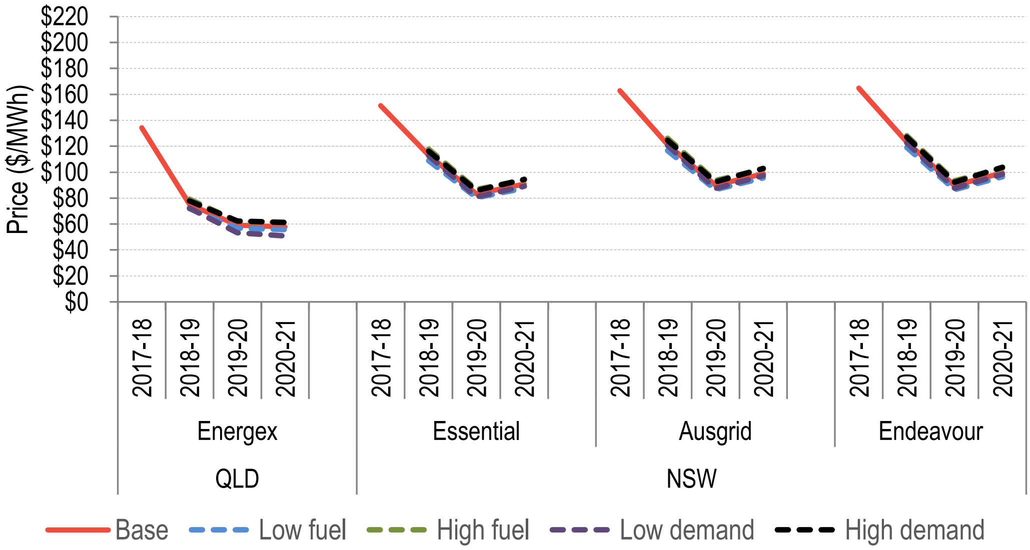


Figure 6 below shows the demand weighted electricity price outcomes for each jurisdiction in Victoria. DWP decreases across the reporting period in all Victorian jurisdictions.

Figure 6: Customer demand weighted electricity price for VIC, all scenarios

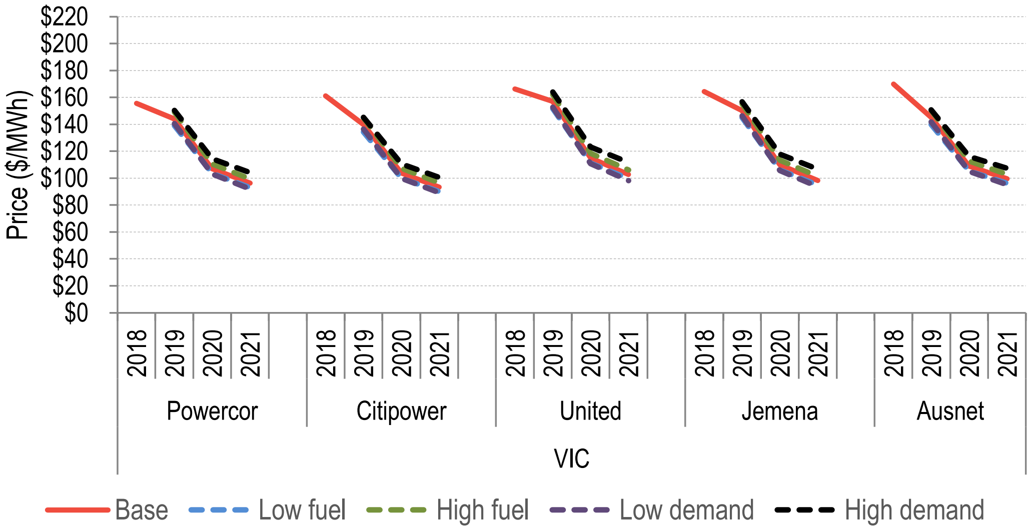
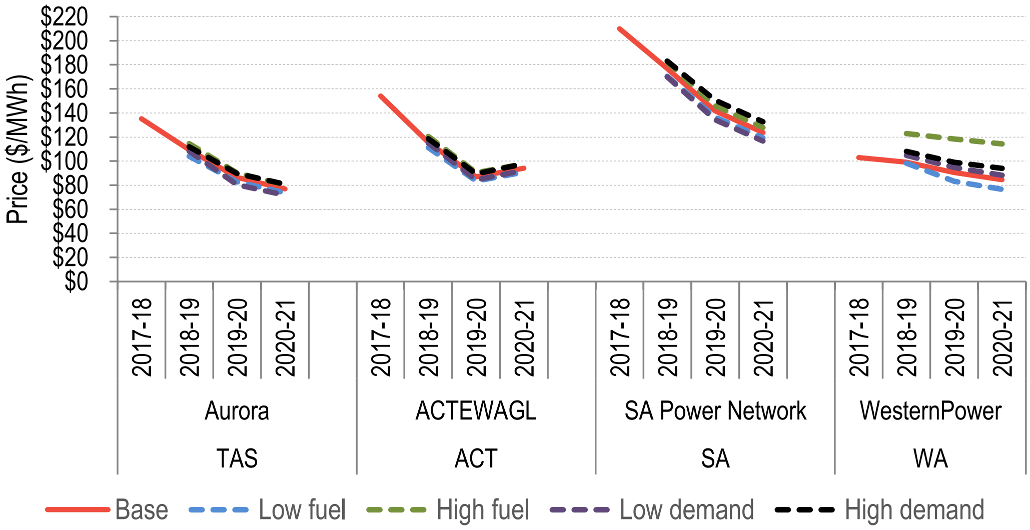


Figure 7 below shows the demand weighted price outcomes for retail jurisdictions in Tasmania, Australian Capital Territory, South Australia and Western Australia. In WA the price outcomes are influenced by the reserve capacity cost in addition to the wholesale balancing market. For example, in the low demand scenario the total wholesale cost is very similar to the base case. This is due to the reserve capacity cost being higher on a per MWh basis which counter-balances the lower balancing market price. As a result, the fuel price scenarios result in higher variation to total wholesale costs compared with the demand scenarios.

Figure 7: Customer demand weighted electricity price for TAS, ACT, SA and WA, all scenarios



*AEMC may use an alternative wholesale cost approach in Tasmania based on the Wholesale Electricity Pricing Order[12]

5.3 Retailer hedge contracting strategies and outcomes

EY's hedging approach uses the forecast half-hourly wholesale pool price outcomes and published ASX Energy futures data to develop synthetic futures prices of standard hedging instruments (baseload and peak swaps and caps). The optimal quantity of each instrument that would be necessary to provide hedge cover for each jurisdiction is estimated to determine the total hedging cost. The Aurora jurisdictional contract strike prices were based on the Victorian wholesale market price outcomes in line with Tasmanian retail price setting principles[13]. Western Power was excluded from these calculations as there is no active futures market on which to base theoretical strike prices.

As described in section 3.2.8 above two alternative hedge book build approaches have been applied being a 12 month and 24 month accumulation strategy. The general trends observed in the DWP approach are less prominent when applying hedge contracting principles and more variable across the regions and through the forecast period. When the 24 month exponential hedging procurement strategy is applied the hedge strike prices for each product are tending to increase from 2017-18 to 2018-19 in the NSW region.

The 12 month exponential hedging procurement strategy typically resulted in a higher price for the 2017-18 historical year compared with the 24 month exponential hedging procurement strategy. This higher price is a reflection of higher ASX futures in the recent year. Under the exponential hedging strategy the majority of contracts will be procured closer to the delivery period. The 12 month exponential hedging procurement strategy is more exposed to the more recent period of higher prices. For the forecast period the 12 month and 24 month hedge strategy result in similar wholesale electricity cost outcomes. In the longer term the hedged and DWP projections tend to align as the synthetic future strike price for hedge products becomes more strongly weighted by the wholesale market price forecasts.

[12] https://www.economicregulator.tas.gov.au/electricity/pricing/retail/pricing-approvals

[13] In AEMC's *2018 Residential Electricity Price Trends* report wholesale cost for Tasmania are based on the Tasmania Wholesale Electricity Price Order for 2017-18 and 2018-19 only. The growth rate from EY's modelled Tasmanian wholesale cost is applied to the 2018-19 price order costs for 2019-20 and 2020-21.

Figure 8: Retail hedge weighted electricity price for QLD and NSW, base scenario

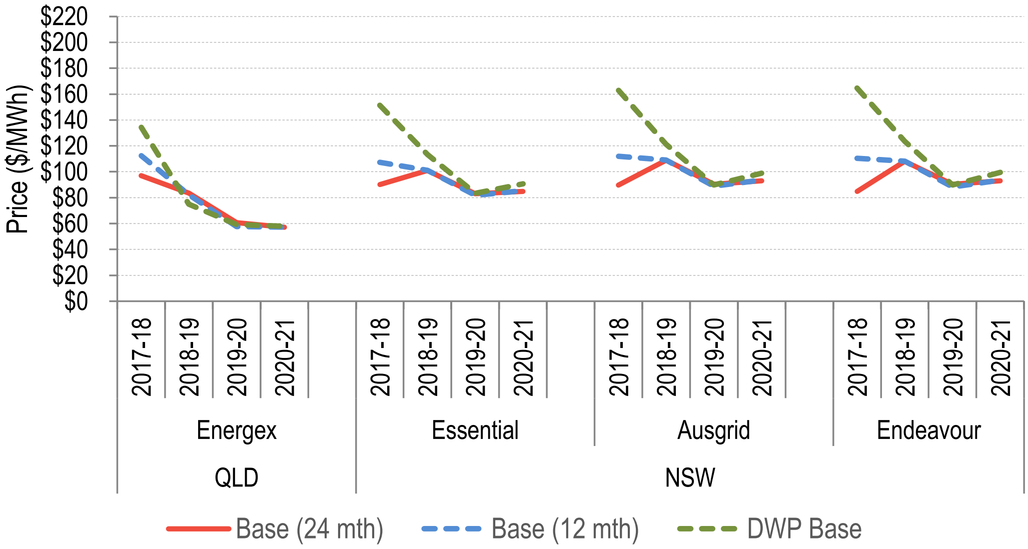


Figure 9: Retail hedge weighted electricity price for VIC, base scenario

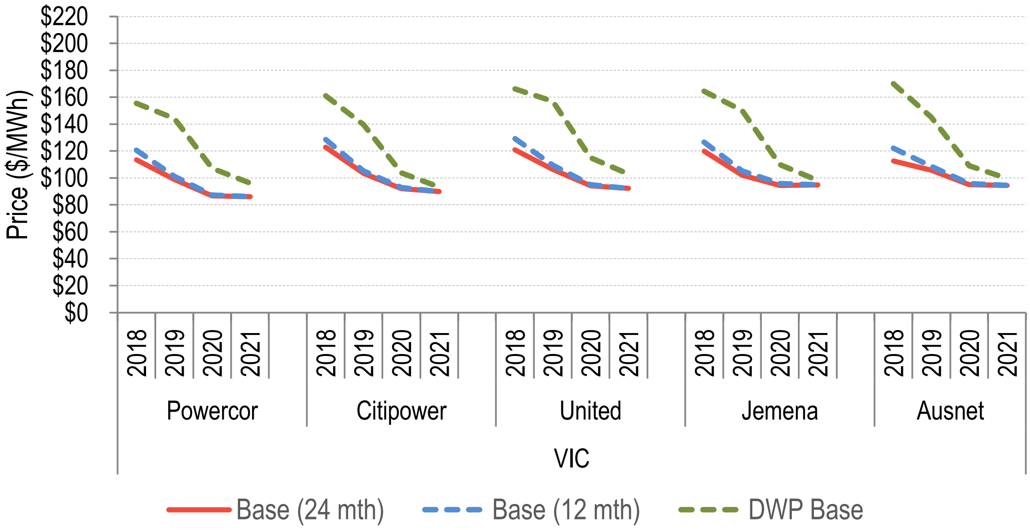
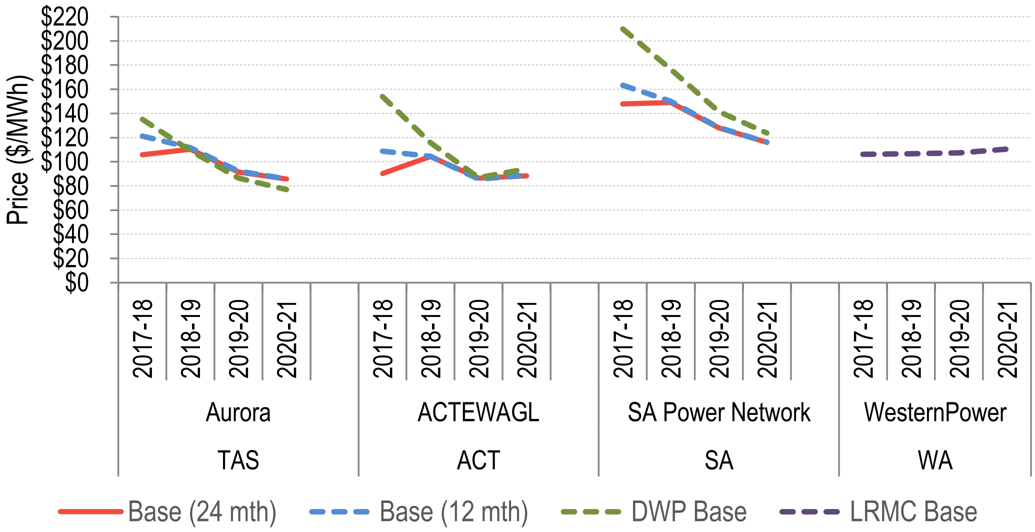


Figure 10: Retail hedge weighted electricity price for TAS, ACT, SA and WA (LRMC), base scenario



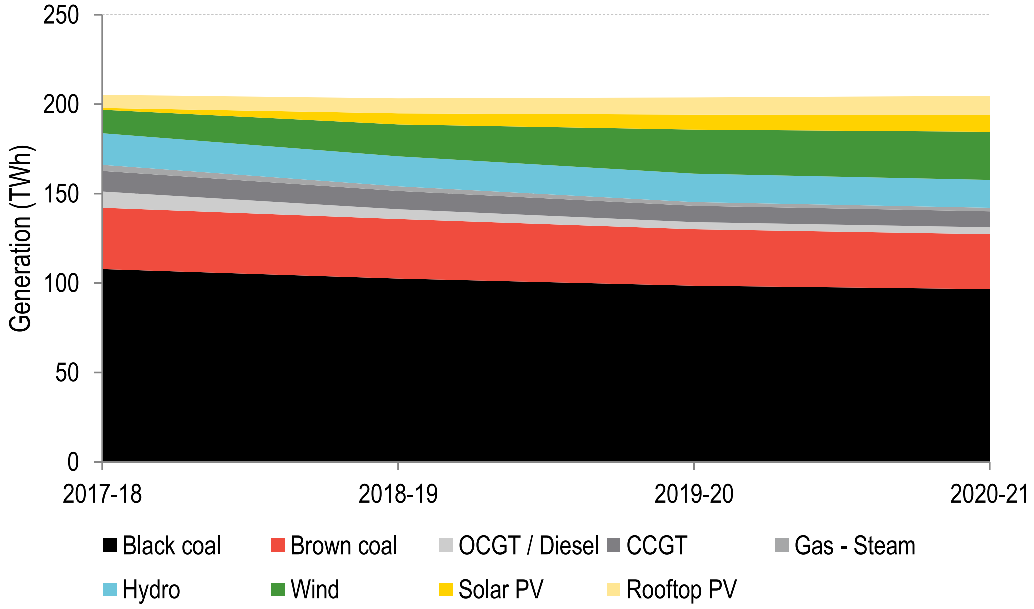
*Note that the Western Australia wholesale cost estimate is based on an LRMC modelling approach

5.4 Generation capacity expansion and energy production

The proportion of electricity generated by each technology type is again driven primarily by the RET policy. In the base scenario there is increasing generation from wind and solar due to the RET. Over the forecast period there is 9,733 MW of new capacity entering the NEM, of which 8,962 MW is renewable and 771 MW is non-renewable. The plant modelled are named in Appendix A.9 and A.10.

Figure 11 below shows the sent-out generation (TWh) by technology in the base scenario. A small reduction in generation from black and brown coal generators can be seen over the forecast period. In addition, an uptake in generation from wind and solar plant can be seen by 2020-21. Overall, the increase in total generation reflects an increase in demand across the NEM, and the change in technology reflects additional plant installed to meet the RET.

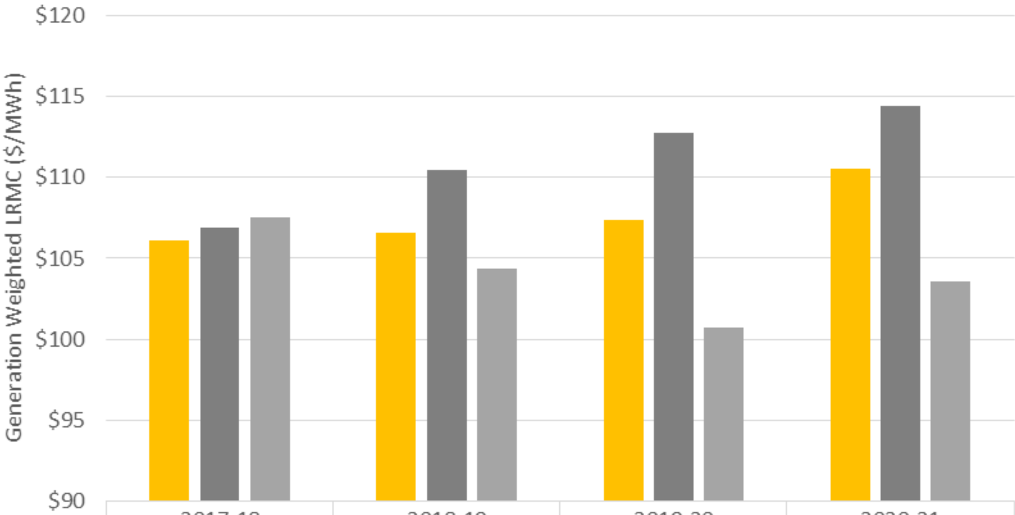
Figure 11: Generation by type in the base scenario



5.5 WEM LRMC approach outcome

Figure 12 presents the LRMC modelling outcomes for the WEM by fuel price scenario and financial year. In the base fuel price scenario, the system delivers an LRMC of $106/MWh in 2017-18, gradually rising to $110/MWh in 2020-21. The high, low and base fuel price scenarios start off in a similar position and then diverge to LRMCs above and below base prices respectively. It's important to note that the model is optimising for the lowest system cost over the entire forecast period. Whilst it can be counter-intuitive to have a higher LRMC in the 'low fuel price' scenario compared with the base case, its whole of life costs are significantly lower. Compared to the existing market where a smaller proportion of installed capacity is gas based, fuel prices in the LRMC approach have a significant impact on price outcomes. LRMC prices are quite sensitive to assumed fuel prices and this is reflected in each scenario's price curve. The base scenario has its price curve lifting slightly, the high gas price scenario has a steeper lift and the low gas price curve is falling. This generally follows the gas price forecast shown in Appendix B.12.

Figure 12: LRMC by fuel price scenario

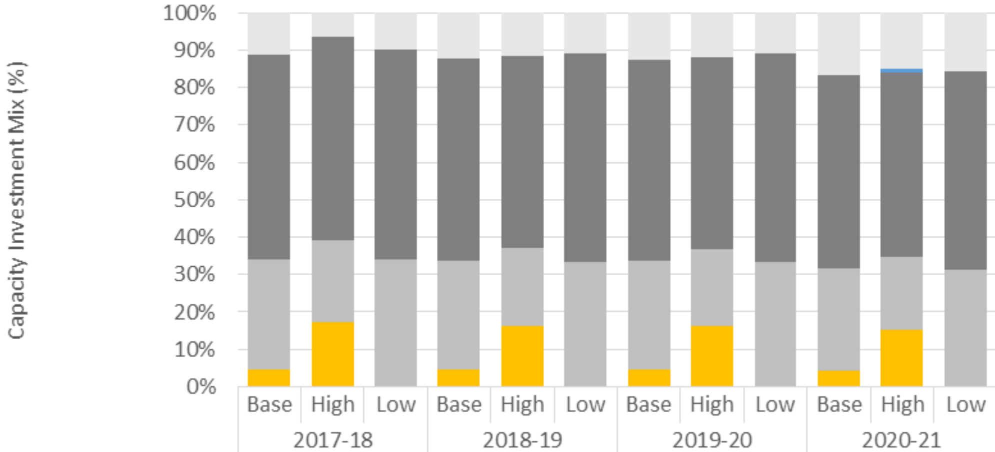


	2017-18	2018-19	2019-20	2020-21
Base	$106	$107	$107	$110
High	$107	$110	$113	$114
Low	$108	$104	$101	$104

A sensitivity analysis was also completed on the high fuel price scenario to test the effect of high coal capex on LRMC. Coal capex applied in the LRMC is from AEMO's NTNDP prices as shown in Appendix B.10. A 20% increase in coal capex prices is estimated to result in a $5 to $6/MWh uplift in LRMC across all years.

Figure 13 presents the proportion of generation technology that has been installed by the model to meet load for each fuel price scenario. The table below provides installed capacity for all scenarios and financial years for the given reference A1 customer load. The magnitude of the capacity is a function of the scale of the load data provided and is not to be considered representative of the entire WA WEM. The majority of installed capacity is in OCGT technology followed by CCGTs and Wind. Black coal generation and a small amount of utility scale battery (20 MW in 2020-21) appears in the high fuel price scenario.

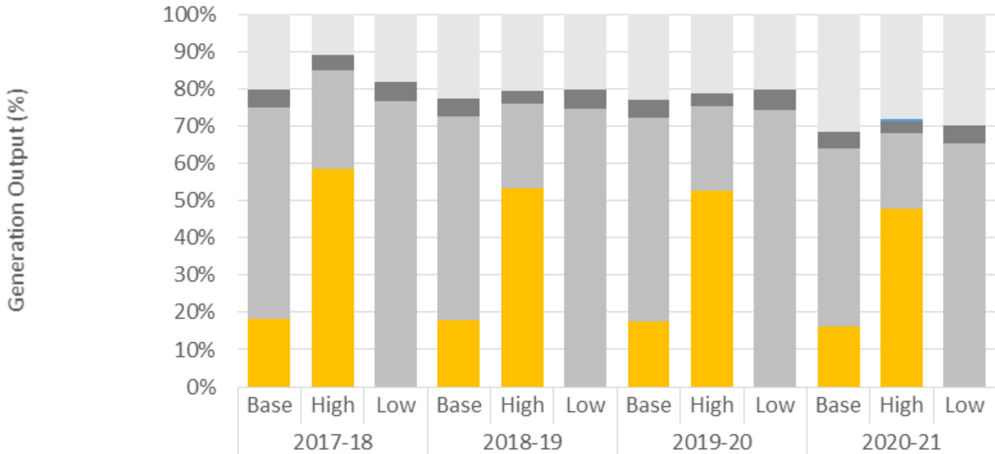
Figure 13: Installed generation in MW



	2017-18			2018-19			2019-20			2020-21		
	Base	High	Low	Base	High	Low	Base	High	Low	Base	High	Low
Wind SWIS	265	147	231	294	274	259	298	282	259	422	383	394
Utility Battery SWIS	0	0	0	0	0	0	0	0	0	0	19.54	0
OCGT SWIS	1280	1214	1313	1293	1226	1325	1293	1226	1325	1313	1246	1346
CCGT SWIS	694	493	792	694	493	792	694	493	792	694	493	792
Black Coal SWIS	108	387	0	108	387	0	108	387	0	108	387	0

Figure 14 shows the annual proportion of generation by technology along with a table of energy production. Even though OCGTs deliver the highest installed capacity, they are used sparingly due to high variable running costs, with the system maximizing energy production from high efficiency CCGTs. In the high fuel price scenario, where coal is economic, it acts as the system base load energy provider. High capacity factor wind resources consistent with northern WA allows wind to contribute a significant portion of energy production in all scenarios.

Figure 14: Generation output in GWh



	2017-18			2018-19			2019-20			2020-21		
	Base	High	Low	Base	High	Low	Base	High	Low	Base	High	Low
Wind SWIS	1009	565	884	1108	1034	979	1116	1057	973	1522	1402	1429
Utility Battery SWIS	0	0	0	0	0	0	0	0	0	0	23	0
OCGT SWIS	239	210	259	243	182	263	246	184	268	214	157	229
CCGT SWIS	2816	1346	3769	2690	1141	3628	2656	1130	3593	2316	998	3123
Black Coal SWIS	900	2988	0	879	2677	0	865	2624	0	775	2379	0

5.6 Interconnector flows

Figure 15 and Figure 16 show the average annual interconnector flows between the NEM regions for all scenarios. The trend is similar between all scenarios and the overall interconnector flow is influenced by capacity developments and demand forecasts for each region.

- Basslink shows higher levels of export to Victoria in the low demand scenario as Tasmania demand reduces.
- Energy export from Queensland into NSW (QNI being negative means flow from QLD into NSW) moderately declines as consumption growth in Queensland outpaces development of new generation and black coal generation reduces production due to competitive pressure from new renewable generation across the NEM.
- A significant trend is observed in the Victoria to NSW interconnector resulting from strong growth in renewable generation in Victoria somewhat supported by the VRET policy.

Figure 15: Average annual interconnector flows for Terranora, QNI and VIC_NSW (MW)

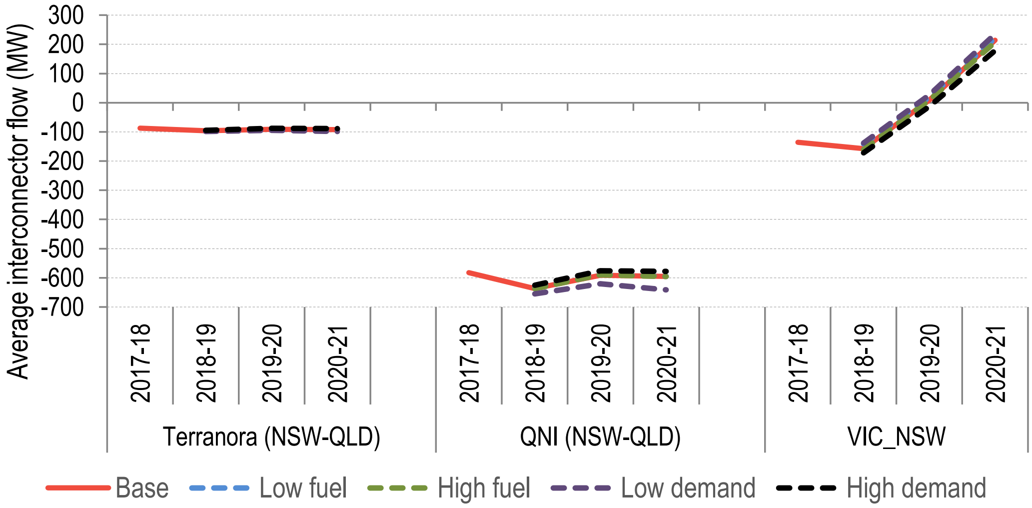
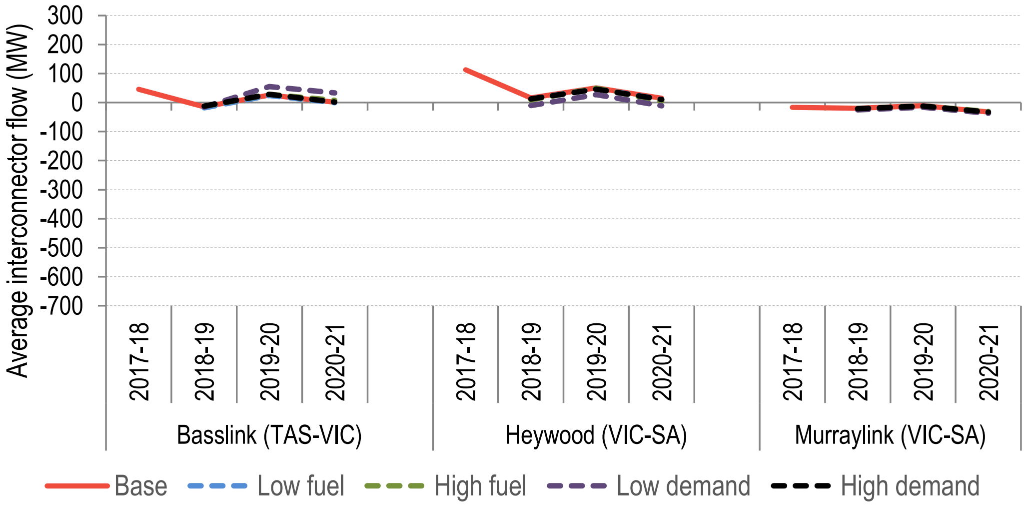


Figure 16: Average annual interconnector flows for Basslink, Heywood and Murraylink (MW)



5.7 Ancillary services cost

To estimate the future cost of ancillary services attributable to residential customer load we have examined AEMO's historical 2017 and 2018 financial year ancillary service settlement data published for each region of the NEM[14] and WEM[15]. For the NEM, linear trends were established in each region. In determining the trends in South Australia and Tasmania, outlier historical weeks that were deemed to obscure the underlying trend were removed before linear trends were established. Future weeks were extrapolated to 2020-21 and the financial years were averaged. For the WA WEM, market participant recovery rate principles are outlined in WEM Rules 3.14. The allocation rates are not published for the WEM and therefore to estimate the residential customer contribution, a simplifying assumption has been made that approximately 50% of all ancillary service costs are attributed to customers.

Table 5 shows the ancillary services fee for each region and year of the forecast period. The years highlighted show the historical data used to forecast the future ancillary services cost.

Table 5: Ancillary services cost $/MWh

Financial Year	NSW	QLD	VIC	SA	TAS	WEM
2016-2017	0.36	0.22	0.25	0.35	0.43	2.27
2017-2018	0.43	0.28	0.31	0.32	0.46	2.87
2018-2019	0.43	0.30	0.31	0.42	0.46	2.55
2019-2020	0.48	0.37	0.36	0.45	0.51	2.78
2020-2021	0.51	0.42	0.40	0.49	0.54	3.02

5.8 Market fees

Market fees are charged to market participants to recover the costs of operating the market. In the NEM, market fees are based on the operational expenditure of AEMO. In the WEM, market fees are based on the costs of AEMO, as well as the costs of the wholesale market functions of System Management and the Economic Regulation Authority.

Table 6 shows the estimated market fees based on budgets published by AEMO.[16] Budgeted fees for the WEM are provided for 2017-18[17] and 2018-19, future years have been estimated to escalate by 12% in line with the NEM budget.

Table 6: Market fees $/MWh

Financial Year	NEM	WEM
2017-2018	0.41	0.79
2018-2019	0.44	0.83
2019-2020	0.50	0.93
2020-2021	0.56	1.05

5.9 Large-scale Generation Certificate cost

The LGC subsidy for a renewable energy generator can be received in different ways, such as through selling LGCs directly on the LGC spot market or implicitly as an LGC contract price as part of a Power Purchase Agreement (PPA) contract bundling together the energy and LGC revenues for a generator.

EY has estimated the LGC contract price as the fair value of the subsidy required for a new entrant renewable generator entering into a PPA to recover its fixed and variable costs. The duration of this

[14] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Ancillary-Services/Ancillary-Services-Payments-and-Recovery

[15] https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf (Table 8)

[16] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Fees/2018/Final-AEMO-Electricity-Final-Budget-and-Fees-2018-19.pdf

[17] https://www.aemo.com.au/-/media/Files/About_AEMO/Energy_Market_Budget_and_Fees/2017/Consolidated-Budget-and-Fees-2017-18.pdf

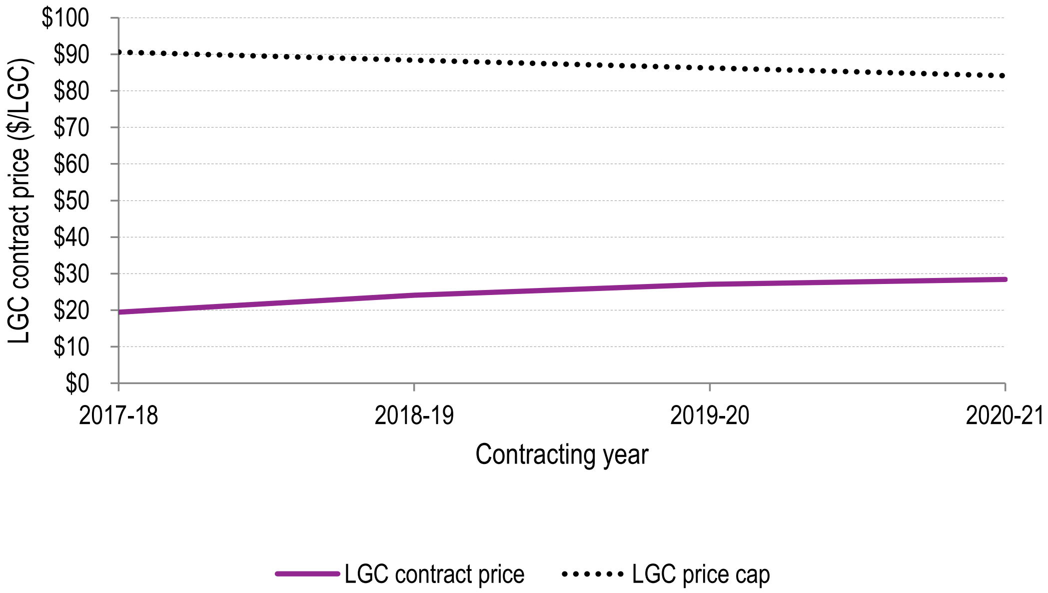
PPA is from the commissioning date until the end of LRET (2030), but for specific projects the total subsidy could be distributed over fewer years with a shorter PPA duration. The total LGC subsidy required by the marginal renewable generator is determined by taking the NPV of the fixed and variable costs (including capital costs) and subtracting the NPV of the projected average wholesale market revenue for the renewable project. The renewable technology requiring the lowest subsidy for a particular commissioning year is made the marginal generator and sets the LGC contract price. This technology is typically wind or single-axis tracking solar PV under current market conditions.

Only a small percentage of LGCs are traded on the spot market,[18] with most large-scale renewable projects entering into PPAs with retailers that include a bundled LGC price. The LGC spot price is subject to many different drivers that are completely de-coupled from the commercial drivers of LGC contract prices discussed above. LGCs are traded on the spot market in short-term quantities and thus pricing is influenced by the circumstances of those trades rather than long-term financing considerations. The LGC spot market has traditionally been thinly traded allowing the possibility for speculative trades to influence the price and as such LGC spot prices have been observed to change quickly following political announcements.

In the first half of the 2018 compliance year there was a shortfall of new LGCs being created in the market. As the surplus of banked certificates was being eroded and completion of new projects were delayed, this short-term shortfall resulted in LGC spot prices trading near the LGC price cap. Since the middle of 2018, LGC spot prices have decreased, as new projects are commissioned and new LGC creation is meeting the target.

Due to the long-term nature of PPAs signed by the majority of renewable developers, the average price received by the fleet of renewable projects for LGCs is likely to be higher than that of the marginal new entrant. The marginal new entrant price also may be insufficient for a renewable project in a different site or region, but such projects may be able to negotiate a higher LGC price based on other factors, such as planning, access to sites, etc.

Figure 17: Forecast LGC contract prices in the base scenario



[18] There is no central LGC spot market. However, there are a number of trading houses that offer the opportunity to trade these certificates and report the resulting price.

Table 7: Renewable Energy Target costs, LRET								
Compliance year	RPP estimate+ CAL year basis	FYE equivalent RPP	Estimated average cost of LGCs contracted*	Average cost of new LGCs+ (NEM modelling)	Weighted average of cost of LGCs+ (large retailer)	LRET wholesale cost component (large retailer)	LGC spot market price# (small retailer)	LRET wholesale cost component (small retailer)
		FYE basis values in $/MWh						
2021	19.24%	19.33%	40.00	28.43	40.30	**7.79**	19.25	**3.72**
2020	19.58%	19.16%	40.00	27.10	39.01	**7.47**	24.50	**4.69**
2019	17.90%	17.44%	40.00	24.11	38.67	**6.74**	70.75	**12.34**
2018	16.06%	15.68%	40.00	19.46	38.13	**5.98**	79.00	**12.38**

* Based on a broad estimate of historically published PPA prices and the effective residual value of LGCs considering energy market price
+ EY modelling
# spot price based on Mercari public website viewed 8 August 2018 http://lgc.mercari.com.au/

5.10 Small-scale Technology Certificate cost

Small-scale Technology Certificates (STCs) are created by registering the installation of new small generation units (SGUs). SGUs include small scale hydro, wind and solar PV generation facilities which are less than 100 kW in size. New installations of solar hot water systems are also eligible to create STCs. There is no annual target for STC liability like there is for the LRET policy. Similar to the RPP for LGCs, the liability for STC surrender is estimated annually as the Small-scale Technology Percentage (STP). The STP is calculated to follow the creation of STCs, rather than to meet a specified target. As there is no cap on the creation of STCs through installation of SGUs, the STP can vary from year to year and there is a mechanism to balance over- or under-estimated STC production in each subsequent year.

The Clean Energy Regulator (CER) provides a trading house service for trading STCs. Through the STC trading house sellers can register their STCs for sale and buyers can then purchase the STCs for a fixed price of $40 (ex GST) per certificate. Large buyers and sellers of STCs trade through bilateral contracts or over-the-shelf purchases of packages of STCs. The price for each certificate is determined largely by supply and demand conditions. In the recent past the creation of STCs has exceeded the projected STC liability leading to oversupply for each compliance period. As such large trades of STCs have occurred at a discount to the STC trading house default price and have been reported to be as low as $29/STC.[19] Over the past year STCs have traded between $35 and $40/STC for most of the time and therefore a reasonable estimate of large volume STC trades is considered to be approximately $35/STC.[19] As requested by the AEMC we make a distinction between large retailer entities and small retail entities. In relation to STC pricing, we assume large retail entities can procure their STC liability for $35/STC, whereas small retail entities generally procure their STC liability through the trading house at $40/STC.

The CER procures forecast modelling reports from time to time to estimate the future rate of creation of STCs.[20] Despite the depth of analysis provided the number of STCs that may be created in the future remains uncertain. To provide a wholesale cost estimate of SRES liability the creation of STCs is assumed to increase by 10% per annum. The STP calculation also includes a carry-over from a significant underestimate of STC creation from the previous 2017. Indications based on installations of SGUs to date in 2018 suggest creation in excess of the 2018 STP year is also likely. The STP calculation and subsequent SRES component of wholesale electricity cost estimate is presented in the table below.

[19] For example, based on public trading platforms such as http://www.demandmanager.com.au/certificate-prices/ and http://greenmarkets.com.au/resources/stc-market-prices. There are an increasing number of trading platforms.
[20] http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage/small-scale-technology-percentage-modelling-reports

Table 8: Renewable Energy Target costs, SRES						
Compliance year	STP estimate CAL year basis	FYE equivalent STP	Average STC cost+ (large retailer)	SRES wholesale cost component (large retailer)	STC clearing house price# (small retailer)	SRES wholesale cost component (small retailer)
		FYE basis values in $/MWh				
2021	20.58%	19.18%	35.00	**6.71**	40.00	**7.67**
2020	18.71%	19.37%	35.00	**6.78**	40.00	**7.75**
2019	19.59%	17.71%	35.00	**6.20**	40.00	**7.08**
2018	17.08%	9.72%	35.00	**3.40**	40.00	**3.89**

* Assuming large retailers can acquire large volumes of STCs at a discount, or produce STCs through sales of solar PV and accredited hot water systems

STC clearing house price for trades

5.11 Application of loss factors

Residential customer demand settlements that retailers are responsible for are subject to application of loss factors. Loss factors are calculated and published by AEMO annually[21] for each transmission connection point and distribution load area. Jurisdictional region average loss factors have been estimated by allocating transmission connection points to jurisdictional regions based on a geographical mapping exercise. Loss factors apply to electricity and LGC costs but not to STC costs.

In some areas, year-on-year transmission marginal loss factors (MLF) have increased by a small margin (<0.004), however the largest change in MLFs are reductions due to development of both small scale and large scale solar PV and wind generation projects throughout north-western Victoria (Powercor average MLF down by 0.026), New South Wales (Essential Energy average MLF down by 0.016, ActewAGL average MLF down by 0.01) and to a lesser extent Energex and SA Power Networks areas. Contrary to MLFs, distribution network loss factors (DLF) are generally on the rise compared with the previous year. The Western Power area DLF has increased by around 0.016 and Jemena jurisdiction DLF increased by 0.008.

Table 9: MLFs applied, all scenarios					
Area	Name	State	2017-18	2018-19	Year on year change
CountryEnergy	Essential Energy	NSW	1.0140	0.9976	-0.0164
EnergyAust	Ausgrid	NSW	1.0010	1.0020	0.0010
Integral	Endeavour Energy	NSW	0.9943	0.9950	0.0007
Energex	Energex Limited	QLD	1.0120	1.0050	-0.0070
Powercor	Powercor Australia Ltd	VIC	1.0352	1.0082	-0.0270
CitiPower	CitiPower Pty	VIC	1.0013	1.0009	-0.0004
United	United Energy Distribution Pty Ltd	VIC	1.0028	0.9984	-0.0044
VICAGL	Jemena Electricity Networks (Vic) Ltd	VIC	1.0030	1.0020	-0.0010
Ausnet	AusNet Services DNSP (formerly SP-Ausnet)	VIC	0.9864	0.9882	0.0018
ACTEWAGL	Actew Distribution Ltd and Jemena Networks (ACT) P	ACT	1.0400	1.0310	-0.0090
TasNetworks	AURORAP	TAS	0.9957	0.9993	0.0036
UMPLP	SA Power Networks	SA	1.0068	1.0014	-0.0054
Western Power	Western Power	WA	1.0384	1.0415	0.0031

[21] As calculated and published by AEMO annually: For the NEM https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries and for the WEM https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Loss-factors

Table 10: DLFs applied, all scenarios					
Area	Name	State	2017-18	2018-19	Year on year change
CountryEnergy	Essential Energy	NSW	1.0795	1.0745	-0.0050
EnergyAust	Ausgrid	NSW	1.0548	1.0544	-0.0004
Integral	Endeavour Energy	NSW	1.0649	1.0648	-0.0001
Energex	Energex Limited	QLD	1.0560	1.0534	-0.0026
Powercor	Powercor Australia Ltd	VIC	1.0686	1.0711	0.0025
CitiPower	CitiPower Pty	VIC	1.0419	1.0476	0.0057
United	United Energy Distribution Pty Ltd	VIC	1.0507	1.0533	0.0026
VICAGL	Jemena Electricity Networks (Vic) Ltd	VIC	1.0438	1.0526	0.0088
Ausnet	AusNet Services DNSP (formerly SP-Ausnet)	VIC	1.0618	1.0597	-0.0021
ACTEWAGL	Actew Distribution Ltd and Jemena Networks (ACT) P	ACT	1.0482	1.0467	-0.0015
TasNetworks	AURORAP	TAS	1.0351	1.0389	0.0038
UMPLP	SA Power Networks	SA	1.1050	1.1100	0.0050
Western Power	Western Power	WA	1.0482	1.0646	0.0164

Appendix A NEM modelling assumptions

A number of input assumptions are used to develop the price forecasts delivered in this report. An overview of WEM modelling assumptions is provided in this Appendix including;

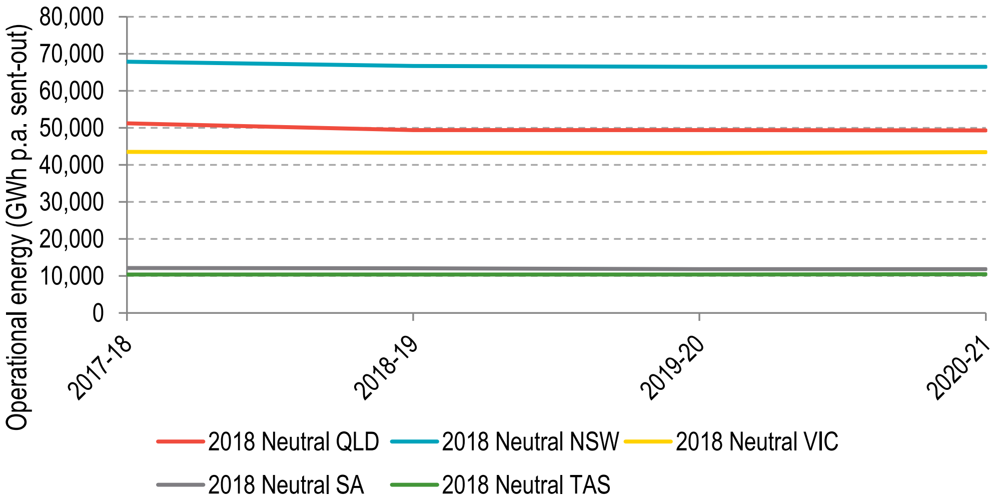
- Electricity consumption and peak demand
- Load profiles
- Rooftop PV and behind-the-meter battery uptake
- Electric vehicles
- Thermal generation developments
- Renewable capacity developments
- Fuel costs, and
- Interconnector flow

A.1 Electricity consumption

One of the primary considerations when forecasting the electricity market is the future electricity consumption. Between 1999-00 and 2008-09 electricity consumption increased year on year in all regions of the NEM except for South Australia. From 2008-09 to 2013-14 consumption decreased year on year in all regions NEM with only a few exceptions. There are a number of factors that lead to this outcome including price sensitivity of electricity consumers, the uptake of rooftop PV, and the improved energy efficiency of many electricity consuming devices. Since 2013-14 there has been consistent growth in annual consumption in Queensland and New South Wales, falling annual consumption in Victoria and no significant change in annual consumption in South Australia or Tasmania.[22]

Figure 18 shows AEMO's forecast electricity consumption from the 2018 ESOO.[23]

Figure 18: AEMO's Neutral scenario forecast of annual regional energy consumption in the NEM



[22] Annual consumption by region is available at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/electricity-supply-to-regions-of-the-national-electricity-market

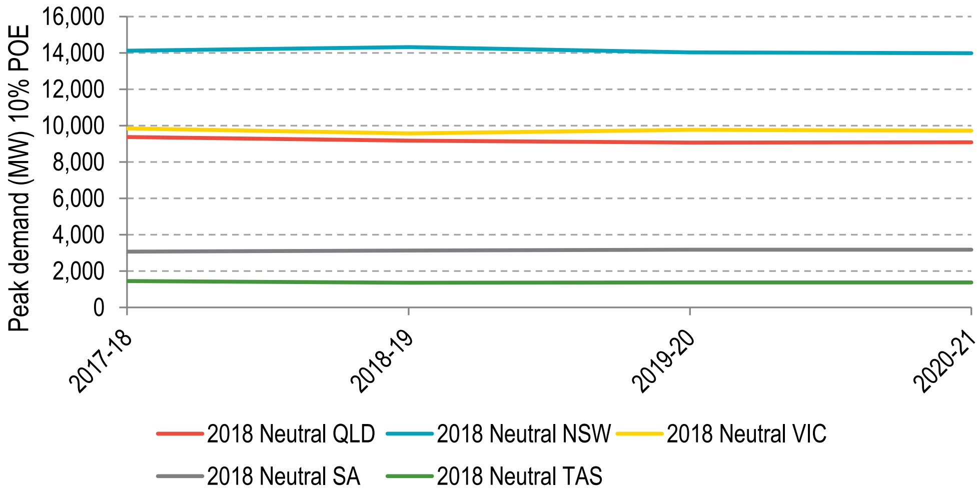
[23] Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

A.2 Peak demand

The future peak demand for electricity is influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. Peak demand and near-peak demand events are often associated with high wholesale electricity prices and extreme price volatility, and as a result the magnitude of the peak demand in any given year is a material factor in determining overall wholesale market prices. EY uses two of AEMO's published peak demand forecasts representing a 10% probability of exceedance (POE) and an average (50% POE) peak demand level. The 50% POE peak represents a typical year, with a one in two chance of the peak demand forecast being exceeded in at least one half hour of the year. The 10% POE peak demand represents a high demand outcome with a one in ten chance of the peak demand forecast being exceeded in at least one half hour of the year. EY simulates both targets and creates weighted-average results.

Figure 19 below shows the regional annual peak demand in the NEM for the 10% POE projection used in this scope of work from the Neutral economic growth scenario from AEMO's 2018 ESOO. Figure 19 shows that there is a slight increase in forecast peak demand in New South Wales and South Australia.

Figure 19: AEMO's Neutral annual 10% POE regional peak demand forecast in the NEM



A.3 Load profiles

AEMO provides a number of load profiles for determining the amounts owed by retailers servicing customers on accumulation meters. For this task, we would apply the Net System Load Profile (NSLP) profiles, both "basic" and "with peel-off" and the Controlled Load Profiles (CLP).

We use these profiles to determine the shape of demand for a typical residential customer in each region. Given that the shape of regional demand is changing over the duration of this forecast period, primarily as a result of rooftop PV and energy efficiency measures in the household, our approach would also modify the shape of the demand for the typical customer over time.

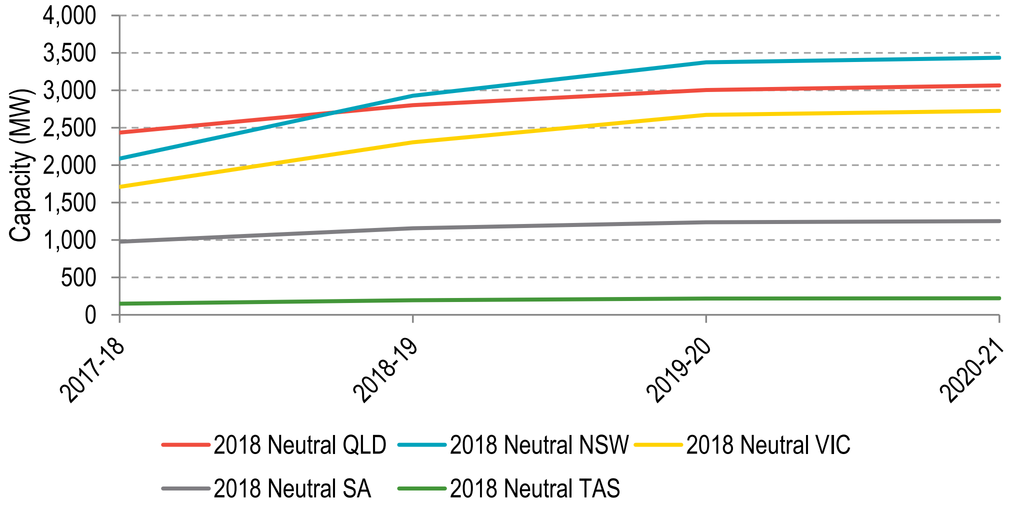
To determine the expected wholesale market cost, we then multiply the load profile for the typical residential customer in each jurisdiction by the half-hourly prices in each year. In this way, we conserve the relationship between the level of demand from the typical residential customer and wholesale market pool prices.

A.4 Commercial and residential rooftop PV systems

The uptake in rooftop PV systems in recent years has been rapid in all states, driven by favourable government policies and attractive payback periods. While many of the supportive government policies have now been removed (or significantly scaled back), AEMO still expects significant growth in rooftop PV uptake due to decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs.

Figure 20 shows the rooftop PV trajectory used in this scenario, which is based on the underlying conditions of AEMO's Neutral scenario from the 2018 AEMO ESOO.

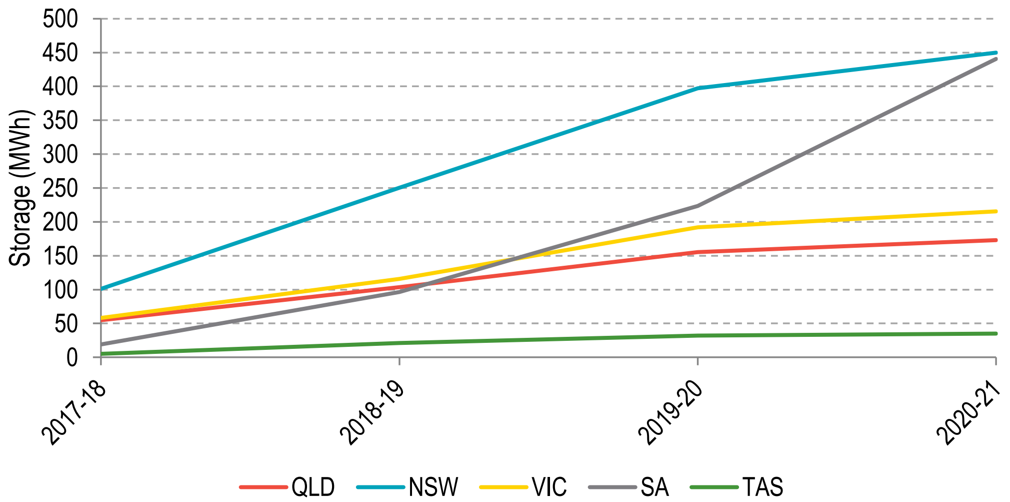
Figure 20: AEMO Neutral installed rooftop PV capacity forecast for the NEM



A.5 Behind-the-meter storage uptake

AEMO's behind-the-meter battery storage uptake from the 2018 AEMO ESOO are shown in the figure below. These batteries are assumed to be installed in households and in the commercial sector, in most cases in conjunction with a rooftop PV systems. Large-scale storage would be in addition to these installations. Figure 21 shows the assumed uptake of behind-the-meter storage in each region. The projected uptake of behind the meter storage is very small compared with the scale of the market. As such the influence of this input assumption on the wholesale electricity market price projections is immaterial in the forecast period.

Figure 21: Behind-the-meter battery storage uptake trajectory per region from AEMO's 2018 ESOO Neutral scenario

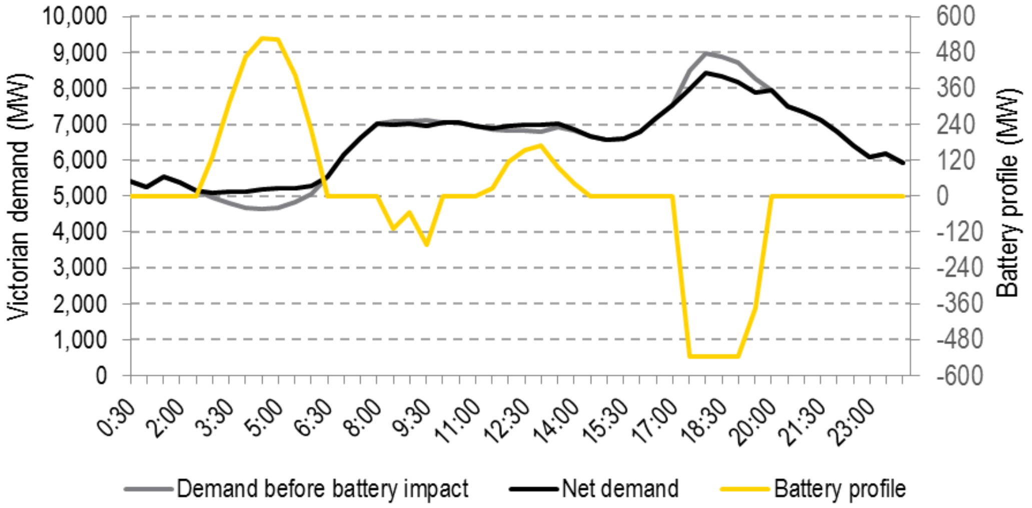


EY's behind-the-meter battery storage profile tool produces a seasonal time-of-day charge and discharge profile for behind-the meter battery storage for each region. The tool aims to produce an aggregate profile that responds to peak demand usage tariffs and lower priced daytime effective tariffs due to battery owners also owning rooftop PV systems. Rather than assuming a particular retail tariff structure for future battery owners, it is assumed that the tariffs will relate to the net demand profile on the distribution network – consumption minus rooftop PV generation. As a result the tool produces a fixed time-of-day discharge profile that reduces the seasonal peak net demand and a charge profile that operates during the lowest periods of residual demand. To incorporate imperfection into the aggregated profile of the batteries, EY has assumed the following two factors that are applied in the profile algorithm:

- Total energy charge discount factor: **85%**. To account for the likelihood that battery owners won't fully charge their batteries every day (due to faults, performance degradation, etc.), EY limits the daily charge to 85% of the total installed energy capacity.
- Coincident charge/discharge discount factor: **70%**. This factor accounts for faults, coordination and the potential for different tariff signals to lead to batteries never being charged or discharged at the same time. EY limits the maximum charge or discharge to 70% of the total charge/discharge capacity in MW.

Figure 3 below illustrates an example day in winter on how the aggregate battery charge and discharge cycle alters the operational demand profile.

Figure 22: Example day showing impact of behind-the-meter battery storage on operational demand in Victoria



This behind-the-meter storage profile is added/subtracted to the operational demand for 2-4-C® modelling.

A.6 Large-scale renewable energy target

In June 2015 the Commonwealth Government legislated the revised LRET, ending a protracted review of the policy.

The current legislated targets require 33,000 GWh per annum of eligible renewable energy from 2020 to 2030, as illustrated in Figure 23. Additional voluntary certificate surrenders are also expected, due to several state or territory policies, as well as consumer choice schemes such as the GreenPower program.

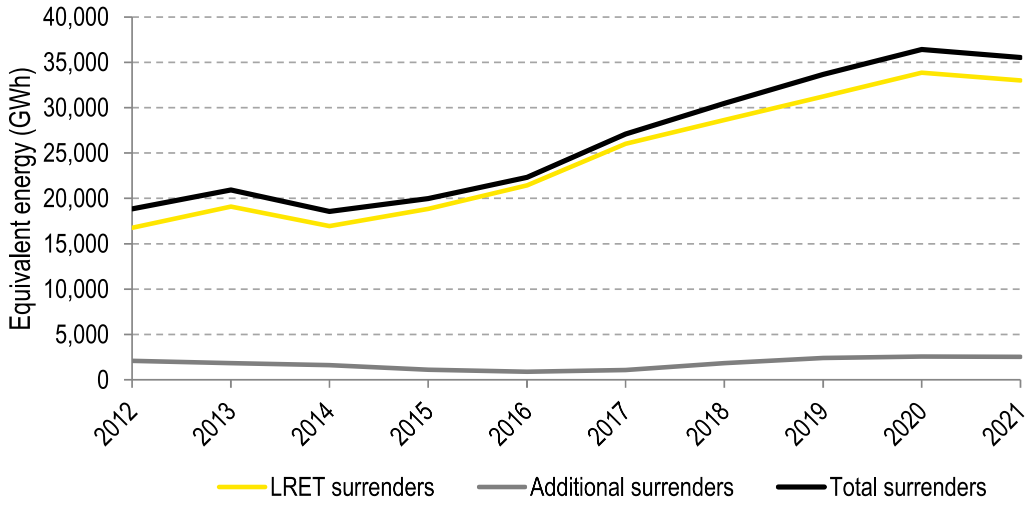
The modelling also includes the announced projects under the 928 MW auction of the Victorian Renewable Energy Target[24] and the announced 400 MW Queensland reverse auction.[25] Both

[24] https://www.tenders.vic.gov.au/tenders/tender/display/tender-details.do?id=10167&action=display-tender-details

[25] http://statements.qld.gov.au/Statement/2017/8/28/renewables-400-program-charging-ahead-with-huge-interest. Along with the 400 MW of renewable capacity, EY has included the stipulated 100 MW of battery storage in Queensland as part of this initiative.

schemes are designed to be complementary to LRET, i.e., it will not create additional demand for LGCs on the national level.

Figure 23: Large-scale renewable energy target trajectory



A.7 Emissions reduction policy

The introduction of the Emissions Reduction Fund and Safeguard Mechanism from the Coalition Government are currently the key policy settings (with the renewable energy policies) to drive decarbonisation of the electricity sector to contribute to Australia's emissions abatement targets. In recent years there has been many proposed emissions reduction schemes. Despite these developments, there is uncertainty as to what, if any, emission reduction policy will be implemented in Australia in the foreseeable future, and what the level of emissions reductions will be targeted.

In December 2015 at the UNFCC[26] COP21 Paris Climate Conference, the Australian Government committed to a 26-28% reduction in emissions below 2005 levels by 2030. As a result, policy development is expected to support increased decarbonisation efforts.

It is assumed that even if a national emissions reduction scheme is implemented over the forecast period for 2018 Price Trends, the targets that may be set in this period will not represent a major change and will not require additional investment to that which is currently assumed in the wholesale modelling. Therefore no explicit consideration of an implicit or explicit carbon price is included in the wholesale market modelling.

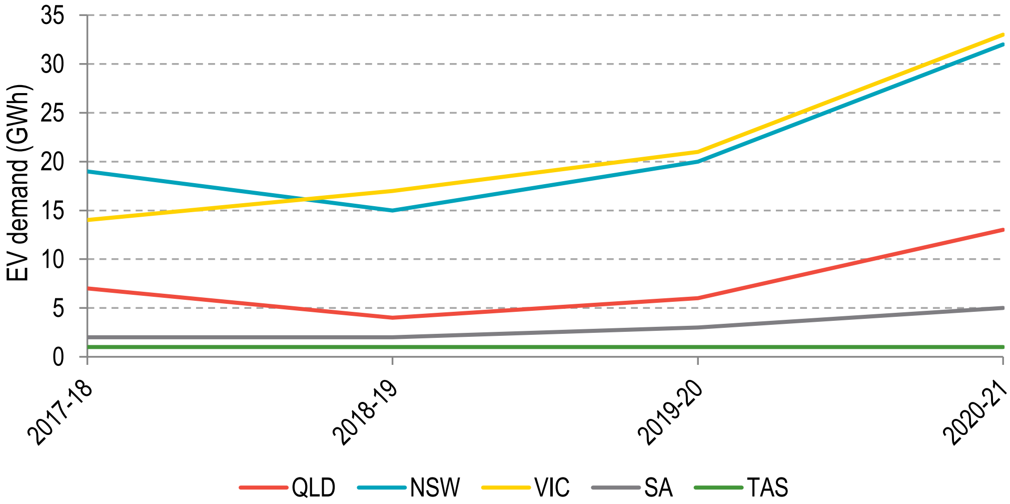
A.8 Impact of electric vehicles

The scenario considers an uptake of electric vehicles providing a new source of electrical load as consumers switch from petrol-based vehicles to those that rely on charging from the grid.

The energy impact based on the AEMO 2018 ESOO for electric vehicles is shown in Figure 34 below. The projected consumption of EV's is relatively small compared with the scale of the market. Furthermore, the time of charging demand on the network and influence on wholesale market prices is uncertain but likely to be somewhat spread out. As such the influence of this input assumption on the wholesale electricity market price projections is very small in the forecast period.

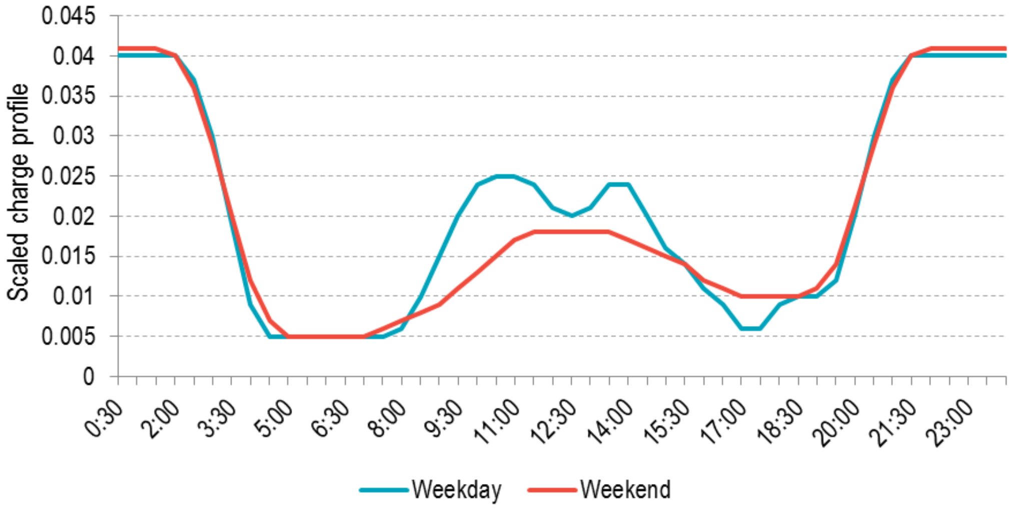
[26] United Nations Framework Convention on Climate Change

Figure 24: Electric vehicle energy demand



To model the half-hourly load from EVs, EY has constructed two bespoke time-of-day demand profiles, one for weekdays and one for weekends, as shown in Figure 25. We assume that overnight charging rolls off early in the morning, followed by an extended low period during the morning period of high electricity demand and commuting activity. Charging then increases again after people arrive at their destinations, and persists throughout the day before decreasing again in the afternoon when commuting activity commences again. Overnight charging commences significantly after the evening peak demand driven by time-of-use and peak demand tariff signals.

Figure 25: Percentage of daily energy use for electric vehicles in each half-hour of the day



A.9 Thermal generation developments

Due to a modest energy growth outlook as per the AEMO 2018 ESOO Neutral scenario and increasing competition from renewable projects to meet the LRET, retirement or mothballing (temporary removal from service) of thermal generation is likely over the modelled period. Table 11 lists the mothballing assumed in these scenarios.

Table 11: Announced mothballing

Power station	Region	Type	Capacity (MW)	Timing	Comments
Torrens Island A	SA	Gas - Steam	480 /240	1/07/2019 (reduced capacity)	AGL has announced that Torrens Island A power station needs to be "replaced" soon. http://www.abc.net.au/news/2017-06-07/agl-announces-new-sa-power-station/8596016

A list of announced new development (non-wind/solar) are also shown in Table 12.

Table 12: Announced new developments (non-wind/solar)				
Power station	Region	Capacity	Technology	Timing
SA Gov OCGT peaker	SA	276	OCGT extreme peaker	1/12/2017
Barker Inlet Power Station	SA	210	Compression Reciprocating Engine	1/07/2019
Loy Yang B upgrade	VIC	80	Brown Coal	1/7/2019 1/7/2020
SA Gov 100 MW battery (100 MW / 129 MWh)	SA	30 MW / 39 MWh[27]	Storage	1/01/2018
Ballarat 30 MW battery	VIC	30 MW/ 30 MWh	Storage	1/12/2018
Gannawarra 25 MW battery	VIC	25 MW/ 54 MWh	Storage	1/12/2018
Neoen Bulgana 20 MW battery	VIC	20 MW / 34 MWh	Storage	1/07/2018
Qld Gov 100 MW battery	QLD	100 MW / 100 MWh	Storage	1/07/2019

Furthermore, AGL announced up to 2650 MW of new developments to replace Liddell.[28] Those new developments that occur within the forecast period are listed in Table 13. The remaining development is expected to occur outside of the reporting period.

Table 13: AGL Announced new developments (non-wind/solar)				
Power station	Region	Capacity	Technology	Timing
Demand response	NSW	100 MW	Storage	From 1/07/2020 in stages (20 MW in 1/07/2020, 50 MW in 1/07/2021 and 30 MW in 1/07/2022)

A.10 Renewable generation

The renewable build will be driven by the LRET during the forecast period. The renewable generation development schedule is listed in Table 14.

Table 14: Schedule of renewable energy generation development				
Project	Region	Capacity (MW)	Technology	Year installed
CHALLHWF	VIC	52.5	Wind	Existing
STARHLWF	SA	34.5	Wind	Existing
WOOLNTH1	TAS	139.75	Wind	Existing
CNUNDAWF	SA	46	Wind	Existing
LKBONNY1	SA	80.5	Wind	Existing
WPWF	SA	90.75	Wind	Existing
CATHROCK	SA	66	Wind	Existing
MTMILLAR	SA	70	Wind	Existing
YAMBUKWF	VIC	30	Wind	Existing
LKBONNY2	SA	159	Wind	Existing
PORTWF	VIC	149.2	Wind	Existing
SNOWTWN1	SA	100.8	Wind	Existing
HALLWF1	SA	94.5	Wind	Existing
WAUBRAWF	VIC	192	Wind	Existing
CAPTL_WF	NSW	140.7	Wind	Existing
CLEMGPWF	SA	56.7	Wind	Existing
CULLRGWF	NSW	30	Wind	Existing
HALLWF2	SA	71.4	Wind	Existing
LKBONNY3	SA	39	Wind	Existing

[27] The SA Government has dispatch rights for 70 MW of the 100 MW battery. As such, 30 MW of the 100 MW battery is assumed to be available for the purpose of assessing the impact of the SA battery on the wholesale market.
[28] https://www.agl.com.au/-/media/agl/about-agl/documents/media-center/asx-and-media-releases/2017/171209nswgenerationplandecember2017.pdf?la=en&hash=529E1A89370A33DA8F378D761CEEF1D919C9C91D

Table 14: Schedule of renewable energy generation development				
Project	Region	Capacity (MW)	Technology	Year installed
BLUFF1	SA	52.5	Wind	Existing
GUNNING1	NSW	46.5	Wind	Existing
NBHWF1	SA	132.3	Wind	Existing
OAKLAND1	VIC	63	Wind	Existing
WATERLWF	SA	111	Wind	Existing
WOODLWN1	NSW	48.3	Wind	Existing
MACARTH1	VIC	420	Wind	Existing
MLWF1	VIC	19.5	Wind	Existing
MUSSELR1	TAS	168	Wind	Existing
BOCORWF1	NSW	113	Wind	Existing
GULLRWF1	NSW	165	Wind	Existing
MERCER01	VIC	131	Wind	Existing
SNOWNTH1	SA	144	Wind	Existing
SNOWSTH1	SA	126	Wind	Existing
TARALGA1	NSW	106.7	Wind	Existing
BALDHWF1	VIC	106.6	Wind	Existing
BROKENH1	NSW	53	Solar PV - Fixed	Existing
MOREESF1	NSW	56	Solar PV - SAT	Existing
NYNGAN1	NSW	102	Solar PV - Fixed	Existing
ARWF1	VIC	80.5	Wind	Existing
HDWF1	SA	100	Wind	Existing
WATERLWF	SA	19.8	Wind	Existing
ARWF1	VIC	160	Wind	Existing
CLARESF1	QLD	100	Solar PV - SAT	Existing
GULLRSF1	NSW	10	Solar PV - Fixed	Existing
HDWF2	SA	102.4	Wind	Existing
KIATAWF1	VIC	31.05	Wind	Existing
MLSP1	NSW	13	Solar PV - SAT	Existing
Oakey Solar Farm_S1	QLD	25	Solar PV - SAT	Existing
PARSF1	NSW	50	Solar PV - SAT	Existing
STWF1	NSW	100	Wind	Existing
WRWF1	NSW	175	Wind	Existing
Bannerton Solar Park	VIC	88	Solar PV - Fixed	1/07/2018
Bodangora	NSW	113.2	Wind	1/07/2018
Bulgana	VIC	194	Wind	1/07/2018
Bungala_S1	SA	137.8296	Solar PV - SAT	1/07/2018
Childers	QLD	75	Solar PV - SAT	1/07/2018
Clermont Solar Farm	QLD	75	Solar PV - Fixed	1/07/2018
Collinsville Solar Power Station	QLD	42.5	Solar PV - SAT	1/07/2018
Darling Downs Solar Farm	QLD	110	Solar PV - Fixed	1/07/2018
Daydream Solar Farm	QLD	150	Solar PV - SAT	1/07/2018
Dubbo Solar Farm	NSW	24.2	Solar PV - SAT	1/07/2018
GANNSF1	VIC	55	Solar PV - SAT	1/07/2018
Griffith Solar Farm	NSW	34.9424	Solar PV - SAT	1/07/2018
Hamilton Solar Farm	QLD	57.5	Solar PV - SAT	1/07/2018
Haughton Solar Farm	QLD	100	Solar PV - SAT	1/07/2018
Hayman Solar Farm	QLD	50	Solar PV - SAT	1/07/2018
HDWF3	SA	109	Wind	1/07/2018
Karadoc	VIC	90	Solar PV - SAT	1/07/2018
KSP1	QLD	50	Solar PV - SAT	1/07/2018
Lilyvale Solar Farm	QLD	100	Solar PV - SAT	1/07/2018
Lincoln Gap	SA	212	Wind	1/07/2018
LRSF1	QLD	15	Solar PV - SAT	1/07/2018
Manildra Solar Farm	NSW	46.7	Solar PV - SAT	1/07/2018

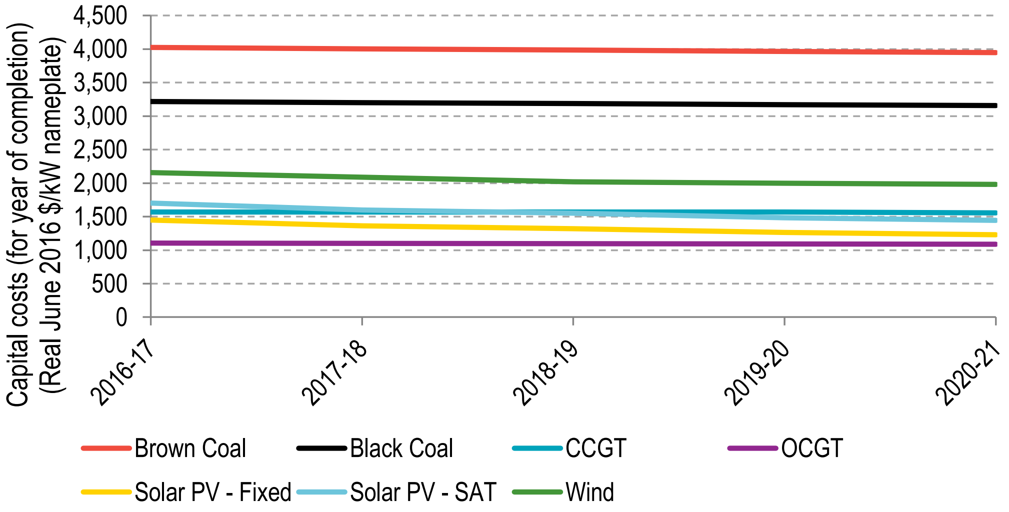
Table 14: Schedule of renewable energy generation development				
Project	Region	Capacity (MW)	Technology	Year installed
Mount Emerald	QLD	180.5	Wind	1/07/2018
Mount Gellibrand	VIC	132	Wind	1/07/2018
Numurkah_S1	VIC	38	Solar PV - SAT	1/07/2018
Oakey Solar Farm_S2	QLD	55	Solar PV - SAT	1/07/2018
Ross River Solar Farm	QLD	116	Solar PV - SAT	1/07/2018
Salt Creek	VIC	54	Wind	1/07/2018
SAPHWF1	NSW	270	Wind	1/07/2018
STWF1	NSW	100	Wind	1/07/2018
Sun Metals solar project	QLD	125	Solar PV - SAT	1/07/2018
Susan River	QLD	98	Solar PV - SAT	1/07/2018
Tailem Bend Solar Project	SA	100	Solar PV - SAT	1/07/2018
Wemen	VIC	87.5	Solar PV - Fixed	1/07/2018
White Rock Solar Farm	NSW	20	Solar PV - Fixed	1/07/2018
Whitsunday Solar Farm	QLD	57.5	Solar PV - SAT	1/07/2018
Willogoleche Hill	SA	119	Wind	1/07/2018
Yarranlea Solar Farm	QLD	100	Solar PV - SAT	1/07/2018
Yatpool	VIC	81	Solar PV - Fixed	1/07/2018
Beryl Solar Farm	NSW	87	Solar PV - SAT	1/07/2019
Cattle Hill_S1	TAS	144	Wind	1/07/2019
Chinchilla	QLD	16.7	Solar PV - SAT	1/07/2019
Coleambally	NSW	150	Solar PV - SAT	1/07/2019
Coopers Gap	QLD	453	Wind	1/07/2019
Crookwell 2	NSW	91	Wind	1/07/2019
Crowlands	VIC	80	Wind	1/07/2019
Crudine Ridge	NSW	135	Wind	1/07/2019
Emerald Solar	QLD	68	Solar PV - SAT	1/07/2019
Granville Harbour_S1	TAS	112	Wind	1/07/2019
Hughenden Sun Farm	QLD	20.1617	Solar PV - Fixed	1/07/2019
Kennedy Energy Park	QLD	15	Solar PV - SAT	1/07/2019
Kennedy_S1	QLD	43.2	Wind	1/07/2019
Kiamal	VIC	200	Solar PV - SAT	1/07/2019
Lal Lal_S1	VIC	228	Wind	1/07/2019
Moorabool_S1	VIC	150	Wind	1/07/2019
Murra Warra	VIC	226	Wind	1/07/2019
Numurkah_S2	VIC	62	Solar PV - SAT	1/07/2019
Rugby Run	QLD	65	Solar PV - SAT	1/07/2019
Stockyard Hill	VIC	536	Wind	1/07/2019
Sunraysia	NSW	200	Solar PV - SAT	1/07/2019
Warwick Solar Farm	QLD	64	Solar PV - SAT	1/07/2019
Aurora_S1	SA	150	Solar tower	1/07/2020
Berrybank_S1	VIC	180	Wind	1/07/2020
Bungala_S2	SA	86	Solar PV - SAT	1/07/2020
Carwarp	VIC	100	Solar PV - SAT	1/07/2020
Cohuna	VIC	27.3	Solar PV - SAT	1/07/2020
Dundonnell	VIC	336	Wind	1/07/2020
Mortlake South	VIC	157.5	Wind	1/07/2020
Shepparton Solar Farm_S1	VIC	100	Solar PV - SAT	1/07/2020
Snowtown North Solar Farm_S1	SA	44	Solar PV - SAT	1/07/2020
Winton	VIC	85	Solar PV - SAT	1/07/2020

In all scenarios the LRET is met by the plant above. No further capacity has been installed on an economic basis during the forecast period.

A.11 New entrant capital costs

EY has based their technology costs on projections developed by AEMO, as published in the 2016 NTNDP report[29]. Solar PV and Wind capital costs have been reduced, in line with views developed from industry consultation. The capital costs for other technologies have remained unchanged. Figure 26 shows the capital costs projections for key technologies.

Figure 26: New entrant capital costs assumed for different technologies



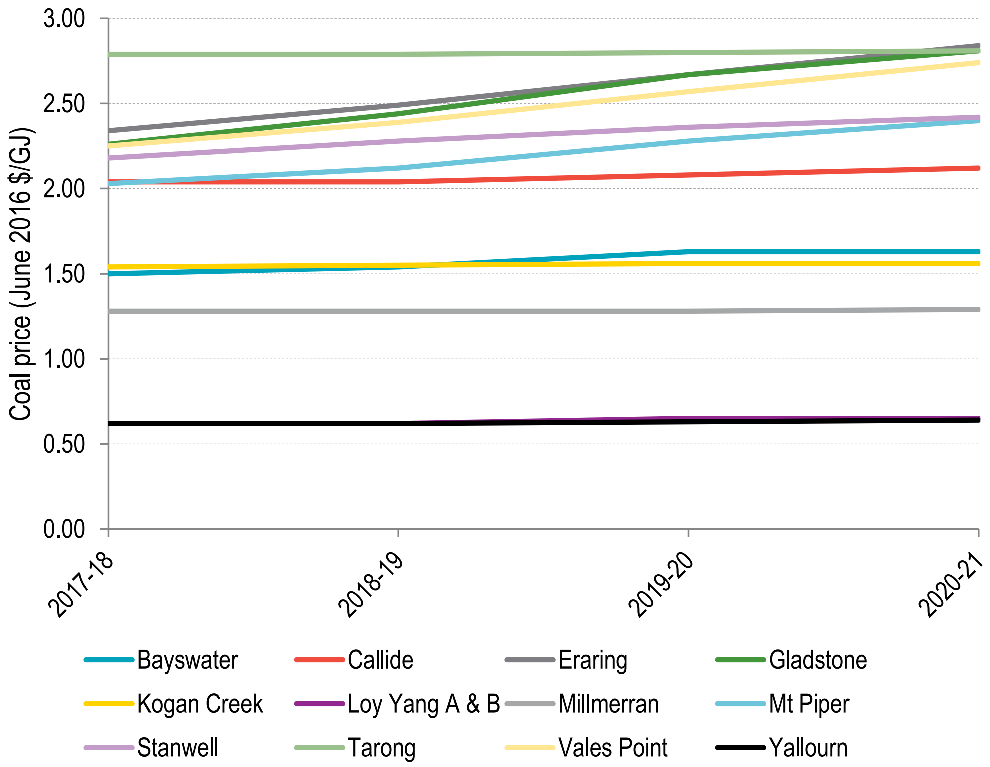
A.12 Coal prices

Figure 27 shows the assumed coal prices used in the modelling for the existing coal power stations. Coal prices are based on AEMO's 2018 ISP, which have been derived by AEMO based on wholesale coal price forecasts produced by Core Energy and Wood Mackenzie.[30] The wholesale prices reflect underlying market conditions assumed in each forecast scenario.

[29] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan and http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database

[30] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/ISP-Appendices_final.pdf

Figure 27: Coal prices for current operating power stations as published by AEMO

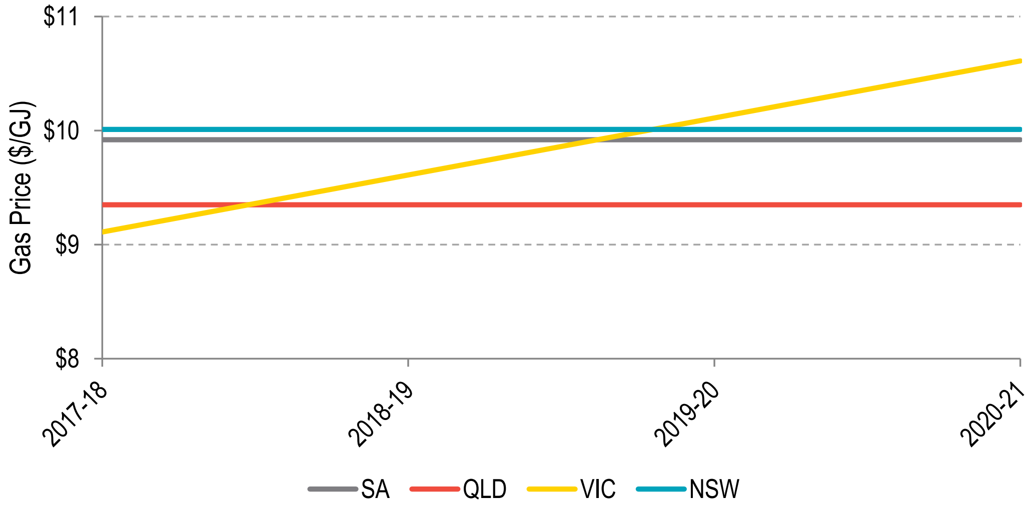


A.13 Gas prices

The price for natural gas is a key influence on market prices, influencing the bidding of gas fired generators. We do not consider the impacts of short-term gas contracts in our modelling, rather considering the pricing effect of long-term gas contracts for gas powered generators. Gas prices are based on AEMO's 2018 ISP, which have been derived by AEMO based on Core Energy Gas Pricing Consultancy Databook (March 2017 Update).[31] The wholesale prices reflect underlying market conditions assumed in each forecast scenario. Figure 28 below shows the assumed gas price trajectory in for uncontracted gas supplies. As existing gas generators' current gas contracts roll off, EY expects that these generators will be forced to adopt this price trajectory for their future gas contracts due to the nature of significant development in the global LNG export market now serviced out of Queensland which can be accessed through the east coast gas pipeline network. AEMO's 2018 GSOO[32] states that multiple reviews of the Victorian gas market support the "need for reserves and resources not yet developed to be brought to market in the short term to meet forecast demand" and this is reflected in the forecast for increasing gas price in the Victoria region.

[31] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/ISP-Appendices_final.pdf
[32] https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities pp11, section 1.3.

Figure 28: Forecast gas prices for the capitals in each region (from 2018 ISP) - Neutral case



A.14 Interconnectors and network constraints

No interconnector upgrades are considered in the scenarios modelled. EY models the interconnector limits with the appropriate loss equations and limits.

A subset of AEMO's 2016 planning network constraint equation data set has been used in this modelling for intra-regional network constraints. These consist of primarily thermal constraint equations involving transmission limitations plus some stability constraint equations to further capture the major interconnector limitations between the regions.

Appendix B WEM modelling assumptions

A number of input assumptions are used to develop the price forecasts delivered in this report. An overview of WEM modelling assumptions is provided in this Appendix including:

- Electricity consumption and peak demand
- Reserve capacity target
- Rooftop PV and behind-the-meter battery uptake
- Electric vehicles
- Thermal generation developments
- Renewable capacity developments
- Fuel costs, and
- Marginal loss factors

The AEMC requested that wholesale costs in WA be considered using two approaches, a market modelling approach similar to the NEM including reserve capacity and electricity balancing market cost, and also with a long run marginal cost (LRMC) approach to calculating total wholesale market costs.

B.1 Electricity consumption and peak demand

One of the primary considerations when forecasting the electricity market is the future electricity consumption and peak demand. EY used data based on the WEM 2018 ESOO as the source of electricity demand and energy projections. Figure 29 shows this expected trajectory in the WEM 2018 ESOO annual operational energy consumption (to be met by large-scale Registered Facilities).

Figure 29: WEM 2018 ESOO annual operational energy forecast in the WEM

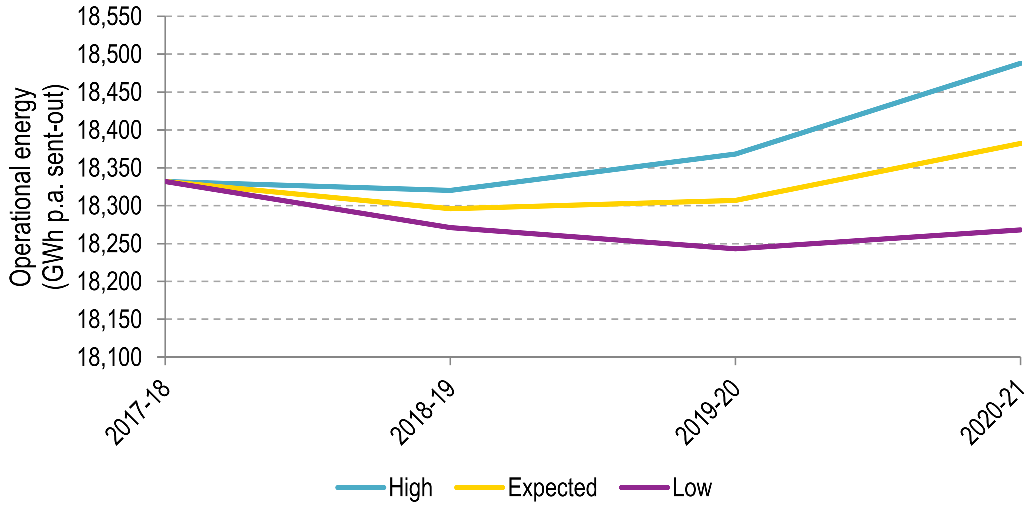
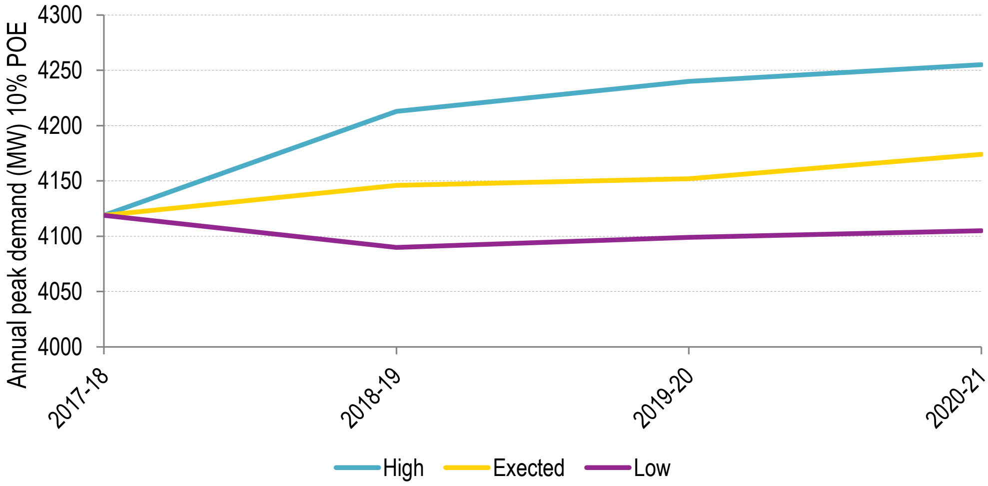


Figure 30 shows the regional peak demand in the WEM for the 10% POE projection.

Figure 30: WEM 2018 ESOO annual 10% POE regional peak demand forecast in the WEM

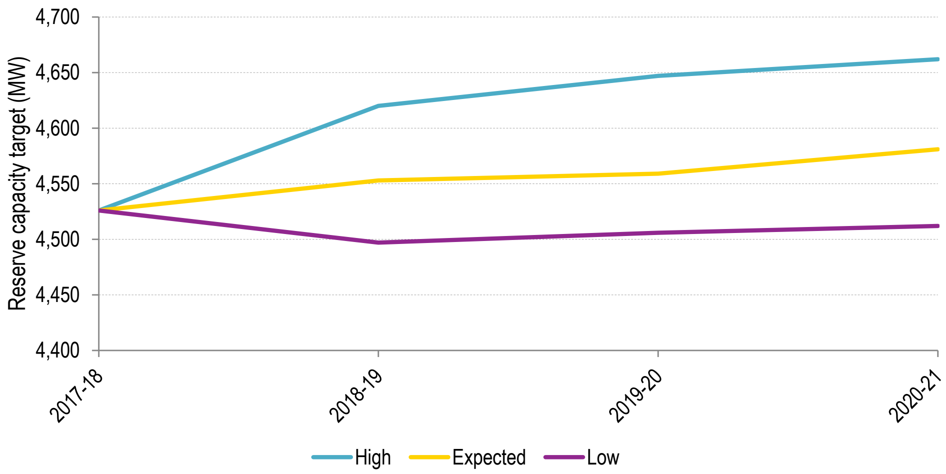


Peak demands are materially influenced by weather conditions, particularly hot temperatures in summer and cold temperatures in winter, driving cooling and heating air conditioning loads, respectively. The peak demand (and near-peak demand conditions) increases the risk of price volatility, and therefore the magnitude of the peak demand in any given year is a material factor in determining overall wholesale market pricing trends. Peak demand periods are also typically periods where network constraint equations bind. The 10% POE and 50% POE peak demand levels forecast by AEMO is modelled based on the WEM 2018 ESOO. The 50% POE peak represents a typical year, with a one in two chance of the peak demand being exceeded in at least one half hour of the year. The 10% POE peak demand represents a one in ten chance of being exceeded in at least one half hour of the year.

B.2 Reserve capacity target

Figure 31 shows the forecast RCT under the Expected, Low and High 10% POE peak demand trajectories for the WEM based on the WEM 2018 ESOO. It has been assumed that the contribution to the RCT requirement from intermittent loads, reserve margins and load following remains constant under the each of the scenarios. The RCT sets the RCR for the relevant Capacity Year.

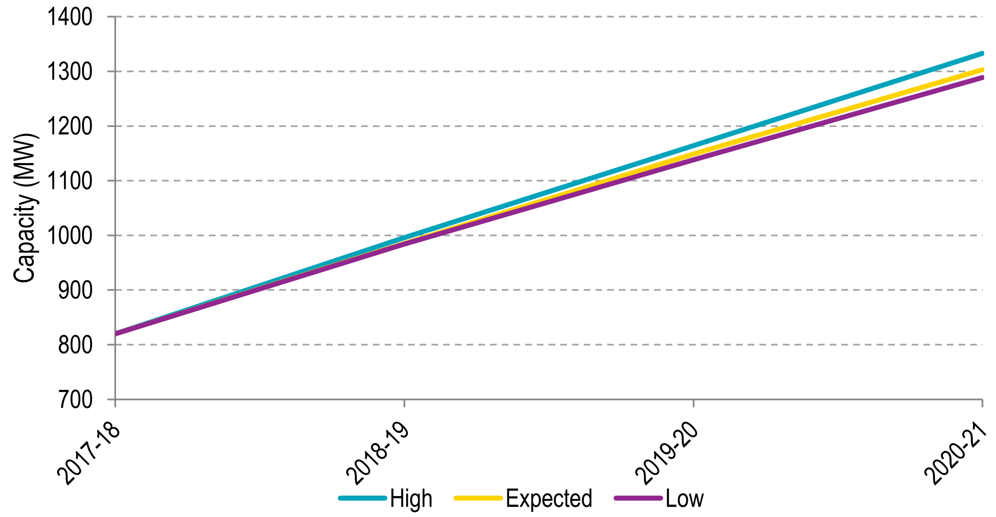
Figure 31: Calculated Reserve Capacity Targets for each WEM 2018 ESOO scenario



B.3 Commercial and residential rooftop PV systems

The uptake in rooftop PV systems has been rapid in the WEM, driven by favourable government policies and attractive payback periods. While many of the supportive government policies have now been removed (or significantly scaled back), AEMO still forecasts significant growth in rooftop PV uptake assumed to be driven by decreasing costs of PV systems and increasing (real or customer perceived) retail energy costs. Figure 32 shows the rooftop PV trajectory for the Expected, High and Low scenarios.

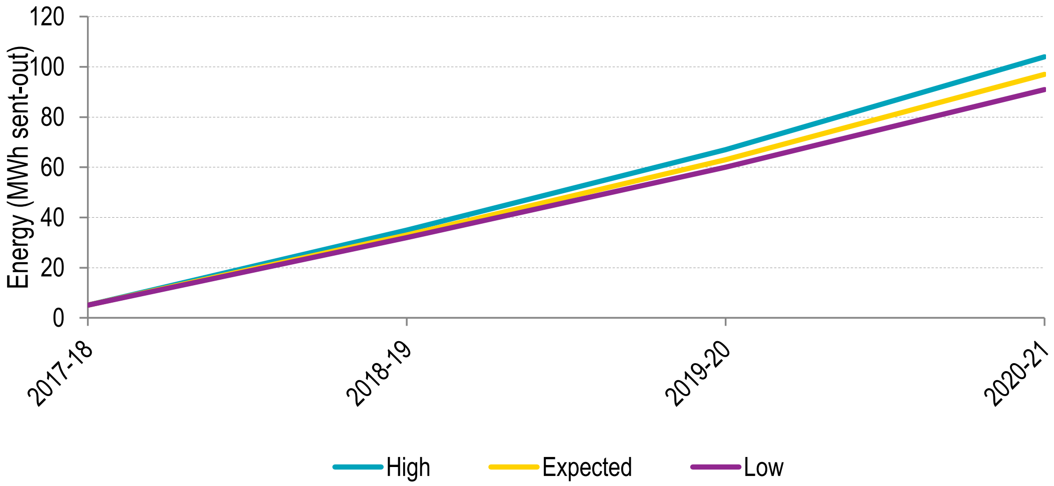
Figure 32: Projections for installed rooftop PV capacity forecast for the WEM for each WEM 2018 ESOO scenario



B.4 Behind-the-meter storage uptake

EY will use AEMO's behind-the-meter battery storage uptake from the WEM 2018 ESOO. These batteries are assumed to be installed in households and in the commercial sector, in most cases in conjunction with a rooftop PV systems. Large-scale storage would be in addition to these installations. Figure 33 for an example shows the uptake of behind-the-meter battery storage from each WEM 2018 ESOO scenario.

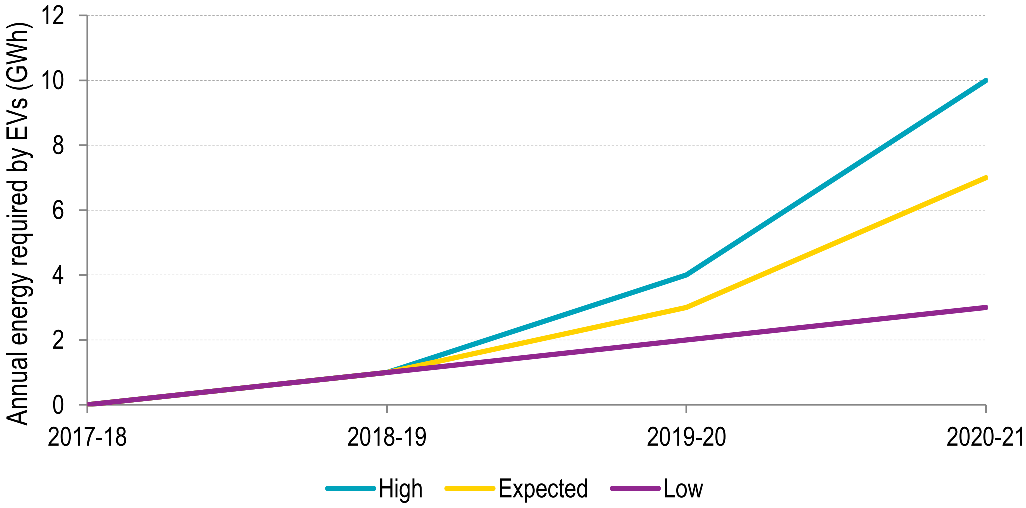
Figure 33: Behind the meter storage uptake for the WEM in each WEM 2018 ESOO scenario



B.5 Impact of electric vehicles

All scenarios consider an uptake of EVs providing a new source of electrical load as consumers switch from petrol-based vehicles to those that rely on charging from the grid as part of the decarbonisation effort. Figure 34 shows the assumed annual energy assumed to be required by EVs in each of the WEM 2018 ESOO scenarios.

Figure 34: EV energy demand trajectories for each WEM 2018 ESOO scenario



B.6 Thermal generation developments

In accordance with the Energy Minister's directive for the retirement of generation capacity in the WEM, the units listed in Table 15 are assumed to be retired in all scenarios as part of Synergy's 380 MW retirement schedule.[33]

Table 15: Synergy retirements			
Power station	Capacity (MW)	Fuel type	Retirement date
Kwinana Gas Turbine 1	21	Gas	30 September 2018
Muja A (G1, G2)	120	Black coal	Retired
Muja B (G3, G4)	120	Black coal	Out of service
Mungarra Gas Turbine 1, 2, 3	113	Gas	30 September 2018
West Kalgoorlie Gas Turbine 2, 3	62	Gas	30 September 2018

B.7 Large-scale renewable energy target

In June 2015 the Commonwealth Government legislated the revised LRET, ending a protracted review of the policy. The current legislated targets require 33,000 GWh per annum of eligible renewable energy from 2020 to 2030. Additional voluntary certificate surrenders are also expected, due to several state or territory policies, as well as consumer choice schemes such as the GreenPower program.

The WEM's assumed contribution to the LRET in the scenarios is as per the new entrant renewable capacity developments listed in Appendix B.7. Recognising that the LRET is a national policy, it has been assumed that the LRET is met largely by generation development projects in the NEM as is the current market expectation. No specific requirement is placed on WA's contribution to the RET.

B.8 Renewable capacity developments

Each scenario assumes the same list of new entrant renewable generators will be commissioned in the WEM as driven by the LRET. 539.7 MW of new generation is expected to be installed. A breakdown of the assumed new entrant renewable capacity development schedule for connection in the WEM is listed in Table 16.

[33] Synergy 380 MW announcement

Table 16: Assumed new entrant renewable capacity projects commissioned during forecast period				
Project name	Region	Capacity (MW)	Technology	Commissioning date
ALINTA_WWF	North Country	89.1	Wind	Existing
ALBANY_WF1	Albany	21.6	Wind	Existing
EDWFMAN_WF1	North Country	79.2	Wind	Existing
INVESTEC_COLLGAR_WF1	East Country	206	Wind	Existing
GRASMERE_WF1	Albany	13.8	Wind	Existing
GREENOUGH_RIVER_PV1	North Country	10	Solar PV - Fixed	Existing
MWF_MUMBIDA_WF1	North Country	55	Wind	Existing
Byford Solar	Kwinana	29.7	Solar PV - SAT	1/07/2018
Emu Downs Solar Farm	North Country	20	Solar PV - SAT	1/07/2018
Northam	East Country	10	Solar PV - SAT	1/07/2018
Badgingarra	North Country	130	Wind	1/07/2019
Cunderdin Solar Farm	East Country	100	Solar PV - SAT	1/07/2019
Greenough River 2	North Country	30	Solar PV - SAT	1/07/2019
Moonies Hill_S1	South Country	40	Wind	1/07/2020
Warradarge	North Country	180	Wind	1/07/2020

B.9 Generator forced and planned outage rates

Table 17 shows the outage rate statistics assumed in the modelling, based on an IMO review of the Planning Criterion[34] and a review of historical data.

Table 17: Forced outage rates statistics from the IMO planning criterion review		
Technology	Full forced outage rate (%)	Planned outage rate (%)
Coal	1.65	7.8
Gas (including cogeneration)	1.64	7.3
Gas/liquid fuel	1.3	8
Biomass (assumed same as gas liquid)	1.3	8
Wind and solar PV	Included in modelled capacity factor	

EY conducts a number of Monte Carlo iterations in the market modelling to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics. As shown in the table, the same outage statistics are applied for generators with the same fuel type.

The nature of outages for wind and solar generators is different to large thermal generating units due to the modular nature of wind turbines or solar panels within a power station.

The capacity factors modelled for wind and solar farms are based on observed and expected output of the wind and solar farms modelled, and as such implicitly include the impact of outages.

B.10 New entrant parameters and capital costs

The technology costs are based on projections published in the 2016 NTNDP report. However, solar PV and wind capital costs have been reduced, in line with views developed from industry consultation. The capital costs for other technologies have remained unchanged. Figure 35 shows the capital costs projections for the main technologies of interest for the forecast period.

Table 18 provides a summary of other new entrant parameters.

[34] IMO 5 Yearly Review of Planning Criterion

Figure 35: New entrant capital costs assumed for different technologies

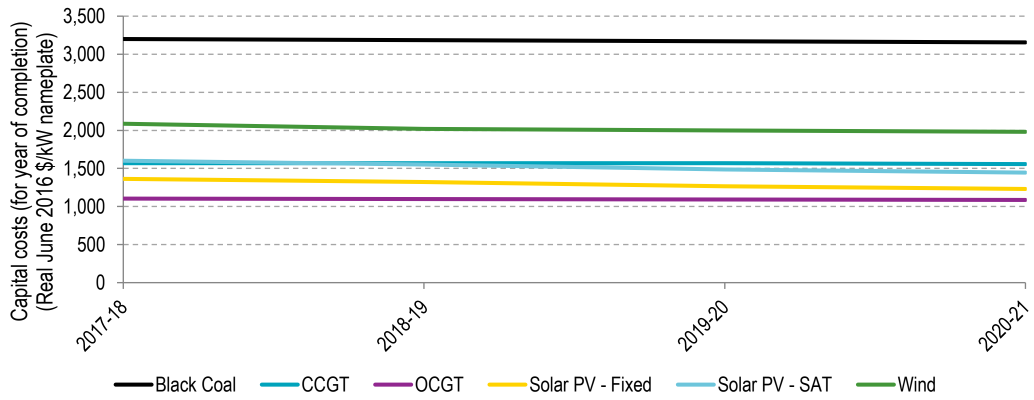


Table 18: New entrant parameters			
Technology	FOM ($/MW)	VOM ($/MWh sent-out)	Economic life (years)
Black Coal	42073	3	30
CCGT	43359	10	30
OCGT	10000	7	30
Solar PV - Fixed	30941	12	30
Solar PV - SAT	4000	10	30
Solar PV - DAT	25000	0	25
CST central receiver - (6 hour storage)	30000	0	25
Wind	40000	0	25
Large-scale storage (4 hours)	65000	4	30

B.11 Coal prices

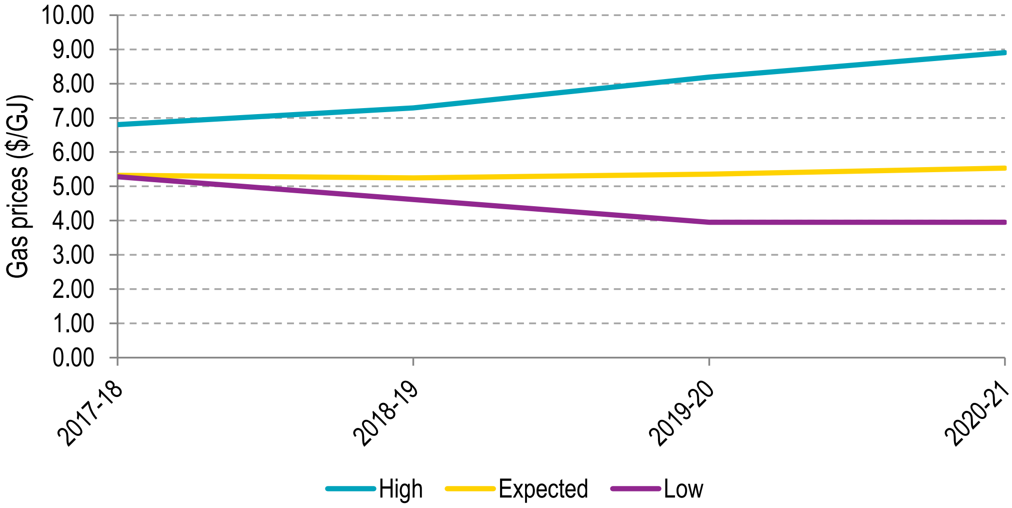
For this Project, EY has assumed that coal prices remain constant at $2.60/GJ in the forecast period.

B.12 New entrant gas prices

EY does not consider the impacts of short-term gas contracts in our modelling, rather considering the pricing effect of long-term gas contracts for gas powered generators. Figure 36 below shows the assumed gas price trajectory for the SWIS for uncontracted gas supplies, based on AEMO's 2017 Gas Statement of Opportunities (GSOO) base scenario.[35] As existing gas generators' current gas contracts roll off, EY expects that these generators will be forced to adopt this price trajectory for their future gas contracts.

[35] https://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities

Figure 36: Forecast gas prices for the SWIS (from the AEMO 2017 GSOO)



B.13 Marginal loss factors

Marginal loss factors which are published by AEMO[36] for the 2018-19 year are applied for all years.

[36] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

Appendix C Definitions and acronyms

Defined terms	
Capex	Capital expenditure
Iteration	Half-hourly modelling of a single possible outcome for a future set of years
Market modelling	The process of forecasting the expected generation mix and wholesale prices in the electricity market as an outcome of a set of input assumptions, including key drivers of the market. This involves iterating on several market Simulations to arrive at a final Simulation.
Region	There are five pricing regions in the NEM: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania
Residual demand	The demand required to be met by large-scale scheduled generation. This is calculated by taking the total customer electricity demand and netting off rooftop PV and large-scale wind and solar PV generation, as well as the net effect of behind-the-meter battery storage
Simulation	Half-hourly modelling of a future set of years, including multiple iterations for each year

Abbreviations	
2-4-C®	EY's in-house wholesale electricity market dispatch modelling software suite
APC	Administered price cap, applied as an alternative market price cap when market exceeds the CPT
CPT	Cumulative price threshold
DSP	Demand-side participation
FOR	Forced outage rate
LRET	Large-scale renewable energy target
MPC	Market price cap
NEM	National Electricity Market
USE	Unserved energy, expressed as percentage of a region's energy demand

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